July 31, 2003

VIA HAND DELIVERY

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: New England Power Pool and ISO New England Inc. -
FERC Docket ER03-___-000:
One Hundredth Agreement Amending New England Power Pool Agreement (Transmission Cost Allocation for New England)

Dear Secretary Salas:

I. Introduction:

The New England Power Pool ("NEPOOL") Participants Committee[1] and ISO New England Inc. ("ISO-NE") jointly submit an original and six (6) copies of this transmittal letter and amendments to the NEPOOL Tariff and the Restated NEPOOL Agreement to implement comprehensive provisions for transmission cost allocation for New England (the "TCA Amendments").[2] The Participants Committee files these changes pursuant to Section 205 of the Federal Power Act.

The TCA Amendments reflect an objective, non-discriminatory default cost allocation mechanism that is appropriate for New England in that it recognizes the tightly interconnected and dynamic nature of the New England transmission system. The mechanism is consistent with Commission policy regarding transmission network upgrades, and with the consensus principles developed through ISO-NE led stakeholder workshops on transmission cost allocation. The

---

[1] Capitalized terms used but not defined in this filing are intended to have the same meaning given to such terms in Section 1 of the Restated New England Power Pool Agreement (the "Restated NEPOOL Agreement" or "Agreement"), Section 1 of the Restated NEPOOL Open Access Transmission Tariff ("NEPOOL Tariff" or "Tariff") and/or Section 1.3 of Market Rule 1.

[2] The TCA Amendments are contained in the One-Hundredth Agreement Amending New England Power Pool Agreement ("100th Agreement"), included as Attachment 1 to this filing.

TCA Amendments were developed through a fully inclusive and extensive stakeholder process and have the broad support of ISO-NE and approximately 78% of NEPOOL.

As a whole, the TCA Amendments provide for participant-funding when a transmission upgrade is a private, market-based investment, when there is participant agreement as to the upgrade's beneficiaries, and in clearly defined circumstances discussed below. When participant agreement does not occur, the TCA Amendments provide a default mechanism under which there will be regional cost support of transmission upgrades that produce network-wide benefits and local cost support for upgrades that provide only a local benefit. The TCA Amendments are designed to promote the construction of needed transmission, thus improving system reliability and power markets efficiency, to the overall benefit of New England electricity consumers.

NEPOOL and ISO-NE request an effective date for the TCA Amendments of *October 1, 2003*.

Section II of this transmittal letter sets forth the background of the filing; Section III describes the TCA Amendments; Section IV provides the rationale for the TCA Amendments and responds to criticism of it that was considered and rejected by ISO-NE and the 78% of NEPOOL that supports the Amendments; Section V lists the specific rate schedule changes that will be made through the TCA Amendments; and Section VI provides additional supporting information related to this filing as required by the Commission's regulations.

II. Background:

NEPOOL, ISO-NE, state regulators and the other New England stakeholders have been grappling for at least the past three years with the difficult issue of how to allocate appropriately the costs of transmission expansion/upgrades. A series of pleadings and orders regarding this subject in various dockets culminated in the December 20, 2002 order issued in the New England Standard Market Design proceeding, Docket No. ER02-2330 (the "December 20 Order")[3].

The December 20 Order 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] The December 20 Order provided guidance with respect to the cost roll-in to regional rates of needed upgrades identified in the NEPOOL Transmission Plan for 2002, including certain upgrades in Southwest Connecticut.[5] It also

[3] New England Power Pool and ISO New England, Inc., 101 FERC ¶ 61,344 (2002). The Commission's orders on this subject are discussed more fully in Section IV of this transmittal letter.

[4] December 20 Order at P 51.

[5] Id. at P 36.

recognized that there was an ISO-NE led stakeholder process underway, designed to help develop consensus on a proposal to be filed and implemented prospectively.[6]

The ISO-NE led stakeholder process consisted of a series of four broadly-attended "workshops" beginning on November 15, 2002 and ending on March 14, 2003.[7] Through presentations and discussions, all interested stakeholders attending those workshops considered and discussed numerous relevant factors for developing a cost allocation proposal for New England. Those factors included, among others, the following: (1) the history of transmission development in New England; (2) the tightly integrated characteristic and usage of the New England transmission system; (3) the existing cost allocation system under the NEPOOL Tariff; (4) approved cost allocation methods in other parts of the United States; (5) recent Commission orders to NEPOOL/ISO-NE on the subject as well as orders and policy statements made outside of the New England context (such as the "SMD NOPR"); and (6) the input of Dr. David Patton, Independent Market Advisor, to the ISO-NE Board of Directors, regarding the interaction of transmission cost allocation methods and a locational marginal pricing system.

The stakeholder process was open to all interested parties, and the workshops were well attended. In addition to Participants, attendees (in person or by telephone) included public interest representatives, commissioners for the New England state public utility commissions and their staff and consultants, members of ISO-NE's Board of Directors, and FERC staff.[8]

Through the workshops, the stakeholders identified a list of principles to guide the development of a cost allocation methodology. That list was refined down to six principles that appeared to have consensus support (the "Consensus Principles").[9] The Consensus Principles are that the transmission 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.

ISO-NE and the stakeholders used the Consensus Principles to frame the discussion for several straw default cost allocation proposals that were presented. The straw default cost allocation proposals covered a range of options that included the following methods to allocate transmission upgrade costs:

---

[6] Id. at P 51.

[7] Presentations and whitepapers prepared for the Working Groups can be found at: http://www.iso-ne.com/seminars/seminar_materials.html (under the headings Transmission Cost Causation Workshop).

[8] Attendance lists for the four workshops are provided as Attachment 6.

[9] The Consensus Principles are discussed in Section IV(E) of this letter, pp. 20-22.

(a) a study of each upgrade and an assignment of costs for the life of the upgrade to those entities that the study identifies as the beneficiaries of the upgrade;

(b) a study of each upgrade and an assignment for the first five years to those entities that the study identifies as the beneficiaries of the upgrade and then regional cost support for the remaining life of the facilities;

(c) a tiered voltage approach in which the level of regional cost support for the upgrade would depend on the voltage level of that upgrade; and

(d) the currently-approved cost allocation that rolls in all costs for looped facilities rated 69kV or above.[10]

After taking into consideration the extensive stakeholder discussions of the straw proposals and technical analysis by its staff, ISO-NE presented the conceptual straw proposal it identified as most appropriate for New England and the rationale for it at the March 14, 2003 Stakeholder Workshop. In essence, ISO-NE's recommended proposal included participant funding for the following types of transmission upgrades: Elective Transmission Upgrades, Generator Interconnection Related Upgrades, Merchant Transmission Facilities, Local Benefit Upgrades (which are described and defined in greater detail below), and Localized Costs (those incremental costs associated with a network upgrade that have been determined by ISO-NE to be in excess of those required to satisfy a regional need). That proposal also included regional cost support for RTEP02 Upgrades (which are described further below) and Regional Benefit Upgrades (which also are described further below).[11]

Beginning in April 2003, ISO-NE and NEPOOL counsel drafted detailed language changes to the NEPOOL Tariff to reflect the conceptual proposal. That language was reviewed fully with the NEPOOL Tariff Committee. The Tariff Committee review process continued through several meetings in April and May, during which time ISO-NE continued to consider

---

[10] The stakeholder workshop document that contained the straw proposal is included as Attachment 7.

[11] The upgrades located in Southwest Connecticut as identified by ISO-NE in RTEP02 were appropriately considered by the Stakeholder Working Group. As ISO-NE and NEPOOL explained in their July 7, 2003 Compliance Report (in Docket No. ER02-2330-000), the Stakeholder Working Group was cognizant of and discussed the December 20 Order when determining appropriate transition mechanisms for New England and appropriate cost allocation principles. Thus, the ISO and NEPOOL have already anticipated the Commission's directive in its June 6, 2003 Order (in Docket No. ER02-2330-000) to consider upgrades for Southwest Connecticut. As explained in detail in this filing, the principles and recommended methodology from the Stakeholder Working Group would provide regional cost support to needed transmission upgrades that are 115kV and above and that meet certain functional criteria. The upgrades for Southwest Connecticut meet that criteria. In short, under the criteria developed, "an appropriate percentage of the costs of [SWCT projects] to be socialized" would be one hundred percent.

and refine the proposal, taking into account the input of the Tariff Committee. On June 11, 2003 the Tariff Committee voted to approve the amendments reflecting ISO-NE's proposal and recommend their approval by the NEPOOL Participants Committee. The amendments that were recommended by the Tariff Committee to the NEPOOL Participants Committee thus reflected the outcome of the four stakeholder workshops, plus the further consideration of ISO-NE and the NEPOOL Tariff Committee.

The proposal that was sent to the Participants Committee would have allocated costs of Reliability Upgrades regionally, but would have allocated regionally the costs of Economic Upgrades *only if* they provided economic benefits to *each and every* sub-area within New England – as opposed to providing a *net* economic benefit to the entire region (*i.e*., a test under which some sub-areas might experience an *increase* in costs as a result of the "Economic Upgrade").[12] Initially, ISO-NE supported that proposal because of a general concern about imposing on a sub-region the costs of a particular transmission upgrade if studies did not show an economic benefit for that sub-region. During Participants Committee deliberations of this aspect of the ISO-NE proposal, however, substantial practical reservations were raised.

Specifically, a requirement that every proposed regional upgrade be proved to benefit every sub-region in New England undoubtedly would lead to extensive and time consuming debates for each upgrade over the issue of whether every sub-region benefits from that upgrade. Such a requirement, Participants argued, would effectively eliminate the advantages of any default cost allocation, since every allocation would be exposed to challenge. This would in turn delay or even prevent projects that provide net benefits to the region. Moreover, under standard market design in New England, economic beneficiaries among and within sub-areas of the region can change rapidly as trading patterns, bid strategies, generator availability and fuel prices (to name just a few factors that impact prices within sub-areas) change. As a result, because of the dynamic and tightly integrated nature of the New England bulk power system, and because of the short-lived nature of economic benefits, distinguishing economic costs and benefits on a sub-area basis provided an unreasonable test for determining whether an Economic Upgrade should be given regional cost support.

Following discussion of these concerns, the Participants Committee voted with approximately 77% support to modify the ISO-NE proposal to require a net economic benefit for the region and then voted with 74% support to ballot the modified proposal.[13] The modified proposal, which is reflected in the TCA Amendments, was then balloted for signatures. Based

[12] In addition to supporting a test that would require that "each and every sub-area" must benefit from an Economic Upgrade, ISO-NE would have supported an exemption to the test for those upgrades that were under $20 million, in order to facilitate regional funding for those Economic Upgrades whose costs would be minimal for network load. Given the modification made by the Participants Committee, this proposal was not subject to a vote.

[13] A record of the Participants Committee votes are included as Attachment 8 to this letter.

on that balloting, *it has now been approved by approximately 78% of NEPOOL*.[14] In addition, on July 14, 2003, the Transmission Owners Committee voted in favor of the 100th Agreement, with six out of the seven Transmission Owners supporting it.[15]

Thus, after years of debate and almost eight months of much concerted effort through an organized and fully inclusive stakeholder process, NEPOOL and ISO-NE are jointly filing a comprehensive transmission cost allocation proposal that is broadly supported and is appropriate for New England.[16] The proposal has been thoroughly scrutinized, discussed and debated, with alternatives considered, by all interested stakeholders. NEPOOL and ISO-NE have worked diligently to maximize stakeholder support for the proposal reflected in the TCA Amendments on what is a very controversial subject in New England and throughout the country. NEPOOL and ISO-NE urge the Commission to honor the stakeholder process, accept the TCA Amendments, and allow New England to move forward to ensure a robust transmission network for the benefit of all customers.

III. Regional Transmission Expansion Planning and the TCA Proposal:

A. Description of Planning Process and Application of Default Cost Allocation Rules

The TCA Amendments need to be viewed in conjunction with the existing regional transmission expansion planning ("RTEP") process in New England. Under the NEPOOL Tariff today, the regional planning process relies on market participants to provide resources (*e.g.*, generation, demand-side projects, and merchant or elective transmission) in response to system needs identified by ISO-NE through the RTEP process. Under that process, ISO-NE identifies transmission projects (*i.e.*, either Reliability Upgrades or Economic Upgrades) in the event that market responses are insufficient to address needs identified by ISO-NE.

Consistent with the FERC's suggestions in the SMD White Paper[17], the default cost allocation method proposed herein would apply only to upgrades that ISO-NE defines as Reliability Upgrades and Economic Upgrades through the RTEP process and that are not

---

[14] A record of the balloting results is also included as part of Attachment 8 to this letter.

[15] Although some stakeholders in Maine have been critical of the proposal, NEPOOL and ISO-NE note that Bangor Hydro-Electric Company and several End Users from Maine support the TCA Amendments.

[16] At the Participants Committee meeting an alternate conceptual proposal was put forward by the Maine and Rhode Island public utility commissions. No other New England state indicated its support for that proposal, nor did any Participants or ISO-NE. The proposal, which was characterized as a "settlement offer", is Attachment 9 to this transmittal letter. No transmission cost allocation proposal has received the support of all six of the New England state public utility commissions.

[17] See Federal Energy Regulatory Commission White Paper Wholesale Power Market Platform; Issued April 28, 2003 ("SMD White Paper") at pp. 14-15.

addressed through participant funding (i.e., market responses or other agreements among participants to fund the needed transmission upgrades).

The RTEP process is designed to ensure that the only upgrades supported regionally under the NEPOOL Tariff are those upgrades that ISO-NE determines either are needed for reliability or are projected to produce net economic benefits for the region. *By working in conjunction with the RTEP process, the TCA Amendments result in regional cost support for projects that are needed and that provide regional benefits, while giving the market the first opportunity to provide participant funded solutions to system needs.*

B. ISO-NE Classification of Transmission Upgrades

Pursuant to the NEPOOL Tariff, ISO-NE classifies upgrades as Reliability Upgrades or Economic Upgrades during the RTEP process. That process is designed to collect and reflect broad input from all stakeholders through the Transmission Expansion Advisory Committee ("TEAC"). The TEAC includes participation not only by ISO-NE and Participant representatives, but also representatives from state regulators, public interest groups and retail customers.

Reliability Upgrades are defined in § 1.106 of the NEPOOL Tariff as those transmission upgrades that are

> not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the NEPOOL 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 NEPOOL 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 Upgrades.

ISO-NE identifies Reliability Upgrades by conducting system resource adequacy assessments in accordance with NERC, NPCC and NEPOOL Planning Procedure guidelines. Through review of acceptable stability response, short circuit capability, system voltage levels and thermal capabilities, ISO-NE identifies those transmission upgrades that are necessary to ensure that the New England region as a whole meets established reliability criteria. In doing so, it seeks to ensure that uninterrupted electricity service can be provided throughout the entire New England region despite the occurrence of contingency events, such as resource outages. Such upgrades are classified, therefore, as Reliability Upgrades.

Economic Upgrades are those upgrades that are defined in the planning process to provide net economic benefits to the region. To project whether there are likely to be net economic benefits to the region, ISO-NE analyzes among other things load projections both regionally and locally, generator availability, fuel costs and availability, proposed new generator projects and their likelihood of completion. As discussed in greater detail in section III.C.2 below, the definition of Economic Upgrade is being refined to ensure that ISO-NE analysis properly considers other factors in its economic analysis beyond simply changes in projected Congestion Costs. Such factors might include, but are not limited to: energy costs, operating reserve charges, system losses, capacity costs, and other regional or location specific market costs. ISO-NE would identify such Economic Upgrades by analyzing loads, generator availability, fuel costs, fuel availability, and proposed system additions and retirements, including transmission enhancements, demand side resources, and new/retired generators.

C. The Categories of Transmission Upgrades and their Cost Allocation

The TCA Amendments provide a combination of participant funding and regional cost support, depending on the category of upgrade, modification or addition to the transmission system. Participant funding is understood among the stakeholders here to mean the payment for transmission by those entities (which are a subset of transmission customers throughout the region) that request, require or voluntarily undertake the building of new transmission in New England. As a practical matter, such entities are the ones that have caused the costs and/or will derive the benefits of the new transmission, and thus appropriately pay for it.[18]

Regional cost support means that the costs of the transmission facilities will be rolled into the regional transmission rates paid by all network transmission customers under the NEPOOL Tariff (and, it is presumed, the successor RTO tariff for New England). NEPOOL and ISO-NE expect that transmission facilities that receive regional cost support will provide network benefits throughout New England over the life of such facilities.

1. Transmission Receiving Participant Funding

The set of participant funded transmission includes transmission and/or related costs in the following categories: Generator Interconnection Related Upgrades,[19] Elective Transmission

[18] The TCA Amendments carry out the principle of "beneficiary pays" to the extent practicable while recognizing and addressing the free rider problem, which is discussed *supra* at pp. 14-15 of this letter.

[19] Under the existing Schedule 11 of the NEPOOL Tariff, all new Generator Interconnection Related Upgrades are paid for by the interconnecting generator.

Upgrades, Local Benefit Upgrades, Merchant Transmission Facilities, and Localized Costs. The cost allocation for generator interconnections, Elective Transmission Upgrades and Merchant Transmission Facilities is unchanged from the Commission-approved filed rate in the NEPOOL Tariff.[20] *Local Benefit Upgrades ("LBUs")* and *Localized Costs* are new definitions being added to the NEPOOL Tariff with new cost allocation provisions associated with them. They are described below.

a. Treatment of Local Benefit Upgrades

Local Benefit Upgrade(s) are defined with reference to both a voltage test and a functionality test to determine whether a transmission facility will benefit only a sub-region of NEPOOL and, therefore, not justify regional cost support. The definition of LBU is: "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 Section 15.1 of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England)."

The voltage criteria used in the definition of LBU reflect the practical, simplifying assumption that facilities rated below 115kV may not provide sufficient network benefits across the New England transmission system to justify regional cost support. The functionality test looks to the same non-voltage criteria that are currently used to identify Pool Transmission Facilities ("PTF"). In essence, these non-voltage criteria identify whether the transmission facility is a looped facility that allows for the free flow of power on the regional system. Thus, even if a transmission facility meets the voltage criterion, it may not provide a regional benefit (the obvious example is a 345kV radial line).

Under the new Schedule 12, which contains the cost allocation provisions, LBUs will not receive regional cost support, and thus, if built, would be subject to participant funding, including funding through payment of the Local Network Service rates of Local Network transmission providers in New England.

b. Treatment of Localized Costs

Localized Costs are costs associated with Regional Benefit Upgrades and RTEP02 Upgrades (categories of Transmission Upgrades eligible for regional cost support, described further below) that ISO-NE determines to be unreasonable to be supported on a regional basis as Pool-Supported Costs. ISO-NE's determination will be made in light of a number of factors, including: Good Utility Practice, current engineering design and construction practices in the

[20] Under existing NEPOOL Tariff Section 50.2 and Schedule 18, respectively, Elective Transmission Upgrades and Merchant Transmission Facilities are participant funded, receiving no regional cost support.

area in which the transmission is being built, alternate feasible transmission upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed upgrade. Such costs could include, for example, incremental costs of "gold-plating" or the construction of transmission lines underground when such construction is not justified.

The procedure for determining Localized Costs is spelled out in the proposed Schedule 12C and would replace the current cost review procedure administered by the NEPOOL Reliability Committee under Section 15.5 of the Restated NEPOOL Agreement and NEPOOL Planning Procedure 4. The Reliability Committee would still take an active role in providing input in this process but ISO-NE would be the sole decision-maker regarding Localized Costs (aside from disputes which go to the Commission).

Under Schedule 12C, the applicant sponsoring a Regional Benefit Upgrade ("RBU") or RTEP02 Upgrade will provide information about the project to ISO-NE, including: a technical analysis of the project, an assessment of the impact of the construction of the project on the bulk power system, alternate feasible transmission designs considered, and a discussion of why the Transmission Upgrade was selected over other feasible and practical transmission alternatives, with a description of the benefits of the proposed Transmission Upgrade over other feasible and practical transmission alternatives from an operational, timing of implementation, cost and reliability perspective. ISO-NE would not consider local siting requirements (e.g., state requirements that transmission be installed underground) to be dispositive of whether or not Localized Costs exist.[21] *Localized Costs will not receive regional cost support*.

Schedule 12C also provides a "second-look" mechanism, under which if the costs associated with a Transmission Upgrade actually exceed by ten-percent or more the estimated Pool-Supported PTF costs determined in the original Localized Costs review, or the design associated with the construction of a Transmission Upgrade is materially changed subsequent to ISO-NE's determination of Localized Costs, then the applicant for Pool-Supported PTF costs shall be required to submit its Transmission Upgrade again for ISO-NE review to determine if any of the incremental costs or costs associated with the change in design are Localized Costs.

2. Transmission Receiving Regional Cost Support

Under the TCA Amendments, the set of transmission categories that will receive regional cost support include NEMA Upgrades, RTEP02 Upgrades and Regional Benefit Upgrades. NEMA Upgrades and transmission that was PTF as of December 31, 2003 will continue to receive the regional cost support already established under the NEPOOL Tariff.[22]

---

[21] State siting requirements should not be used to justify regional cost support for transmission design and construction that is otherwise unreasonably costly in light of the design and construction factors considered under Schedule 12C.

[22] Regional cost support up to $35 million for NEMA Upgrades was approved in ISO New England Inc., 91 FERC ¶ 61,311, at 62,076 (2000). The list of NEMA Upgrades is contained in the TCA Amendments as the new Schedule 12A. Existing PTF is transmission in New England that is rated 69kV

a. RTEP02 Upgrades Would Appropriately Receive Regional Cost Support.

RTEP02 Upgrades are Transmission Upgrades that were included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") published in 2002, as approved by the ISO-NE's Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO-NE. The RTEP02 Upgrades are listed in Schedule 12B that is added to the NEPOOL Tariff by the TCA Amendments.[23] Their inclusion is consistent with the December 20 Order, which stated that regional cost support rate treatment would apply to projects already under construction or planned under the regional planning process in New England.[24] The RTEP02 Upgrades are upgrades that have been identified as needed through the regional planning process.

b. Regional Cost Support is Appropriate for RBUs

The final category of transmission to receive regional cost support on a prospective basis is the Regional Benefit Upgrade category. Establishment of this RBU category provides an objective, non-discriminatory default cost allocation mechanism consistent with the Commission's orders to NEPOOL and ISO-NE on this subject.[25] The RBU definition uses a

---

or above and meets the non-voltage criteria enumerated in Section 15.1 of the Restated NEPOOL Agreement. The December 20 Order stated that the new cost allocation would apply prospectively only. *The cost support method for existing transmission is not being changed by the TCA Amendments.*

[23] The list of Schedule 12B upgrades was formulated by the NEPOOL Tariff Committee and ISO-NE. It consists of those transmission upgrades identified in the 2002 NEPOOL Transmission Plan, *see* RTEP02, App. 13.11, as well as those upgrades identified as needed "to assure that the New England interconnected bulk power supply system is designed with sufficient transmission capacity to reliably and efficiently integrate resources and serve area loads," *see* RTEP02 § 4.0. This compilation of transmission upgrades was deemed fair and non-discriminatory because, while RTEP02 appeared as suitable benchmark for "grandfathering" upgrades, due to resource limitations, RTEP02 had not defined in equivalent detail all transmission upgrades that RTEP02 determined to be needed.

[24] December 20 Order at n. 15; see also Id. at P 51 ("In order to avoid possible disruption to current projects, the mechanism developed through this stakeholder process will become effective only prospectively.").

[25] New England Power Pool and ISO New England Inc., 101 FERC ¶ 61,344, at P 51 (2003) ("[W]e have been urging New England to develop an objective, non-discriminatory default mechanism to allocate the costs of upgrades which are not clearly either beneficial solely to a discrete party or group of parties or beneficial to the entire pool"); New England Power Pool and ISO New England Inc., 100 FERC ¶ 61,287, at P 144 (2002) ("[W]e will require ISO-NE to develop a mechanism which, in situations where the parties cannot agree as to who benefits from the upgrade, provides an objective, non-discriminatory default cost allocation mechanism that is consistent with the principles of cost causation"); ISO New England Inc., 100 FERC ¶ 61,029, at P 8 (2002) ("[W]e will require ISO-NE and/or NEPOOL to propose a revised default cost allocation methodology in ISO-NE's or NEPOOL's SMD filing consistent with an

bright line voltage and functionality test to establish a presumption that transmission that meets the RBU definition *will provide network benefits throughout New England over the life of those transmission facilities*.[26] The RBU definition is:

> **Regional Benefit Upgrade(s) ("RBU(s)"):** a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in Section 15.1 of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England); and (iii) is included in the NEPOOL Transmission Plan as either a Reliability Upgrade or an Economic Upgrade identified as needed pursuant to Section 51 of this Tariff. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of this Tariff (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115 kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in Section 15.1 or Section 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England).[27]

Only those upgrades that are needed for a regional reliability or economic purpose will qualify as RBUs. As explained in Sections III.A and B above, the default allocation applies only to needed Reliability Upgrades and Economic Upgrades that are properly categorized as such in the RTEP process. Such upgrades are identified only after the market has had an opportunity to respond to identified opportunities for market-based solutions, including participant-funded transmission.

An essential element of the definitions of Reliability Upgrade (as it exists now in the NEPOOL Tariff) and Economic Upgrade (as it is being amended under the TCA Amendments), is that *such upgrades provide system-wide benefits*. The definition of Reliability Upgrade

---

LMP scheme"); ISO New England Inc., 98 FERC ¶ 61,173, at P 51 (2002); ISO New England Inc., 95 FERC ¶ 61,384, at 62,433 (2001) ("ISO-NE's mechanism should assign costs directly where there is agreement among the participants, and should develop objective, non-discriminatory guidelines to allocate costs where participants are unable to agree"); ISO New England, 91 FERC ¶ 61,311, at 62,076-76 (2000).

[26] Section IV (C) explains in more detail why 115kV+, looped transmission is a reasonable and appropriate bright line to use as the objective, non-discriminatory default mechanism for regional cost support of transmission in New England. Additionally a flow-chart, included as Attachment 10, shows the application of the cost allocation method, with RBUs receiving regional cost support.

[27] The RBU definition also grandfathers upgrades to existing PTF that could be rated less than 115kV but that continue to meet the definition of PTF contained in Section 15.1 of the Restated NEPOOL Agreement.

provides in pertinent part that *such upgrades are necessary "to ensure the continued reliability of the NEPOOL system…*". The amended definition of Economic Upgrade is:

> Those additions and upgrades that are not related to the interconnection of a generator, and, in the System Operator'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 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. (Emphasis added.)

Thus, by applying the RTEP screening mechanism to identify needed Reliability Upgrades and Economic Upgrades and the bright line RBU test, only needed Transmission Upgrades that provide network-wide benefits will receive regional cost support prospectively.[28]

IV. Rationale for TCA Proposal and Response to Anticipated Objections

A. Regional Cost Support for Regional Benefit Upgrades Is Appropriate for New England

In considering a transmission upgrade allocation method for New England, the Commission has stated that "*[o]f course, we recognize that upgrades of transmission networks often benefit essentially the entire grid rendering any specific cost assignment impractical because net benefits are too diffuse*."[29] (Emphasis added.) This rationale applies directly to the types of upgrades for which the TCA Amendments will provide regional cost support. The New England Control Area is a tightly interconnected transmission network, perhaps more so than any other centrally dispatched control area in the country. *Needed upgrades of a sufficient size to one part of the New England grid virtually always provide diffuse benefits throughout the integrated network, often immediately and certainly over the useful life of those facilities.*

In the Commission's consideration of the reasonableness of the TCA Amendments for New England, it is important to recognize that the six-state New England region, while a

---

[28] A Transmission Upgrade is defined in the TCA Amendments as "an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of this Tariff governing rates and service on the PTF on or after January 1, 2004. The categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of this Tariff." The definition of PTF as applied to Transmission Upgrades on and after January 1, 2004 is modified in the TCA Amendments to reflect the higher voltage standard of RBUs (115kV or above). Existing PTF and upgrades to it will not be affected by this change.

[29] ISO New England Inc., 91 FERC ¶ 61,311, at 62,076-77 (2000).

substantial and discrete market, is relatively small in comparison to other single utility systems in the United States.

In forming the TCA Proposal, NEPOOL and ISO-NE also took into account the dynamic nature of the New England transmission system, particularly how usage and beneficiaries change over time.[30] Again, by way of example, existing planning studies reflect an expectation that newer generators fueled by natural gas will be lower-priced and therefore dispatched more often than older generators fueled by oil. During the increase in natural gas prices this past March, however, the reverse proved to be true. As a result, regions that were typically importing less expensive energy from natural gas plants were actually exporting lower-priced energy from oil plants to other regions of New England. The actual energy flows in March demonstrated well the notion that beneficiaries of transmission facilities can shift dramatically based on changed circumstances. Similar shifts could occur with, for example, major generator outages or drought conditions restricting available hydroelectric power.

Thus, even if a discrete subset of beneficiaries could be identified (e.g., load in a single Load Zone) and the costs of an upgrade could be assigned to it initially without great difficulty, over time-- sometimes quite quickly-- the beneficiaries of that upgrade *are almost certain to change as system conditions change*. When that happens, costs would either have to be re-allocated, causing uncertainty and instability for investors and customers, or the costs would continue for a group that may no longer receive any special benefit while others get a "free ride". Either of these consequences is undesirable.

It would be equally undesirable if regional transmission upgrades that would relieve transmission constraints that sometimes separate the region into discrete sub-markets, to the overall net benefit of the region, were delayed or blocked by market participants who actually benefit from the persistence of congestion. For example, load-serving entities in sub-regions with excess generation may claim a "right" to the resulting lower locational prices, even if they have not contracted with the owners of the generating units in their "generation pockets." Similarly, generators in load pockets may seek to preserve the higher prices that they can command through the barriers that transmission constraints present to their competitors. The TCA Proposal, by providing for a well structured and applied default cost allocation methodology, appropriately limits the opportunities of such market participants to perpetuate these conditions by delaying the installation of needed upgrades through prolonged attempts to identify unique beneficiaries of proposed upgrades. Ultimately, the proposed treatment of regional benefit upgrades will support the Commission's goal of broad and economically efficient regional markets and stable bilateral contracts.

---

[30] As explained further on p. 20 of this letter, in just the seven years since ISO-NE assumed operational control of the New England grid, NEPOOL and ISO-NE have witnessed numerous changes in the use of the system that resulted in changes to the beneficiaries of certain transmission facilities.

B. The RBU Default Mechanism Is Preferable to Case-By-Case Determinations

The Commission's long-standing directive to New England has been to establish a *default* cost allocation methodology (see *supra*, n. 23). That Commission directive properly recognizes that establishing a default mechanism based on objective, bright-line criteria is desirable from both policy and technical perspectives.

One of the principles clearly identified in the stakeholder working group was ease of implementation of the proposed default cost allocation mechanism. Relying on individual study of transmission projects – while appropriate for planning purposes – is not appropriate for determining cost allocation. There will certainly be cost and planning studies that identify undeniably that net benefits will result from proposed upgrades. Details concerning alternative data input and assumptions are not likely to change those conclusions about net regional benefits. The same cannot be said, however, if these data and assumptions are used to assign costs intra-regionally. Under standard market design in New England, economic beneficiaries among and within sub-areas of the region can change rapidly as trading patterns, bid strategies, generator availability and fuel prices (to name just a few factors that impact prices within sub-areas) change. As a result, because of the dynamic and tightly integrated nature of the New England bulk power system, and because of the short-lived nature of economic benefits, distinguishing economic costs and benefits on a sub-area basis provided an unreasonable test for determining whether an Economic Upgrade should be treated to regional cost support.

Case-by-case studies for cost allocation purposes virtually assures time-consuming and contentious disputes over every study. The default mechanism contained in the TCA Amendments avoids the time and resource consuming disputes that would inevitably result from a case-by-case study method of allocating costs.

C. The Criteria Determining Appropriate Transmission Upgrades for Regional Cost Support Are Reasonable and Objective

1. The 115kV Voltage Criteria provides an appropriate bright-line test.

The TCA Amendments establish that one prerequisite for transmission upgrades receiving regional cost support is that those upgrades are 115kV or above. Transmission facilities rated 115kV and above comprise approximately 95% of the existing pool transmission facilities in New England, and because of their performing characteristics, presently function to transmit power from the broad array of resources in New England throughout the pool. Moreover, this voltage-based criteria can be applied objectively. Given the topography of the New England Transmission System, generally facilities rated below 115KV are facilities used to meet local requirement and/or for distribution.

2. The Non-Voltage Criteria provides an appropriate bright-line test.

Regional cost sharing provided for in the TCA Amendments would also apply only to those upgrades that provide parallel looped capability to the PTF. In adopting these criteria, the TCA Amendments continue the long-applied and Commission-approved means of distinguishing PTF in New England from Non-PTF. It is appropriate to continue to distinguish those transmission facilities that allow power to move freely throughout the transmission system from those that allow power to flow two ways and those transmission facilities that are "radial" feeds to load or generating sources (excepting high voltage, direct current interconnections that allow for the flow of power between neighboring control areas). Facilities which provide parallel path capability more properly receive regional cost support (provided that they are needed and meet certain voltage criteria). The beneficiaries from these networked facilities are too diffuse to identify with reasonable specificity. As opposed to "radial" lines (which clearly serve identifiable load or generation sources), facilities that provide parallel carrying capability allow generating sources from diffuse areas to serve network load without distinction. Finally, such parallel path facilities are clearly identifiable as they loop from two geographically separate points on the transmission system

D. The TCA Amendments Are Consistent with Commission Policy and Precedent

1. The TCA Amendments are consistent with past orders to NEPOOL and ISO-NE

The September 20, 2002 Order required "ISO-NE to develop a mechanism which, in situations where the parties cannot agree as to who benefits from the upgrade, provides an objective, non-discriminatory default cost allocation mechanism that is consistent with the principles of cost causation."[31] The TCA Amendments satisfy this requirement. The default cost allocation is objective, using voltage ratings and functionality of upgrades as key determinants. It is non-discriminatory, applying the same test to all eligible transmission. It is a default mechanism, which applies in the absence of participant funding of transmission. It is consistent with the principles of cost causation, by first recognizing that RBUs result in benefits to load system-wide, and then spreading those costs to load system-wide.

---

[31] As noted above, previous orders to NEPOOL and/or ISO-NE have given similar direction. The June 13, 2001 Order provided guidance that is squarely aligned with the TCA Proposal. It stated as follows: "*We recognized that assignment of costs to those who benefit may be impractical in cases when benefits for certain expansions and upgrades are too diffuse. For those situations, we directed ISO-NE to develop and apply an objective, non-discriminatory default cost allocation mechanism. As we stated in the June 28 Order, ISO-NE must adopt a method of assigning costs similar to that used by PJM (although not necessarily the exact method used by PJM). ISO-NE's mechanism should assign costs directly where there is agreement among the participants, and should develop objective, non-discriminatory guidelines to allocate costs where participants are unable to agree.*" ISO New England Inc., 91 FERC ¶ 61,384, at 62,433 (2001)(Emphasis added).

In their joint request for rehearing of the September 20 Order, NEPOOL and ISO-NE requested that they not be precluded from proposing a cost allocation mechanism that would allow for regional cost support for transmission upgrades.[32] *The December 20 Order granted this request for rehearing, stating that the Commission would "not foreclose any cost allocation mechanism", but instead would allow the stakeholder process to develop a proposal.*[33] The Commission's SMD White Paper reinforced this message of allowing regional flexibility in, among other things, the development of transmission cost allocation proposals.[34]

The TCA Amendments are consistent with SMD. They allow for participant funding of transmission and the receipt of financial transmission rights-related benefits to those who undertake Elective Upgrades that increase the transfer capability of the NEPOOL Transmission System. They rely on the RTEP process to make information available, including LMP data, to enable market participants to identify opportunities for market responses to needs on the grid. Those responses could include merchant generation, merchant transmission, demand-side resources, or other new technologies. Only when the market fails to respond to identified needs do regulated transmission solutions go forward. Only those regulated transmission solutions that provide a regional benefit will receive regional cost support. Furthermore, the TCA Amendments leave the costs of Local Benefit Upgrades and Localized Costs to be paid by the load in the local area that benefits from the upgrade or additional costs.

The conclusions of ISO-NE's Independent Market Advisor, Dr. David Patton, further support the view that the TCA Amendments are consistent with SMD. In a paper he prepared for the New England stakeholders, entitled "Allocating The Cost Of Transmission Investment Under Locational Marginal Pricing", Dr. Patton summarized his conclusions as follows:

> In summary, the private investment process described in the prior section [private merchant investment in return for financial transmission rights] is the investment method most consistent with LMP because it relies entirely on the economic signals provided by the LMP system to generate privately-funded new investment. *When this is insufficient, it is justified to allocate costs of large investments made pursuant to a regional planning process relatively broadly since such investments will not likely be adequately compensated through new CRRs and because the network effects are more likely to be regional in scope. Allocating these costs more broadly is not inconsistent with LMP since it will occur in cases where the LMP signs are insufficient to bring about economically efficient or necessary new investment. Further such an allocation will do nothing to distort or otherwise hinder the operation of the LMP energy and ancillary services markets.* (Emphasis added.)

---

[32] Joint Motion for Clarification, or in the Alternative, Request for Rehearing of NEPOOL and ISO-NE, dated October 21, 2002, at p. 2.

[33] December 20 Order at P 51.

[34] See SMD White Paper, Appendix A at p. 13.

Some may argue that past orders have required a form of locational marginal pricing of all transmission upgrades, with a required determination of specific beneficiaries for each upgrade and a specific assignment of costs, in effect treating transmission as if it were energy. There is no such requirement in any of the Commission's orders to NEPOOL, ISO-NE or any other jurisdictional entity in the country. Nor should there be. Transmission is not energy and should not be treated the same. Energy is a commodity that is transmitted and used instantaneously, while transmission is the network infrastructure that allows for the delivery of that commodity. It is appropriate to send real-time, location-specific price signals to consumers and producers of energy, because its supply and demand does vary from moment to moment and from location to location and its costs/benefits can be quantified accordingly. RBU-type transmission, however, is like a part of the national highway system that is paid for by all taxpayers, because its benefits and costs are long-lasting and diffuse.[35]

2. The TCA Amendments are consistent with the Commission's long-established transmission pricing policy.

Repeatedly the Commission "has held that the integrated grid is a cohesive network whose expansion benefits all users of the grid and has rejected the direct assignment of integrated grid facilities even if those facilities would not have been installed but for a particular request for service."[36] The Commission articulated this policy in both its SMD NOPR and its Generator Interconnection proposed rule and Final Rule.[37] In the SMD NOPR the Commission stated:

---

[35] Similarly, the SMD NOPR contemplates a single regional rate for Network Access Service; See Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 FR 55,541 (Aug. 29, 2002), FERC Stats. & Regs. ¶ 32,563 (2002) at P 170 ("SMD NOPR").

[36] See Entergy Mississippi Inc., 102 FERC ¶ 61,105, at P 8 (2003). The Entergy order was issued well after the SMD NOPR but reiterated the Commission's established policy that applies to all network upgrades and not just in the generator interconnection context ("We have not allowed network facilities to be treated as sole use facilities or be directly assigned. Even if a customer causes the addition of a grid facility, the addition is a system expansion *used by and benefiting all users due to the integrated nature of the grid*.") Entergy P 8. (Emphasis added.) See also Public Service Company of Colorado, 59 FERC ¶ 61,311 (1992), reh'g denied, 62 FERC ¶ 61,013 (1993); Consumers Energy Co. 96 FERC ¶ 61,132, at 61,561 (2001) ("The Commission has long held that the integrated grid is a cohesive network whose expansion benefits all users of the grid."); accord e.g., San Diego Gas & Electric Co., 98 FERC ¶ 61,322, at 62,407-408 (2002) (system, or network, upgrades provide system-wide benefits due to the integrated nature of the system, and their costs thus should be borne by all system users).

[37] See, e.g,, SMD NOPR at P 193; Standardization of Generator Interconnection Agreements and Procedures, Notice of Proposed Rulemaking, 67 FR 22,250 (May 2, 2002), FERC Stats. & Regs. ¶ 35,560 at pp. 20-21 (2002)("Generator Interconnection NOPR").

> The Commission's pricing policy for network upgrades, whether for reliability or economic reasons, has traditionally favored "rolled in" pricing, where all users pay an administratively determined share of new facilities. *This policy was based on the rationale that the transmission grid is a single piece of equipment such that system expansions are used by and benefit all users due to the integrated nature of the grid.* This method forms the basis of the pricing proposal in the Generator Interconnection proposed rule.[38] (Emphasis added.)

This long-established transmission cost allocation policy, and its underlying rationale, is especially suitable for network upgrades to a tightly interconnected transmission system such as the New England grid. The TCA Proposal is squarely in line with this policy. While the SMD NOPR signaled a desire to have participant funding for those upgrades that are susceptible to a precise matching of costs and particular beneficiaries, RBUs are not so susceptible. Instead, they are the kind of system expansions that provide system-wide benefits and thus should receive regional cost support.

3. The TCA Amendments are consistent with the Commission's policy to promote the building of needed transmission infrastructure to support robust markets.

In the SMD NOPR the Commission recognized the need for transmission expansion and stated its goal in transmission cost allocation was "to remove any cost recovery impediments to transmission expansion *so that needed upgrades get built now*."[39] (Emphasis added.) The TCA Amendments, applied in tandem with the RTEP process, accomplish that goal. The RTEP process identifies needed upgrades, gives the market an opportunity to respond, and when the market does not respond, it gets needed upgrades built. The default RBU mechanism removes the cost recovery impediments to expanding the network for the benefit of all users. Establishing a default cost allocation mechanism along with a regional planning process is critical in light of the markets' inability to respond consistently with transmission-based solutions.[40]

---

[38] Similarly, Order No. 2003 continues this long-established pricing policy and states that network upgrades benefit all users of the transmission system without a need for a case-by-case determination of who benefits from any particular upgrade. <u>See</u> Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, _____ FR _____ (August __, 2003), FERC Stats. & Regs. ¶ _____ (2003), 104 FERC ¶ 61,103 at PP 65-66, 693-703 (2003) ("Order 2003").

[39] SMD NOPR at P 196. Additionally, the need for new transmission infrastructure was identified by the Department of Energy as an important national interest in its National Transmission Grid Study published in May 2002.

[40] <u>See, e.g.</u>, SMD NOPR at P 350 ("recogniz[ing] that private investment decisions may not be fully adequate in all cases [to provide needed transmission] because of eminent domain and the possibility that private benefits of investment could be significantly less than social benefits.").

E. The TCA Amendments are consistent with the Consensus Principles developed through the New England stakeholder process.

As described in Section II of this letter, the ISO-NE led stakeholder process identified six principles to guide the development of an appropriate transmission cost allocation proposal. The Consensus Principles are enumerated below, with an explanation of how the TCA Amendments are consistent with them.

1. The transmission cost allocation method should consider the multiple benefits of the facility over its full life.

This principle recognizes that during the 40 or more years life of a network transmission facility it will provide both economic and reliability benefits and will provide those benefits to beneficiaries that will change over time. Beneficiaries can change by the minute, commitment period, season, power year, etc. as load, fuel costs, available supply and transmission resources, and interconnections with neighboring control areas change over time. In the past seven years since the beginning of the regional NEPOOL Tariff, New England has experienced some dramatic changes to the usage and beneficiaries of network transmission facilities. These changes are caused by many different factors, including the following: the shutdown and subsequent reactivation of certain nuclear units in Connecticut, the addition of 10,000 megawatts of new generation in four years, record heat waves and drought conditions, ice storms, natural gas curtailments and price swings, a booming economy and a deep recession, and the ongoing evolution of the wholesale power markets. Continuing change and changing beneficiaries should be expected.

The TCA Amendments anticipate this dynamic state of the regional transmission network and allocate costs for RBUs accordingly to all regional users of the network, based on the premise that they either benefit now or will benefit over the life of the RBU.

2. The transmission cost allocation method should encourage proper investment.

This principle recognizes that to ensure protection of reliability and success of the wholesale markets in New England, there must be adequate transmission capacity to get generation to the load in a reliable and efficient manner. The RTEP process and the TCA Amendments look first to private investment to meet system needs. Such a market-based response is likely to reduce the need for transmission infrastructure but not eliminate the need. When the need for such infrastructure persists after the market has had an opportunity to respond, a well-designed default cost allocation, as is contained in the TCA Amendments, makes it easier to get that transmission infrastructure built.

3. The transmission cost allocation method should send appropriate price signals relative to the SMD market.

This principle recognizes that the cost allocation method should work together with SMD to allow locational marginal pricing to identify the need and opportunity for market solutions to congestion. The TCA Amendments do this in conjunction with the RTEP process. Market opportunities are identified through that process, and the market is given the first chance to respond. Only after the market has failed to meet a need on the system does the RBU regional cost support mechanism activate.

4. The transmission cost allocation method should be perceived as fair and equitable to transmission customers.

This principle recognizes that the cost allocation method should allocate costs to those who benefit or cause the costs, while allowing for voluntary transmission funding. The TCA Amendments recognize that all load benefits from RBUs over the life of those facilities and allocate those costs accordingly. Similarly, they allocate the costs for LBUs and Localized Costs to the local load that benefits. In addition, they allow for voluntarily-funded transmission in the form of Elective Transmission Upgrades and Merchant Transmission Facilities. Thus, the TCA Amendments are perceived as fair and equitable to transmission customers. Indeed, the interests of transmission customers in New England are represented generally by Publicly-Owned Entities, the End Users, and some transmission owners. As demonstrated in Attachment 7, all of these sectors supported the Amendments by wide margins.

5. The transmission cost allocation method should provide price certainty to investors and customers.

This principle recognizes that relative certainty about how costs will be recovered over the life of new transmission facilities is of paramount importance at the time investment decisions are being made. In an environment of cost recovery uncertainty, investment in needed transmission is likely to be sorely lacking, resulting in adverse consequences for reliability and markets. As explained above, a case-by-case upgrade study method that tries to directly match beneficiaries and cost on a sub-regional basis will either require a changing cost allocation over time or will involve a significant free rider problem. In addition, litigation challenges to the cost allocation of each upgrade would be more likely. Such an environment of uncertainty will undoubtedly discourage investment.

6. The transmission cost allocation method should provide for ease of implementation.

This principle recognizes that ease of implementation is critical to getting needed transmission built. Individual studies of transmission projects with a case-by-case determination of beneficiaries and cost assignment that will change over time, is likely to overwhelm administrative resources and result in more litigation than new transmission. As discussed above, the bright line RBU/LBU test that is not only equitable but easily implementable.

F. The TCA Amendments are not intended to re-institute integrated resource management.

During the stakeholder workshops, a number of stakeholders argued that, whatever default cost allocation methodology was devised for transmission upgrades, must be applied to other resources. In other words, these stakeholders asserted that, if regional cost sharing was appropriate for 115kV+ transmission facilities that provided parallel path capability, then regulated regional cost sharing would be appropriate for a generator or demand response solution that might also address the identified needs. For technical and policy reasons, those arguments did not prevail.

The premise for integrated resource planning and resource parity is that all resources (generation, demand-side management and transmission) provide the same benefits to the power grid and that market based resources should be re-regulated and provided with regional cost support in the event that those market based resources do not respond to market signals. This premise was rejected in favor of competitive markets for supply and is not supported by the fact that different resources have different electrical characteristics, providing different capabilities to the bulk power grid. At the heart of this debate is the issue of whether regulated transmission upgrades are considered to be in competition with market solutions. They are not. Transmission and generation are fundamentally different. Generation and demand resources supply (or limit) the energy customer's desire. Transmission facilities, on the other hand, allow this energy to be delivered regionally, thus enabling more efficient use of existing resources and enabling robust competition among existing and new supply resources. Only when the market fails to provide a response to an identified need would the TCA Amendments apply to needed transmission facilities.

To the extent that stakeholders raised concerns about the planning process and market rules, and the dynamic planning processes and market rules created for investment in market-based resources (*e.g.*, generation, demand response, merchant transmission), ISO-NE directed those stakeholders to planning and market rules forums for appropriate tariff and market rule changes.[41] Ultimately, the concerns and questions that stakeholders may have about proper incentives for market resources and appropriate planning processes are not relevant to determining the appropriate default cost allocation for cost-based, regulated transmission upgrades.

V. <u>Description of Amendments</u>

[41] It should be noted that in the context of the planning workshops ISO-NE held subsequent to the Stakeholder Workshop on transmission cost allocation, and in response to the concerns expressed by Stakeholders, ISO-NE plans on proposing amendments to the regional transmission expansion process in its RTO filing this fall.

Schedule 12 "Transmission Cost Allocation On and After January 1, 2004" (which replaces the existing Schedule 12 on January 1, 2004), provides the cost allocation for each type of upgrade, modification or addition to the transmission system in New England. Schedule 12 describes how Transmission Upgrades will be categorized, and the process for allocating costs for the following Upgrade categories: Generator Interconnection Related Upgrades; Elective Transmission Upgrades; NEMA Upgrades; RTEP02 Upgrades; Regional Benefit Upgrades; Local Benefit Upgrades; and Localized Costs. The treatment of costs for Merchant Transmission Facilities is also included as part of Schedule 12.

Schedule 12A, "NEMA Upgrades", is a new Schedule that identifies NEMA upgrades. Schedule 12B, "RTEP02 Upgrades", provides a list and general description of all projects classified as RTEP02 Upgrades. Schedule 12C, "Determination of Localized Costs On and After January 1, 2004", describes the procedures that will be used by ISO-NE to determine Localized Costs for RBUs and RTEP02 Upgrades on or after January 1, 2004. As noted above, the review process governed by Schedule 12C replaces the current review process administered by the NEPOOL Reliability Committee and Participant Committee pursuant to Section 15.5 of the Restated NEPOOL Agreement.

Section 51 of the NEPOOL Tariff is being revised to clarify that ISO-NE may periodically update the NEPOOL Transmission Plan and that there will be interim ISO-NE approvals and annual approvals by the ISO-NE Board of Directors, each of which will have the same effect with regard to cost reimbursement. Section 1 and other miscellaneous sections of the NEPOOL Tariff are also being amended by adding, modifying and deleting certain definitions and other provisions that need to be conformed to the substance of the TCA Amendments (the definitional changes and the miscellaneous conforming changes are all listed in the 100th Agreement, included with this letter as Attachment 1).[42]

Finally, a new Section 15.1A is being added to the Restated NEPOOL Agreement. Section 15.1A provides clarifies how to determine whether those transmission facilities that are upgrades, modifications or additions to the NEPOOL Transmission System on and after January 1, 2004 will be classified as PTF.

---

[42] NEPOOL notes that this filing contains an errata change that was discovered during the process of drafting the TCA Amendments. The definition for Generator Interconnection Related Upgrade is being added to the Tariff (the text of the definition is included as part of Attachment 3 to this letter). This definition was approved by the Participants Committee as an amendment to the Tariff pursuant to the Fifty-Eighth Agreement, but inadvertently was dropped from the Tariff when the so-called CMS/MSS changes were dismissed as moot, ISO New England, 96 FERC ¶ 61,361 (2000). This term is used throughout the Tariff, as well as in the TCA Amendments, and therefore must be included in Section 1 as a defined term.

VI. Additional Supporting Information

The NEPOOL Participants Committee submits the following information pursuant to Section 205 of the Federal Power Act and Section 35.13, et seq. of the Code of Federal Regulations:

35.13(b)(1) - Materials included herewith are as follows:

- This transmittal letter;
- The One-Hundredth Agreement Amending New England Power Pool Agreement (Attachment 1);
- A revised sheet of the Restated NEPOOL Agreement marked to show the changes effected by the 100th Agreement (Attachment 2);
- Revised sheets of the NEPOOL Tariff (Attachment 3);
- Revised sheets of the NEPOOL Tariff marked to show changes effected by the 100th Agreement (Attachment 4);
- Stakeholder Workshop(s) attendance lists (Attachment 5);
- Straw Proposals for Default Transmission Cost Allocation Mechanisms, January 13, 2003 (Attachment 6);
- Tabulation of the votes pertaining to the 100th Agreement (Attachment 7);
- Maine/Rhode Island Settlement Proposal (Attachment 8);
- TCA Flowchart (Attachment 9);
- A list of NEPOOL Participants Committee members and alternates and non-Participant Transmission Customers (Attachment 10);
- A list of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent (Attachment 11);
- A draft form of notice, suitable for publication in the Federal Register (Attachment 12), and a diskette containing this form of notice.

35.13(b)(2) –NEPOOL and ISO-NE request that the Commission accept the changes proposed to the New England Power Pool Agreement to become effective October 1, 2003.

35.13(b)(3) - Attachment 10 of this transmittal letter shows the names and addresses of all Participants Committee members and alternates, which include all the electric utilities rendering or receiving services under the Restated NEPOOL Agreement, as well as each of the independent power producers, power marketers, power brokers, load aggregators, customer-owned utility systems and end users that are currently Participants in NEPOOL. All Participants have been furnished a copy of this filing, together with this transmittal letter and the accompanying materials.[43] This transmittal letter and the accompanying materials have also been sent to the governors and the electric utility regulatory agencies for the six New England states which comprise the NEPOOL Control Area, and to the New England Conference of Public Utilities Commissioners, Inc. The names and addresses of these governors and regulatory agencies are shown in Attachment 11. In accordance with Commission rules and practice, there is no need for the entities identified in Attachments 10 and 11 to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) - A description of the materials submitted pursuant to this filing is contained in this transmittal letter.

35.13(b)(5) - The reasons for this filing are discussed in Sections II-IV of this transmittal letter.

35.13(b)(6) – Pursuant to NEPOOL governance procedures, the NEPOOL Participants Committee is required to approve changes to the New England Power Pool Agreement by a vote of at least 66 2/3 percent. The NEPOOL Participants Committee approved the changes contained in this filing by a vote of 78%.

35.13(b)(7) - The NEPOOL Participants Committee has no knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(b)(8) - Submitted as Attachment 12 to this transmittal letter is a draft form of notice concerning this filing that is suitable for publication in the Federal Register in accordance with Section 35.8 of the Commission's Regulations. A diskette containing this form of notice is also enclosed.

35.13(c)(1) - As described above, the changes contained in the 100th Agreement, modify the NEPOOL Tariff with respect to transmission cost allocation. No reliable estimate of revenue impact from these changes is possible.

[43] Pursuant to changes to Section 21.13(e) of the Restated NEPOOL Agreement, which was accepted by the Commission in New England Power Pool, 90 FERC ¶ 61,019 (2000), NEPOOL Participants are being served electronically rather that by hard copy.

35.13(c)(2) - The Participants do not jointly provide services under other rate schedules that are similar to the wholesale for resale and transmission services jointly provided by them under the Restated NEPOOL Agreement.

35.13(c)(3) – No specifically assignable facilities have been or will be installed or modified in order to supply service under the proposed changes included herein.

Correspondence and communications regarding this filing should be addressed to the persons listed below:

Rose Psyh, Vice-Chair
Tariff Committee
The United Illuminating Company
157 Church Street, MS 1-15D
P.O. Box 1564
New Haven, CT 06506-0901
Tel: (203) 499-2031
Fax: (203) 499-3625
E-mail:rose.pysh@uinet.com

David T. Doot
Eric K. Runge
Day, Berry & Howard LLP
CityPlace I
Hartford, CT 06103
Tel: (860) 275-0102
Fax: (860) 275-0343
E-mail: dtdoot@dbh.com
ekrunge@dbh.com

And to ISO-NE as follows:

Kathleen Carrigan
Matthew Goldberg
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
Tel: (413) 540-4559
Fax: (413) 535-4379
E-mail: kcarrigan@iso-ne.com
mgoldberg@iso-ne.com

Howard H. Shafferman
Ballard Spahr Andrews & Ingersoll, LLP
601 13th Street, N.W. Tenth Floor
Washington, DC 20005
Tel: (202) 661-2218
Fax: (202) 661-2299
E-mail: hhs@ballardspahr.com

Please acknowledge receipt of the foregoing by date-stamping the enclosed extra copy of this filing and returning it to the courier delivering this filing.

Respectfully submitted,
New England Power Pool Participants Committee

By: David T. Doot
Its Secretary

ISO New England Inc.

By: Kathleen A. Carrigan
Its General Counsel

cc: Entities identified in Attachments 10 and 11.

51242890.6

ATTACHMENT 1

ONE HUNDREDTH AGREEMENT AMENDING
NEW ENGLAND POWER POOL AGREEMENT
(TRANSMISSION COST ALLOCATION AGREEMENT)

THIS ONE HUNDREDTH AGREEMENT AMENDING NEW ENGLAND POWER POOL AGREEMENT, dated as of June 25, 2003 ("One Hundredth Agreement"), amends the New England Power Pool Agreement (the "NEPOOL Agreement"), as amended.

WHEREAS, the NEPOOL Agreement as in effect on December 1, 1996 was amended and restated by the Thirty-Third Agreement Amending New England Power Pool Agreement dated as of December 1, 1996 (the "Thirty-Third Agreement") in the form of the Restated New England Power Pool Agreement ("Restated NEPOOL Agreement") attached to the Thirty-Third Agreement as Exhibit A thereto, and the Thirty-Third Agreement also provided for the NEPOOL Open Access Transmission Tariff (the "NEPOOL Tariff") which is Attachment B to the Restated NEPOOL Agreement; and

WHEREAS, the Restated NEPOOL Agreement and the NEPOOL Tariff have subsequently been amended numerous times, the most recent amendment dated as of February 14, 2003; and

WHEREAS, the Participants desire to amend the Restated NEPOOL Agreement, including the NEPOOL Tariff, to reflect the revisions detailed herein.

NOW, THEREFORE, upon approval of this One Hundredth Agreement by the NEPOOL Participants Committee in accordance with the procedures set forth in the NEPOOL Agreement, the Participants agree as follows.

SECTION 1

AMENDMENT TO RESTATED NEPOOL AGREEMENT

1.1 Addition of Section 15.1A. A new Section 15.1A is added immediately following Section 15.1 to read as follows:

Of those transmission facilities that are upgrades, modifications or additions to the NEPOOL Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section 15.1 or Section 15.1A of this Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the criteria specified in Section 15.1 or Section 15.1A of this Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England), shall remain classified as PTF for all purposes under this Agreement and the Tariff.

SECTION 2

AMENDMENTS TO NEPOOL TARIFF

2.1 Amendment to Definition of Economic Upgrade. The definition of Economic Upgrade is amended to read as follows:

Economic Upgrade: Those additions and upgrades that are not related to the interconnection of a generator, and, in the System Operator'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 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.

2.2 Amendment to Definition of Elective Transmission Upgrade. The definition of Elective Transmission Upgrade is amended to read as follows:

Elective Transmission Upgrade: is a Transmission Upgrade that is participant funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Economic Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the System Operator in accordance with Section 50.2 on a date after the addition or modification already has been otherwise identified in the current NEPOOL Transmission Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

2.3 Amendment to Definition of NEMA or "Northeast Massachusetts" Upgrade: The Section 1 definition of NEMA or "Northeast Massachusetts" Upgrade is amended by adding the following sentence to the end thereof:

The list of NEMA Upgrades is contained in Schedule 12A of this Tariff.

2.4 Delete Definition of Network Upgrades: The definition of Network Upgrades is deleted in its entirety.

2.5 Amendment to Definition of System Impact Study: The definition of System Impact Study is amended by inserting the word "Transmission" between "Elective" and "Upgrade".

2.6 Additional Definitions. Section 1 is amended by adding in the appropriate alphabetical order and assigning the appropriate section number to the following definitions:

Localized Costs: the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the System Operator 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 System Operator will consider, in accordance with Schedule 12C of this Tariff, 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, efficiency and reliability of the proposed Transmission Upgrade. Prior to any recovery of costs under this Tariff associated with a RTEP02 Upgrade or a Regional Benefit Upgrade, the System Operator, 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 System Operator shall identify them in the NEPOOL Transmission Plan.

Local Benefit Upgrade(s) ("LBUs"): a 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 Section 15.1 of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England).

Regional Benefit Upgrade(s) ("RBU(s)"): a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in Section 15.1 of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England); and (iii) is included in the NEPOOL Transmission Plan as either a Reliability Upgrade or an Economic Upgrade identified as needed pursuant to Section 51 of this Tariff. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of this Tariff (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115 kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in Section 15.1 or Section 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England).

RTEP02 Upgrade(s): a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by the System Operator's Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by the System Operator. The RTEP02 Upgrades are listed in Schedule 12B of this Tariff.

Transmission Upgrade(s): an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of this Tariff governing rates and service on the PTF on or after January 1, 2004. The categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of this Tariff.

2.7 Amendment to Sections 5 and 33.2(i). The final sentence in both Section 5 and Section 32.1(i), are amended by inserting the word "Transmission" between "Elective" and "Upgrade".

2.8 Amendment to Sections 44.4 and 46. Sections 44.4 and 46 are amended by substituting the phrase "upgrades, modifications or additions to the PTF" in place of the term "Network Upgrades" at each occurrence.

2.9 Amendment to Section 51.4(c). Section 51.4(c) is amended to read as follows:

An Upgrade may be approved for addition to the NEPOOL Transmission Plan by the System Operator at any time in a given year and in doing so the System Operator may consult with and consider input from the Transmission Expansion Advisory Committee, within the scope of its respective functions as specified in subsection (b) of Section 51.2, and the Reliability Committee within the scope of its function as specified in Section 8.4(a) of the Agreement. Similarly, an Upgrade may be approved for removal from the NEPOOL Transmission Plan by the System Operator at any time in a given year if the market responds by proposing alternative generation projects, Merchant Transmission Facilities in accordance with Section 51.8, or demand-side projects, or other circumstances arise such that the need for the Upgrade no longer exists, and in doing so the System Operator may consult with and consider input from the Transmission Expansion Advisory Committee, within the scope of its functions as specified in subsection (b) of Section 51.2, and the Reliability Committee within the scope of its function as specified in Section 8.4(a) of the Agreement; provided that the entity responsible for the construction of the Upgrade is reimbursed for any costs prudently incurred or prudently committed to be incurred in connection with the planning, preparation for construction, and/or construction of the Upgrades removed from the Plan. All Upgrades approved for addition or removal in such interim Plans during this planning process must meet the requirements of subsection (a) of Section 51.3. In the event that the estimated cost of a proposed Upgrade exceeds $20 million (which threshold amount shall be reviewed annually by the System Operator and reset as it reasonably deems appropriate), a member of a subcommittee of the System Operator's Board will attend such meeting at which the ISO will seek the Reliability Committee's advice on the inclusion of the proposed Upgrade into the NEPOOL Transmission Plan. An approval of the interim Plan by the System Operator made pursuant to this subsection (c) shall have the same effect with regard to cost reimbursement and with regard to inclusion or removal of an Upgrade from the Plan as an approval of the Plan made by the System Operator's Board of Directors pursuant to Section 51.4(i) of this Tariff.

2.10 Amendment to Section 51.4(f). Section 51.4(f) is amended by inserting the phrase "Committee and the Reliability" before the term "Committee" in the first sentence, by replacing the text following the term "Committees" in the third sentence with the phrase "the Reliability Committee and input from those committees shall be received and considered by the System Operator in preparing and revising subsequent plan approvals" after the term "Committees", by replacing the phrase "a final draft of any proposed" with the phrase "an interim" in the fourth sentence, and by replacing the term "draft" with the phrase "NEPOOL Transmission Plan" at the end of the fourth sentence.

2.11 Amendment to Section 51.4(g). The second sentence of Section 51.4(g) is amended by replacing the term "Congestion Costs" with the phrase "bulk power system costs to load system-wide".

2.12 Amendment to Section 51.4(h). Section 51.4(h) is amended by deleting the phrase "recommended draft of a" at the start of the second sentence, by replacing the second occurrence of the term "recommended" with the phrase "NEPOOL Transmission" in the second sentence, by replacing the term "draft" with the term "interim" in the third sentence, and by replacing the second occurrence of the term "recommended" with the term "interim" in the third sentence.

2.13 Amendment to Section 51.4(i). Section 51.4(i) is amended by replacing the phrase "A draft of a recommended" with the phrase "The interim" at the start of the first sentence, by replacing the term "draft" with the term "Plan" in the second sentence, by replacing the phrase "In other years, the draft may be only an update to a prior approved" with the phrase "The interim" in the third sentence, by striking the period at the end of the third sentence and the phrase "The draft" at the start of the fourth sentence to combine the two, by replacing the term "recommended" with the term "interim" in the fifth sentence, by inserting the term "interim" after the phrase "modify the" in the fifth sentence, and by replacing the term "recommendation" with the phrase "interim Plan" in the fifth sentence.

2.14 Amendment to Schedule 12 (Reliability Upgrade, Economic Upgrade and Elective Transmission Upgrade Costs). Schedule 12 is amended by inserting the following new introductory note immediately preceding Section (1):

Note: This Schedule 12 shall remain in effect through and including December 31, 2003, to be superseded as hereinafter provided.

2.15 Revised Schedule 12 (Transmission Cost Allocation On and After January 1, 2004). A revised Schedule 12, which shall supersede in its entirety the version of Schedule 12 that is in effect as of the date hereof, is added to read as set forth in Attachment 1 to this Agreement.

2.16 New Schedule 12A (NEMA Upgrades). A new Schedule 12A is added to read as set forth in Appendix B hereto.

2.17 New Schedule 12B (RTEP02 Upgrades). A new Schedule 12B is added to read as set forth in Appendix C hereto.

2.18 New Schedule 12C (Determination of Localized Costs On and After January 1, 2004). A new Schedule 12C is added to read as set forth in Appendix D hereto.

SECTION 3

AMENDMENT TO ATTACHMENT F IMPLEMENTATION RULE

3.1 Amendment to Appendix A to Attachment F Implementation Rule. Appendix A to the Attachment F Implementation Rule is amended by inserting the following text immediately preceding Section A thereto:

> The following provision shall apply to Sections A, B and C below:
>
> Of those transmission facilities that are upgrades, modifications or additions to the NEPOOL Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section 15.1 of the Agreement (or the equivalent of such Section 15.1 as may be adopted under successor documents governing the regional transmission system in New England) shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in Sections 15.1 or 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England), shall remain classified as PTF for all purposes under the Agreement and this Tariff.

SECTION 4
MISCELLANEOUS

4.1 This One Hundredth Agreement shall become effective sixty days from the date of its filing with the Commission, or on such other date as the Commission shall provide.

4.2 Terms used in this One Hundredth Agreement that are not defined herein shall have the meanings ascribed to them in the NEPOOL Agreement.

SCHEDULE 12

Transmission Cost Allocation On and After January 1, 2004

On January 1, 2004, this Schedule 12 shall supersede in its entirety the version of Schedule 12 that is in effect as of June 25, 2003 ("Current Schedule 12"). Current Schedule 12 shall remain in effect through and including December 31, 2003. This Schedule 12 describes the cost allocation treatment of upgrades, modifications or additions to the transmission system in New England on and after January 1, 2004. Nothing in this Schedule 12 shall eliminate the PTF status of transmission facilities that were PTF on December 31, 2003; and any upgrades to such facilities that continue to meet the definition of PTF specified in Section 15.1 or Section 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) shall be classified as PTF for all purposes under the Agreement and this Tariff.

A. Process for Categorizing Upgrades for Cost Allocation:

Upgrades, modifications or additions to the NEPOOL Transmission System shall be categorized by the System Operator, with advisory input from the Reliability Committee and the Transmission Expansion Advisory Committee, as appropriate. A list of categorized Transmission Upgrades shall be made part of each annual and interim NEPOOL Transmission Plan, subject to the provisions of Section 51 of this Tariff.

B. Transmission Cost Allocation By Category:

1. Generator Interconnection Related Upgrades:

The cost for all Generator Interconnection Related Upgrades shall be allocated pursuant to Schedule 11 of this Tariff.

2. Elective Transmission Upgrades:

The cost for all Elective Transmission Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this Tariff, but shall be allocated solely to the entity or entities volunteering to make and pay for such Elective Transmission Upgrades.

3. NEMA Upgrades:

The cost for all NEMA Upgrades shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades continue to meet the definition of PTF under either Section 15.1 or 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) and allocated to Transmission Customers taking service under this Tariff.

4. RTEP02 Upgrades:

The costs for all RTEP02 Upgrades placed in service on or before December 20, 2007, shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades continue to meet the definition of PTF under either Section 15.1 or 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) and allocated to Transmission Customers taking service under this Tariff.

5. Regional Benefit Upgrades:

The cost for all Regional Benefit Upgrades, as well as all transmission facilities that were PTF as of December 31, 2003 and upgrades to such facilities that meet the definition of PTF under either Section 15.1 or 15.1A (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England), shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades and such existing PTF continue to meet the definition of PTF under either Section 15.1 or 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) and allocated to Transmission Customers taking service under this Tariff. Economic Upgrades that are not RBUs shall not be included in the Pool-Supported PTF Costs recoverable under this Tariff.

6. Local Benefit Upgrades:

The cost for Local Benefit Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this Tariff.

7. Localized Costs:

Localized Costs shall not be included in the Pool-Supported PTF costs recoverable under this Tariff, but instead the responsibility for Localized Costs related to any RTEP02 Upgrades and any Regional Benefit Upgrades shall be the responsibility of the entity or entities causing or subject to such Localized Costs. The System Operator, in accordance with Schedule 12C of this Tariff, shall review RTEP02 Upgrades and Regional Benefit Upgrades and identify any Localized Costs associated with them.

C. Merchant Transmission Facilities Cost Allocation

The cost of all Merchant Transmission Facilities, including the cost of Transmission Upgrades required to interconnect the Merchant Transmission Facilities to the PTF, shall be the responsibility of the developer of the Merchant Transmission Facilities, and shall not be included in the Pool-Supported PTF costs recoverable under this Tariff.

SCHEDULE 12A

NEMA Upgrades

A "Northeast Massachusetts Upgrade" is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section 18.4 of the Restated NEPOOL Agreement; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. The aggregate capital costs of the Northeast Massachusetts Upgrades which qualify as Pool-Supported PTF costs shall not exceed $35,000,000. A general description of the projects which constitute the NEMA Upgrades is provided in the list below.

1. Framingham 230/115kV autotransformer and breaker replacement
2. Upgrade Framingham to West Medway 230 kV line (240-601)
3. Add Mystic 345kV breaker #101S
4. West Walpole 345/115kV autotransformer and breaker replacement
5. Rebuild Speen Street to Sudbury 115kV line (342-507) and replace breakers at both ends
6. Waltham 230/115kV autotransformer and breaker replacement
7. Upgrade Waltham to West Medway 230 kV line (282-602)
8. Upgrade Framingham to Speen Street 115kV line (433-507) and replace breakers at Framingham
9. Add a third Waltham 115kV phase shifting transformer
10. Upgrade Sherborn 115kV station equipment
11. Merrimack (New Hampshire) 230/115kV autotransformer replacement

SCHEDULE 12B

RTEP02 Upgrades

Following is a general description of projects which constitute the RTEP02 Upgrades.

Project Description
New Brunswick – New England Tie Performance Enhancement • Series compensation
MEPCO Special Protection Systems Alternative • Alternative 1: Decommission existing SPS and install new direct logic sensing Transfer Trip SPS. • Alternative 2: Extend time delay on existing flow based SPS and install new direct logic sensing Transfer Trip SPS. • Alternative 3: Decommission existing SPS and install new direct logic sensing Transfer Trip SPS with fault discrimination.
Bangor Hydro Electric Down East Transmission Reliability Improvement • New transmission path between Rebel Hill and the Epping/Washington County area • Reconfiguration of existing facilities.
CMP Autotransformer-Outage Reliability Improvement • Review/mitigation of 120°F sag limits. • Mitigation of line overloading that limits select pockets of generation. • Mitigation of low voltages that may be improved with implementation of the new Maine Voltage Operating Guide and capacitor bank additions.
Maine and New Hampshire Voltage Enhancements • Install 24 MVAR capacitors at Sanford 115 kV substation • Add 50 MVARs of capacitors at Ocean Road and Madbury • Add 60 MVARs of capacitors at Three Rivers • Add 170 MVARs of capacitors at Maxcys and western Maine
Maine – New Hampshire Transfer Capability Short Term Enhancements • Schiller to Bolt Hill 115 kV N133 line upgrade • Quaker Hill to Three Rivers 115 kV 197 line upgrade • Maguire to Three Rivers 115 kV 250 line upgrade • Alternate project: Southern Maine substation re-configuration or series reactor

Project Description
Requirements for Closing PSNH's Y138 Line – Saco Valley to White Lake • Saco Valley 115 kV breaker additions • 120 MVAR of shunt reactive compensation is needed between the Maine and New Hampshire ends of the transmission system • Series reactor overload mitigation system is needed on the New Hampshire end of the Beebe to White Lake 115 kV B112 line • Alternative: Beebe 115kV phase shifter • Beebe substation terminal equipment upgrades on B112 line to change out circuit breaker, disconnect switches, bus work and secondary equipment • Re-rate 28 miles of 115 kV Section 214 transmission line from Kimball Road to Harrison and Lovell in Maine • White Lake 115kV capacitor

Southern New Hampshire Reinforcements
• Rebuild Scobie 115 kV substation to breaker and a half arrangement
• Re-conductor Deerfield to Garvins 115 kV G146 line
• Add a second 345/115 kV 400 MVA autotransformer at Scobie substation
• Add a second 345/115 kV 400 MVA autotransformer at Deerfield substation
• Add three 50 MVAR capacitor banks at the Deerfield 115 kV substation
• Deerfield dynamic voltage control
• New 115 kV line from Reeds Ferry – Huse Road
• Upgrade Greggs 115 kV substation
• Upgrade Merrimack 115 kV substation
• Add Amherst 345 kV 4 – breaker ring bus
• Add six 50 MVAR capacitor banks at the Scobie 115 kV substation
• Re-terminate Deerfield autotransformer and/or second breaker
• Re-conductor two 115 kV circuits from Schiller – Scobie (U181/H141 and E194/R193)
• Alternatives considered:
  o Newington 345/115 kV autotransformer
  o Coburn Road 345/115 kV autotransformer
  o Rebuilding the 115 kV Deerfield – Laconia D140 line

Northwest Vermont Near-term Voltage Reinforcement • Essex Capacitors, two 24.75 MVAR 115 kV banks
Rutland Reliability Project • Energize existing Coolidge-West Rutland line at 345 kV • Add two West Rutland 345/115 kV transformers • Add three 345 kV circuit breakers at Coolidge • Add three 115 kV circuit breakers at West Rutland • Add two 24.75 MVAR 115 kV capacitor banks at Coolidge

Project Description
Northwest Vermont Reliability Project • New Haven-West Rutland 345 kV line and 345/115 kV New Haven substation with 115 kV ring bus • Granite 230 kV PAR, 25 MVAR capacitor bank and breaker additions • 150 MVAR STATCOM at Granite • Blissville 115 kV PAR • New Haven-Vergennes-Queen City 115 kV line • Hartford 115 kV breaker – Add an existing 115 kV motorized SCADA controlled disconnect switch with a circuit breaker at Hartford substation on the line toward the Chelsea substation • Granite to Middlesex 230 kV • Addition of 230/115 kV and 345/115 kV autotransformers • Addition of breakers and shunt devices
Vermont Northern Loop Project • New Irasburg – Newport 115 kV line ("northern loop") operated synchronous with VELCO (7 miles of new 115/46kV double circuit construction) • New 115 kV breaker at St. Johnsbury • Two new 115 kV breakers at Irasburg • New five breaker 115 kV ring bus at Highgate • St Albans Line reconfiguration and substation upgrade-Reconfigure St Albans lines and breakers to replace the single 115kV tap line with two "in and out" lines

Monadnock Regional Reinforcement
• Addition of switched capacitor banks at Chestnut Hill 115 kV bus
• Potential alternatives:
    o New Fitzwilliam 345/115 kV substation north of Flagg Pond tapped onto the Scobie Pond – Vermont Yankee 345 kV 379 line and separation of the existing lines between Flagg Pond and Pratts Junction.
    o (Third) Pratts Junction to Flagg Pond 115 kV line

Greater Metro-West Transmission Supply Study • Install tie breaker and second radial Northborough – Hudson 115 kV line • Re-conductor Woodside-Northborough / Fitch Rd 69 kV W-23 line • Millbury 115 kV 63 MVAR Capacitor Bank • Northborough 115 kV 54 MVAR Capacitor Bank • Fitch Road – Rebuild 69 kV station • Re-conductor Fitch Rd to Pratts Junction 69 kV N40 line • Install Woodside 69 kV breaker
Central Massachusetts Reliability Reinforcement • Re-conductor V174 Carpenter Hill to Millbury 115 kV • Install new 345/115 kV autotransformer in Central Massachusetts (e.g. Pratts Junction, Millbury) • Install second Wachusett 115/69 kV autotransformer

Project Description
• Pratts Junction 115/69/13.8 kV transformer replacement
Springfield/Western Massachusetts Reliability Reinforcements • Improve sag clearances on the 115 kV Blandford – Pleasant 1421 line • Pleasant 115 kV capacitor bank • As determined by study
NEMA/Boston Short-term Reliability Reinforcements Potential North Shore upgrades include: • B154N/C155N Ward Hill to Salem Harbor 115 kV line upgrades (re-sag/re-conductor) • Second Ward Hill 345/115 kV transformer • Completion of the Golden Hills 345 kV ring bus • Split up switching of Mystic-Golden Hills 345 kV cables (348X+Y) • F-158N and Q-169 Golden Hills to Everett and to Lynn 115 kV line upgrades • Other 115 kV line upgrades
NEMA/Boston Long-term Reliability Reinforcements Potential upgrades include: • Mystic-K Street-Kingston 345 kV loop • Other 345 kV and/or 115 kV line upgrades • Build 345 kV line from Scobie to Tewksbury
Norwood Municipal Light Department Reliability Reinforcements • Install two new 115 kV underground lines to Norwood's new Ellis Avenue substation (2.2 miles each) • Construct new Ellis Avenue substation (4-breaker ring distribution station with two transformers rated 55 MVA each) • Modify existing Dean Street substation
Auburn Area Reliability Reinforcements • Re-tension (upgrade) E20 115 kV line from Auburn Street to L1 tap • Re-conductor F19 115 kV line from Bridgewater to S1 tap (4.1 miles) • Re-conductor G18 115 kV line from Bridgewater to Dupont (7.6 miles) • Replace bus work, wave trap, and change current transformer ratios at Dupont • Replace wave trap at Bridgewater • Re-tension (upgrade) C2 115 kV from Auburn Street to Dupont • Replace wave traps at both the Auburn Street and Dupont • Upgrade bus work at Dupont • Re-tension (upgrade) A94 115 kV line from Auburn Street to Parkview • Re-tension (upgrade) S1 115 kV line from Belmont Tap to Belmont • Upgrade bus work at Belmont • Re-tension E20 115 kV line from Bridgewater to L1 tap • Install new 115 kV circuit breaker between Auburn Street 345/115 kV autotransformer and the bus tie that connects the north and south 115 kV buses at

Project Description
Auburn Street
Cape Cod Supply Study • Canal to Bourne #120 115 kV line (string a second Canal – Bourne 115 kV line on the existing Canal to Bourne 115 kV double circuit structures) • Canal to Oak #399 345 kV line (convert existing #120 115 kV line to 345 kV operation) • Install 345/115 kV autotransformer at Oak Street • Add one 80 MVAR capacitor bank, STATCOM or SVC at the 115 kV Barnstable station • Expand the Canal 345 kV substation with a 3^{rd} two-breaker bay
SEMA/RI Short-term Export Enhancement • Upgrade 345 kV circuit breaker 314 Millbury substation to provide IPT capability • Upgrade 345 kV circuit breaker 142 Sherman Road substation to provide IPT capability • Replace West Walpole 104, 105, 108, 109 with IPT breakers • Re-wire West Medway 111, 112 to IPT • Potential upgrades to or replacements of breakers at o Canal o Brayton Point
SEMA/RI Long-term Export Enhancement Potential major 345 kV long-term system enhancements • Card – West Farnum – Sherman – Millbury 345 kV • Card – West Farnum – Sherman – Millbury 345 kV tapping the Millstone to Manchester 345 kV line at Card • Montville – Kent – West Farnum – Millbury 345 kV • Other major 345 kV enhancements that link SEMA/RI to the NEMA/Boston area

Project Description
Northwest Connecticut Import Capability Enhancements • Upgrade Canton-North Bloomfield terminal equipment (associated with the 1784 line) • Add 40 MVAR of capacitors at Franklin Drive • Add 50 MVAR of capacitors at Canton • Re-conductor Canton-Weingart 115 kV line 1732 (with 1272 conductor)
Norwalk-Stamford Area Glenbrook Static VAR Compensator • Add 150 MVAR statcom at the Glenbrook substation • Add three 50 MVAR 115 kV fixed capacitor banks at the Glenbrook substation • Re-terminate the 115 kV Darien-South End 1977 line at the Glenbrook substation
Southwest Connecticut Reliability Reinforcement • Build new 345 kV line from Plumtree to Norwalk • Build new 345 kV line from Devon to Trumbull Junction • Build new 345 kV line from Trumbull Junction to Norwalk • Build new 345 kV line from Devon to Beseck • Build new 345 kV line from Trumbull Junction to Pequonnock • Build new 345 kV cable from Norwalk to Glenbrook • Add new 345 kV substations at Plumtree, Norwalk, Pequonnock, Devon and Beseck Junction • Add 3-150 MVA (or larger) autotransformers at Norwalk (one), Pequonnock (one), Devon (one) and Glenbrook (one) • Add one 3-200 MVA autotransformers at Pequonnock to shift output from Bridgeport Energy to the 345 kV • Establish new 115 kV substation adjacent to Devon (East Devon) • Other 115 kV work all with new 345 kV structures • Build new 115 kV cable from Glenbrook to Norwalk Harbor • Add series reactor at Ash Creek
Norwalk Harbor to Northport 138 kV (1385) Replacement • Replace 138 kV Norwalk (CT) – Northport (NY) 1385 cable with three (3-phase) cables insulated with a solid dielectric.
East-West Oscillation Mitigation Alternatives include: • Reduce transfers from New Brunswick to New England • Control unit dispatch in Maine • Add power system stabilizers to key units in New England • Determine interdependence with other concurrent system transfers

Project Description
Connecticut Light & Power Over-dutied Circuit Breaker Replacement • Frost Bridge (one): 10K-2 • Glenbrook (four): 2T, 7T, 1753 line, 1792 line • Hanover (one): 1355 line • Manchester (three): 14T, 15T, 10K-2 • Montville (fourteen): 7T, 8T, 9T, 13T, 14T, 15T, 16T, 18T, 19T, 20T, 21T, 22T, 23T, 24T • Norwalk (seven): 1T, 2T, 3T, 4T, 6T, 7T, 9T • Bunker Hill (one): 1T • Glenbrook (three): 4T, 9T, 1887 line • Norwalk (two): 5T, 8T
Western Massachusetts Electric Over-dutied Circuit Breaker Replacement • West Springfield (six): 1544 line, 8C-1T-2, 8C-2T-2, 8C-6T-2, 8C-3T-2, 1311 line • Clinton (two): 1T, 2T • East Springfield (two): 2T, 3T
Brayton Substation Reliability Modifications • Brayton Point 345 kV and 115 kV protection upgrades; includes construction of new control house
Stamford Area Reliability Reinforcements • Re-conductor 115 kV 1880 line Rowayton Junction – Glenbrook • Re-conductor 115 kV 1890 line Ely Avenue – Glenbrook
Barbour Hill Area Reliability Reinforcement • Barber Hill re-conductoring and installation of the 3rd line into the area
Connecticut/SWCT Reliability Reinforcements • Replace the double circuit tower on the 345 kV Millstone-Southington 348 line and the 345 kV Scovill Rock-East Shore 387 line at Black Pond Junction • Southington and Frost Bridge 115 kV capacitor bank • Rebuild Glenbrook 115 kV substation • Build new 115 kV line from Frost Bridge to Walnut Hill Junction • Re-conductor 115 kV Farmington – Newington 1783 line • Re-conductor 115 kV Old Town – Norwalk 1720/1730 lines • Replace existing transformers at the Ansonia substation with load tap changing (LTC) transformers • Establish a Metro North 115/27.6 kV substation • Upgrade 1710/1730 115 kV cables • Upgrade Baird to Congress 115 kV line • New Trumbull Junction 115/13.8 kV substation • New Southport 115/13.8 kV substation • Grand Avenue – West River 115 kV cable upgrade • 69kV Falls Village area conversion to 115kV

Project Description
NSTAR Reliability Reinforcements • Mystic capacitor • Re-conductor Waltham to Sudbury 115 kV line 282-507 • Re-conductor 115 kV Auburn Street – Kingston line 191
Second New Brunwick Tie Project • Point Lepreau to Orrington – new 345 kV line
Maine CMP Reliability Reinforcements • Add 115/34.5 kV transformer at Spring Street substation • Convert Maguire Road to a switching substation by replacing switches with breakers • Add 115/34.5 kV transformer at Raymond substation on Section 208/209 • Establish a new Old Orchard Beach 115/34.5 kV substation and 115 kV line • Highland: Add 115 kV breaker • Add 115 kV line from Spring Street substation to Sewall substation • Establish a new Fore River 115/12 kV substation tapping Section 275
Rhode Island Reliability Reinforcements • Install new 345/115 kV autotransformer in SEMA/RI (e.g. Kent County, West Farnum)

Middletown Area Reliability Reinforcements
• Haddam 345/115 kV autotransformer
  • 40 MVAR capacitor banks at Haddam and Branford
  • Rebuild Manchester – Hopewell 1767 line
  • Rebuild East Meriden – North Wallingford 1466 line

Eastern Connecticut Reliability Reinforcement • Re-conductor 69 kV Montville – Gails Ferry – Tunnel line (100 – 400) • Brooklyn 345/115 kV autotransformer • Card 345kV circuit breaker • Montville 345kV circuit breaker • Re-terminate the 345-kV Millstone – Manchester 310 line at Card • Rebuild 115kV Card – Wawecus 1080 line
• **Vermont Long Range Study Projects**Chelsea 115kV Breakers - Replace two SCADA controlled motorized disconnect switches with 115kV circuit breakers at the existing Chelsea substation • Georgia Substation Ring Bus – Rebuild the existing Georgia substation 115kV bus into a ring bus • Burlington 115kV loop – 5.7 miles of new line between two existing substations • Middlesex substation relocation and breaker addition • Bennington to Manchester to Vernon Road 115kV with Manchester 115/46kv substation • Granite to Middlesex 230kV with necessary substation upgrades • Add parallel 115/69 kV transformer on Y25 at Bennington to provide backup
• **The Braintree Electric Light Department (BELD) Transmission Facilities** 18.4 Applications BELD-02-T01, BELD-02-T02, and BELD-02-X01 for the

Project Description
closing of the 115 kV Braintree loop at the Middle Street Substation #10 in Braintree, Massachusetts to improve the Braintree system reliability, with an in service date of June 2003, as detailed in Mr. H. Joseph Morley's November 22, 2002 transmittal to Mr. Richard Burke. The project consists of: • a) Closing the Braintree 115 kV loop at Middle Street Substation #10 in Braintree, Massachusetts by closing circuit breaker #102. (BELD-02-T01) • b) At the Potter Station, installation of a 115 kV, three (3) ohm series reactor inserted in the Station ring bus between Breaker #162 and Cable 115-10-16, operation of breaker #164 as normally open and to only be operated closed when the BELD 115 kV loop is open at another station, and installation of a 115 kV circuit switcher to isolate the Potter units GSU when the units are not on-line, to reduce power flows through the Braintree loop and on NSTAR line 478-509 between Grove Street Substation and Holbrook. (BELD-02-T02) • c) Installation of a second high-speed protection group, on BELD cable 115-9-4 between Grove Street and Plain Street Substations in Braintree, Massachusetts with the high-speed protection groups at both the Grove Street and Plain Street Substation being independent in accordance with NPCC criteria, to eliminate area stability concerns. (BELD-02-X01)

<u>SCHEDULE 12C</u>

<u>Determination of Localized Costs On and After January 1, 2004</u>

Introduction

The purpose of this Schedule 12C is to describe procedures that the System Operator will use in determining Localized Costs for RBUs and RTEP02 Upgrades on or after January 1, 2004.

Review and Approval

These Schedule 12C review and approval procedures are separate and distinct from any other approval procedures within the Agreement and are not a condition for receiving approval under any other section of the Agreement. If submission of a proposed plan for a Transmission Upgrade by a Participant for review pursuant to Section 18.4 of the Agreement (or the equivalent of such section as may be adopted under successor documents governing the regional transmission system in New England) is required, then the approval for Transmission Upgrade cost allocations as described under this Schedule 12C of the Tariff cannot occur sooner than after that review has been completed and it has been determined, pursuant to Section 18.4 of the Agreement (or the equivalent of such section as may be adopted under successor documents governing the regional transmission system in New England) that the Participant is free to proceed with implementation of the proposed Transmission Upgrade.

Entities conducting transmission system studies shall review and discuss transmission design and construction alternatives as they are developed under a System Impact Study ("SIS") or as part of the NEPOOL Transmission Plan with the System Operator, Reliability Committee and the Transmission Expansion Advisory Committee, as deemed appropriate by the System Operator.

1. Review Procedures For Determining Localized Costs

Every RBU and RTEP02 Upgrade shall be reviewed by the System Operator with advisory input from the Reliability Committee to determine if any of the costs associated with such upgrade are Localized Costs, except that a proposed Transmission Upgrade which costs less than $500,000 may be exempted from this review by the System Operator. The System Operator, with advisory input from the Reliability Committee, will review and update, as appropriate, the $500,000 threshold on an annual basis.

The Participant seeking cost recovery for a proposed Transmission Upgrade, including reconstruction or replacement, shall submit to the System Operator and the Reliability Committee the following information as deemed appropriate by the System Operator:

(a) A description of (i) the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered, and (ii) the most currently available study grade or better estimates of the construction, including the potential impact on the bulk power system during the construction of such upgrade, and (iii) the operating costs of the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered.

(b) A summary of the technical analysis performed for the Transmission Upgrade and the identified transmission alternatives.

(c) A review and discussion of the need for the proposed Transmission Upgrade.

(d) A discussion of why the requested Transmission Upgrade was selected over other transmission alternatives, with a description of the benefits of the proposed Transmission Upgrade over other transmission alternatives from an operational, timing of implementation, cost and reliability perspective.

If in reviewing the application and associated information, the System Operator, with advisory input from the Reliability Committee, decides that additional information, review, or study is required prior to acting on the application, the System Operator, with advisory input from the Reliability Committee, may elect to defer action and solicit supplementary information, review, or study as required. Sources for such additional information may be, but are not limited to, the entity sponsoring the application, Transmission Owners, and the Reliability Committee.

The System Operator shall determine what those reasonable requirements are that are 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 System Operator will consider, in accordance with Schedule 12C of this Tariff, the reasonableness of the proposed design and construction method with respect to (i) Good Utility Practice, (ii) the current engineering design and construction practices in the area in which the Transmission Upgrade is built, (iii) alternate feasible and practical Transmission Upgrades and (iv) the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrades. The costs of Transmission Upgrades that exceed those reasonable requirements, as determined above, shall be deemed Localized Costs. Local siting requirements for transmission facilities shall not be dispositive of whether or not Localized Costs exist with respect to any particular Transmission Upgrade.

The System Operator is authorized to develop detailed procedures to fulfill the objectives and requirements of this Schedule 12C.

2. Additional Transmission Upgrade Costs or Design Changes Subsequent to the System Operator's Determination of Localized Costs

If the costs associated with a Transmission Upgrade exceed the estimated Pool-Supported PTF costs determined in the original Localized Costs review by ten percent, or the design associated with the construction of a Transmission Upgrade is materially changed subsequent to the System Operator's determination of Localized Costs, then the applicant for Pool-Supported PTF costs shall be required to submit its Transmission

Upgrade again to a review by the System Operator to determine if any of the incremental costs or costs associated with the change in design are Localized Costs.

3. Dispute Resolution Regarding Determination of Localized Costs

The System Operator's determination of Localized Costs under the Tariff shall take effect on the date on which the System Operator issues its written findings and determination. The applicant for cost recovery (the "Applicant") whose project is deemed to include Localized Costs may dispute such decision by the System Operator by submitting within 60 days of such decision formal written notice of the dispute to the System Operator, describing in detail the basis for its challenge of the System Operator's determination. The Applicant and the System Operator shall then enter into good faith negotiations for a period not to exceed 60 days from the date of the Applicant's written notice to try to resolve the dispute.

If there is no satisfactory resolution of the dispute at the end of the negotiation period, the Applicant shall then have the right to file a Section 206 complaint with the Commission.

ATTACHMENT 2

4. Rights of way and land owned by Participants required for the installation of facilities which constitute PTF under (1), (2) or (3) above.

The Reliability Committee shall review at least annually the status of transmission lines and related facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalogue of PTF facilities.

The following examples indicate the intent of the above definitions:

(i) Radial tap lines to local load are excluded.

(ii) Lines which loop, from two geographically separate points on the PTF, the supply to a load bus from the PTF are included.

(iii) Lines which loop, from two geographically separate points on the PTF, the connections between a generator bus and the PTF are included.

(iv) Radial connections or connections from a generating station to a single substation or switching station on the PTF are excluded, unless the requirements of paragraph (3) above are met.

Transmission facilities owned by a Related Person of a Participant which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England transmission network shall also constitute PTF provided (i) such Related Person files with the Secretary of the Participants Committee its consent to such treatment; and (ii) the Participants Committee determines that treatment of the facility as PTF will facilitate accomplishment of NEPOOL's objectives. If a facility constitutes PTF pursuant to this paragraph, it shall be treated as "owned" by a Participant for purposes of the Tariff and the other provisions of Part Four of the Agreement.

15.1A Of those transmission facilities that are upgrades, modifications or additions to the NEPOOL Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section 15.1 or Section 15.1A of this Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the criteria specified in Section 15.1 or Section 15.1A of this Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England), shall remain classified as PTF for all purposes under this Agreement and the Tariff.

15.2 Maintenance and Operation in Accordance with Good Utility Practice. Each Participant which owns or operates PTF or other transmission facilities rated 69 kV or above shall, to the fullest extent practicable, cause all such transmission facilities owned or operated by it to be designed, constructed, maintained and operated in accordance with Good Utility Practice.

15.3 Central Dispatch. Each Participant which owns or operates PTF or other transmission facilities rated 69 kV or above shall, to the fullest extent practicable, subject all such transmission facilities owned or operated by it to central dispatch by the System Operator; provided, however, that each Participant shall at all times be the sole judge as to whether or not and to what extent safety requires that at any time any of such facilities will be operated at less than their full capability or not at all.

15.4 Maintenance and Repair. Each Participant shall, to the fullest extent practicable: (a) cause transmission facilities owned or operated by it to be withdrawn from operation for maintenance and repair only in accordance with maintenance schedules reported to and published by the System Operator in accordance with procedures approved or established by the Tariff Committee from time to time, (b) restore such facilities to good operating condition with reasonable promptness, and (c) in emergency situations, accelerate maintenance and repair at the reasonable request of the System Operator in accordance with rules approved by the Tariff Committee.

ATTACHMENT 3

Sheet No.

Sheet No.

Sheet No.

Sheet No.

Sheet No.

Sheet No.

1.21 **Economic Upgrade:** Those additions and upgrades that are not related to the interconnection of a generator, and, in the System Operator'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 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.

1.22 **Elective Transmission Upgrade:** is a Transmission Upgrade that is participant funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Economic Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the System Operator in accordance with Section 50.2 on a date after the addition or modification already has been otherwise identified in the current NEPOOL Transmission Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

1.31 **Firm Transmission Service:** Service for Native Load Customers, firm Regional Network Service (Network Integration Transmission Service), service for Excepted Transactions and certain other transactions listed in Attachment G-3, Firm Internal Point-To-Point Transmission Service, or Firm MTF Service.

1.32 **FTR Auction:** The periodic auction of FTRs conducted by the ISO in accordance with Section 7 of Market Rule 1.

1.32A **Generator Interconnection Related Upgrade**: An addition to or modification of the NEPOOL Transmission System pursuant to Section 50.1 to effect the interconnection of a new generating unit or an existing generating unit whose capacity is being materially changed and increased, whether or not the interconnection is being effected to meet the Minimum Interconnection Standard. As to Category A Projects (as defined in Schedule 11), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Minimum Interconnection Standard for which the Generator Owner has committed to pay prior to October 29, 1998.

1.33 **Generator Owner:** The owner, in whole or part, of a generating unit whether located within or outside the NEPOOL Control Area.

1.34 **Good Utility Practice:** Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region.

1.42A **Local Benefit Upgrade(s) ("LBUs"):** a 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 Section 15.1 of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England).

1.43 **Local Network:** The transmission facilities constituting a local network identified on Attachment E, and any other local network or change in the designation of a Local Network as a Local Network which the Participants Committee may designate or approve from time to time. The Participants Committee may not unreasonably withhold approval of a request by a Participant that it effect such a change or designation.

1.44 **Local Network Service:** Local Network Service is the service provided, under a separate tariff or contract, by a Participant that is a Transmission Provider to another Participant or other entity connected to the Transmission Provider's Local Network to permit the other Participant or entity to efficiently and economically utilize its resources to serve its load.

1.45 **Local Point-To-Point Service:** Local Point-To-Point service is Point-To-Point Transmission Service provided, under a separate tariff or contract, by a

Participant that is a Transmission Provider over Non-PTF or distribution facilities to permit deliveries to or from an interconnection point on the PTF.

1.45A Localized Costs: the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the System Operator 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 System Operator will consider, in accordance with Schedule 12C of this Tariff, 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, efficiency and reliability of the proposed Transmission Upgrade. Prior to any recovery of costs under this Tariff associated with a RTEP02 Upgrade or a Regional Benefit Upgrade, the System Operator, 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 System Operator shall identify them in the NEPOOL Transmission Plan.

1.46 Locational Marginal Price (LMP): Is as defined and calculated pursuant to Market Rule 1.

1.56 **Native Load Customers:** The wholesale and retail power customers of a Participant or other entity which is a Transmission Provider on whose behalf the Participant or other entity, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

1.57 **NEMA or "Northeast Massachusetts" Upgrade:** Is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that is not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section 18.4 of the Restated NEPOOL Agreement; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of this Tariff.

1.58 **NEPOOL:** The New England Power Pool, the power pool created under and governed by the Agreement, and the entities collectively participating in the New England Power Pool.

1.59 **NEPOOL Control Area:** The Control Area (as defined in Section 1.11) for NEPOOL.

of the unit shall be limited in accordance with Section 49, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the NEPOOL Control Area for so long as any Participant has an Ownership Share in the resource or resources which is being delivered to it in the NEPOOL Control Area to serve Network Load located in the NEPOOL Control Area or other designated Network Loads contemplated by Section 43.3 of this Tariff taking Regional Network Service. (2) With respect to Non-Participant Network Customers, any generating resource owned, purchased or leased by the Network Customer which it designates to serve Network Load.

1.71 [Deleted.]

1.72 Node: Is as defined pursuant to Market Rule 1.

1.73 Non-Firm Point-To-Point Transmission Service: Point-To-Point Transmission Service under this Tariff that is subject to Curtailment or Interruption under the circumstances specified in Section 28.7 of this Tariff.

1.74 Non-Participant: Any entity that is not a Participant.

1.97 Pre-1997 PTF Rate: The transmission rate of a Participant determined in accordance with paragraph (5) of Schedule 9 to this Tariff.

1.98 Qualified Upgrade Award: Is as defined and determined pursuant to Market Rule 1.

1.99 Reactive Supply and Voltage Control From Generation Sources Service: This service is the form of Ancillary Service described in Schedule 2.

1.100 Real-Time Energy Market: Is as defined and determined pursuant to Market Rule 1.

1.101 Receiving Party: The entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under this Tariff.

1.101A Regional Benefit Upgrade(s) ("RBU(s)"): a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in Section 15.1 of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England); and (iii) is included in the NEPOOL Transmission Plan as either a Reliability Upgrade or an Economic Upgrade identified as needed pursuant to Section 51 of this Tariff. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of this Tariff (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115 kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in Section 15.1 or Section 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England).

1.102 **Regional Network Service:** The transmission service over the PTF described in Part II and Part VI of this Tariff.

1.103 **Regulation and Frequency Response Service:** This service is the form of Ancillary Service described in Schedule 3.

amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Upgrades.

1.107 **Reserved Capacity:** The maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the PTF or MTF between the Point(s) of Receipt and the Point(s) of Delivery under Part V or Schedule 18 of this Tariff. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis.

1.108 **Resource:** Is as defined pursuant to Market Rule 1.

1.108A **RTEP02 Upgrade(s):** a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by the System Operator's Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by the System Operator. The RTEP02 Upgrades are listed in Schedule 12B of this Tariff.

1.109 **Scheduling, System Control and Dispatch Service:** This service is the form of Ancillary Service described in Schedule 1.

1.110 Second Effective Date: The date on which the provisions of Part Three of the Agreement (other than the Installed Capability Responsibility provisions of Section 12) shall become effective and shall be such date as the Commission may fix on its own or pursuant to a request of the Participants Committee.

1.111 Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the System Operator for service under this Tariff.

1.112 Service Commencement Date: The date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with Section 29.3 or Section 41.1 under this Tariff, or in the case of Regional Network Service which is not required to be furnished under a Service Agreement pursuant to Section 48 of this Tariff, the date service actually commences.

1.113 SMD Effective Date: Is as defined and determined pursuant to Market Rule 1.

1.114 System Impact Study: An assessment pursuant to Part V, VI or VII of this Tariff of (i) the adequacy of the NEPOOL Transmission System to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or Internal Point-To-Point Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

to the reciprocity requirements specified in the Tariff, or an individual such Participant, whichever is appropriate.

1.124A **Transmission Upgrade(s):** an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of this Tariff governing rates and service on the PTF on or after January 1, 2004. The categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of this Tariff.

1.125 **Use:** For a Transmission Customer which has exercised its option to take Internal Point-To-Point Service to serve all or a portion of its load at any Point of Delivery, the greatest for the hour of (i) the maximum amount that it will receive in the hour, as determined from meters and adjusted for losses, at that Point of Delivery from the resources covered by its Completed Applications and from Interchange Transactions, or (ii) the portion of its Installed Capability Responsibility (as determined in accordance with the Agreement) for the month which must be satisfied at that Point of Delivery with such resources if the Transmission Customer is a Participant, or (iii) the portion of its Operable Capability Responsibility (as determined in accordance with the Agreement) for the hour which must be satisfied at that Point of Delivery with such resources if the Transmission Customer is a Participant, or (iv) the amount of capacity from such resources that the Transmission Customer must receive, adjusted to include losses, at such Point of Delivery for the hour to meet its reliability obligations if the Transmission Customer is a Non-Participant. Use shall be expressed in terms of whole Kilowatts on a sixty-minute interval (commencing on the clock hour) basis.

4.9 Special Constraint Resource Service: The rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 19 of this Tariff and Market Rule 1.

5 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding the NEPOOL Open Access Same-Time Information System and standards of conduct are set forth in 18 C.F.R. §37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities). In the event available transmission capability, as posted on OASIS, is insufficient to accommodate a request for Firm Internal Point-To-Point Service, for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or an Elective Transmission Upgrade, additional studies may be required as provided by this Tariff pursuant to Sections 33, 44 and 50.

6 Local Furnishing and Other Tax-Exempt Bonds

6.1 Participants That Own Facilities Financed by Local Furnishing or Other Tax-Exempt Bonds: This provision is applicable only to Participants that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local

33.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study agreement shall clearly specify the System Operator's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the System Operator and any affected Participants will rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer shall not be assessed a charge for such existing studies; however, the Eligible Customer shall be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the PTF and indirectly affected MTF of the customer request for Internal Point-To-Point Service or for an Elective Transmission Upgrade.

(ii) If in response to multiple Eligible Customers requesting a similar study in relation to the same competitive solicitation, a single System Impact Study is sufficient for the System Operator to accommodate the requests, the costs of that study will be equitably prorated among the Eligible Customers.

completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required upgrades, modifications or additions to the PTF, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the affected Transmission Provider(s) or other entities that will be responsible for the construction of the new facilities or upgrades equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

In addition to the foregoing, each Facilities Study performed on or after the SMD Effective Date shall, if requested by the Transmission Customer, contain a non-binding estimate from the System Operator of the Qualified Upgrade Awards, if any, resulting from the construction of the new facilities. After completion of the

46 Rates and Charges

The Network Customer shall pay Transmission Providers for any Direct Assignment Facilities and its share of the cost of any required upgrades, modifications or additions to the PTF and applicable study costs consistent with Commission policy and Schedules 11 and 12, along with the payment to the System Operator of the charges for Ancillary Services and the charge for Regional Network Service provided under this Tariff.

46.1 Determination of Network Customer's Monthly Network Load: The Network Customer's "Monthly Network Load" is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 43.3) coincident with the coincident aggregate load of the Participants and other Network Customers served in each Local Network in the hour in which the coincident load is at its maximum for the month ("Monthly Peak").

47 Operating Arrangements

47.1 Operation under The Network Operating Agreement: The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement including the information identified in subsection (g) below, or for any removal of Upgrades from the Plan pursuant to subsection (c) below.

(c) An Upgrade may be approved for addition to the NEPOOL Transmission Plan by the System Operator at any time in a given year and in doing so the System Operator may consult with and consider input from the Transmission Expansion Advisory Committee, within the scope of its respective functions as specified in subsection (b) of Section 51.2, and the Reliability Committee within the scope of its function as specified in Section 8.4(a) of the Agreement. Similarly, an Upgrade may be approved for removal from the NEPOOL Transmission Plan by the System Operator at any time in a given year if the market responds by proposing alternative generation projects, Merchant Transmission Facilities in accordance with Section 51.8, or demand-side projects, or other circumstances arise such that the need for the Upgrade no longer exists, and in doing so the System Operator may consult with and consider input from the Transmission Expansion Advisory Committee, within the scope of its functions as specified in subsection (b) of Section 51.2, and the Reliability Committee within the scope of its function as specified in Section 8.4(a) of the Agreement; provided that the entity responsible for the construction of the Upgrade is reimbursed for any costs prudently incurred or prudently committed to be incurred in connection with the planning, preparation for construction, and/or construction of the Upgrades removed from the Plan. All Upgrades approved for addition or removal in such interim Plans during this planning process must meet the requirements of subsection (a) of Section 51.3. In the event that the estimated cost of a proposed Upgrade exceeds $20 million (which threshold amount shall be reviewed annually by the System Operator and reset as it reasonably deems appropriate), a member of a subcommittee of the System Operator's Board will attend such meeting at which the ISO will seek the Reliability Committee's advice on the inclusion of the proposed Upgrade into the NEPOOL Transmission Plan. An approval of the interim Plan by the System Operator made pursuant to this subsection (c) shall have the same effect with regard to cost reimbursement and with regard to inclusion or removal of an Upgrade from the Plan as an approval of the Plan made by the System Operator's Board of Directors pursuant to Section 51.4(i) of this Tariff.

(d) The Transmission Owners, those entities requesting transmission service or interconnection, and any other entities proposing to provide facilities to be integrated into the NEPOOL Control Area or alternatives to such facilities shall supply upon request and subject to applicable confidentiality requirements of the NEPOOL Information Policy any information and data reasonably required to prepare a NEPOOL Transmission Plan or to perform a transmission enhancement and expansion study. Any confidential cost estimate for a proposed Upgrade to the PTF that is or may be subject to subsection (a) of Section 51.6 shall be considered by the System Operator to be competitively sensitive, confidential information and shall be considered the estimator's confidential information under the NEPOOL Information Policy, and shall not be disclosed by the System Operator to other entities that may be eligible to submit a proposal in accordance with Section 51.6, including, without limitation, other Transmission Owners. Any other information or data provided shall be subject to the rights and obligations of the NEPOOL Information Policy.

(e) The NEPOOL Transmission Plan shall be developed in coordination with the transmission systems of the surrounding Control Areas and the regional reliability councils, as appropriate.

(f) At the initiation of an effort to update a Plan or develop a new Plan, the System Operator may solicit input for the updated or new Plan from members of the Transmission Expansion Advisory Committee and the Reliability Committee. The Transmission Expansion Advisory Committee shall meet to perform its respective functions in connection with the preparation of the NEPOOL Transmission Plan, as specified in subsection (b) of Section 51.2. Thereafter, drafts of the NEPOOL Transmission Plan shall be provided to the Transmission Expansion Advisory Committee and the Reliability Committee and input from those committees shall be received and considered by the System Operator in preparing and revising subsequent plan approvals. Before an interim NEPOOL Transmission Plan is presented to the System Operator's Board of Directors for approval, a subcommittee of that Board shall hold a public meeting to receive input directly and to discuss any proposed revisions to the NEPOOL Transmission Plan.

(g) For potential Upgrades proposed to be included in the NEPOOL Transmission Plan, the System Operator (in connection with the preparation of the NEPOOL Transmission Plan) shall identify, to the extent practicable, the anticipated benefits of the proposed Upgrade. To the extent an Upgrade is proposed to reduce bulk power system costs to load system-wide, the System Operator shall publish data and information, in a manner that does not violate the Information Policy, that would reasonably permit entities to calculate the costs and economic benefits of such an Upgrade and, to the extent feasible, the distribution of such benefits within the region. Such information shall be published so as to permit analysis for a reasonably limited period of time (generally ten years or less), and shall include the effects of (i) all projects for which applications have been received for approval under Section 18.4 of the Restated NEPOOL Agreement, including but not limited to proposed generation projects and Merchant Transmission Facilities and (ii) demand-side projects planned within the NEPOOL Control Area and identified to the System Operator.

(h) Any entity with a representative on the Transmission Expansion Advisory Committee may request that specific proposals for alternative solutions or facilities, including but not limited to generation projects, transmission projects, and/or demand-side projects, be accounted for in the development of the NEPOOL Transmission Plan. The NEPOOL Transmission Plan shall account for such proposals where appropriate provided that the NEPOOL Transmission Plan shall not include in the list of Upgrades any proposed resource participating in competitive electricity markets or Merchant Transmission Facilities. If a proposal is not accounted for in the interim Plan to be recommended to the System Operator's Board of Directors, the recommendation to the Board shall include a written explanation of why such proposal(s) were not accounted for in the interim Plan, which shall be made public.

(i) The interim NEPOOL Transmission Plan shall be presented at least annually to the System Operator's Board of Directors for approval. At least every three years, a Plan shall reflect the results of a new comprehensive transmission planning and expansion study conducted pursuant to Section 51.5. The interim Plan shall be presented to the System Operator's Board of Directors no later than September 30 of each year and shall be acted on by the Board within 60 days of receipt. The Board of Directors may approve the interim Plan as submitted, modify the interim Plan or remand all or any portion of it back with guidance for development of a revised interim Plan in accordance with this Section 51.4. The Board of Directors may consider the Plan in executive session, and shall consider in its deliberations the views of the subcommittee of the

SCHEDULE 12

Reliability Upgrade, Economic Upgrade and Elective Transmission Upgrade Costs

Note: This Schedule 12 shall remain in effect through and including December 31, 2003, to be superseded as hereinafter provided.

(1) Allocation and Recovery of Costs for Reliability Upgrades and Economic Upgrades Associated with the NEPOOL Transmission Plan. All costs of MTF shall be recovered in accordance with the recovery mechanism for those facilities that is filed with and accepted by the Commission. All costs associated with Upgrades for the interconnection of Merchant Transmission Facilities shall be treated in the same fashion and subject to the same rights and obligations as Generator Interconnection Related Upgrade Costs for Category C Projects under Schedule 11 of this Tariff, including the provisions of Sections (5), (6) and (7) of that Schedule, but excluding the provisional clause at the end of the first sentence in Section (5) of Schedule 11. To the extent not otherwise covered above or by Part III or Schedule 11 of the Tariff or Sections (2) or (3) of this Schedule 12 below, the costs of a Reliability Upgrade and Economic Upgrade shall be allocated as follows:

(a) If entities have agreed to bear some or all of the cost responsibility for an Upgrade, the Upgrade costs shall be allocated to such entities in accordance with that agreement.

SCHEDULE 12

Transmission Cost Allocation
On and After January 1, 2004

On January 1, 2004, this Schedule 12 shall supersede in its entirety the version of Schedule 12 that is in effect as of June 25, 2003 ("Current Schedule 12"). Current Schedule 12 shall remain in effect through and including December 31, 2003. This Schedule 12 describes the cost allocation treatment of upgrades, modifications or additions to the transmission system in New England on and after January 1, 2004. Nothing in this Schedule 12 shall eliminate the PTF status of transmission facilities that were PTF on December 31, 2003; and any upgrades to such facilities that continue to meet the definition of PTF specified in Section 15.1 or Section 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) shall be classified as PTF for all purposes under the Agreement and this Tariff.

A. Process for Categorizing Upgrades for Cost Allocation:

Upgrades, modifications or additions to the NEPOOL Transmission System shall be categorized by the System Operator, with advisory input from the Reliability Committee and the Transmission Expansion Advisory Committee, as appropriate. A list of categorized Transmission Upgrades shall be made part of each annual and interim NEPOOL Transmission Plan, subject to the provisions of Section 51 of this Tariff.

B. Transmission Cost Allocation By Category:

1. Generator Interconnection Related Upgrades:

The cost for all Generator Interconnection Related Upgrades shall be allocated pursuant to Schedule 11 of this Tariff.

2. Elective Transmission Upgrades:

The cost for all Elective Transmission Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this Tariff, but shall be allocated solely to the entity or entities volunteering to make and pay for such Elective Transmission Upgrades.

3. NEMA Upgrades:

The cost for all NEMA Upgrades shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades continue to meet the definition of PTF under either Section 15.1 or 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) and allocated to Transmission Customers taking service under this Tariff.

4. RTEP02 Upgrades:

The costs for all RTEP02 Upgrades placed in service on or before December 20, 2007, shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades continue to meet the definition of PTF under either Section 15.1 or 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) and allocated to Transmission Customers taking service under this Tariff.

5. Regional Benefit Upgrades:

The cost for all Regional Benefit Upgrades, as well as all transmission facilities that were PTF as of December 31, 2003 and upgrades to such facilities that meet the definition of PTF under either Section 15.1 or 15.1A (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England), shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades and such existing PTF continue to meet the definition of PTF under either Section 15.1 or 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) and allocated to Transmission Customers taking service under this Tariff. Economic Upgrades that are not RBUs shall not be included in the Pool-Supported PTF Costs recoverable under this Tariff.

6. Local Benefit Upgrades:

The cost for Local Benefit Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this Tariff.

7. Localized Costs:

Localized Costs shall not be included in the Pool-Supported PTF costs recoverable under this Tariff, but instead the responsibility for Localized Costs related to any RTEP02 Upgrades and any Regional Benefit Upgrades shall be the responsibility of the entity or entities causing or subject to such Localized Costs. The System Operator, in accordance with Schedule 12C of this Tariff, shall review RTEP02 Upgrades and Regional Benefit Upgrades and identify any Localized Costs associated with them.

C. Merchant Transmission Facilities Cost Allocation

The cost of all Merchant Transmission Facilities, including the cost of Transmission Upgrades required to interconnect the Merchant Transmission Facilities to the PTF, shall be the responsibility of the developer of the Merchant Transmission Facilities, and shall not be included in the Pool-Supported PTF costs recoverable under this Tariff.

SCHEDULE 12A

NEMA Upgrades

A "Northeast Massachusetts Upgrade" is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section 18.4 of the Restated NEPOOL Agreement; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. The aggregate capital costs of the Northeast Massachusetts Upgrades which qualify as Pool-Supported PTF costs shall not exceed $35,000,000. A general description of the projects which constitute the NEMA Upgrades is provided in the list below.

1. Framingham 230/115kV autotransformer and breaker replacement
2. Upgrade Framingham to West Medway 230 kV line (240-601)
3. Add Mystic 345kV breaker #101S
4. West Walpole 345/115kV autotransformer and breaker replacement
5. Rebuild Speen Street to Sudbury 115kV line (342-507) and replace breakers at both ends
6. Waltham 230/115kV autotransformer and breaker replacement
7. Upgrade Waltham to West Medway 230 kV line (282-602)
8. Upgrade Framingham to Speen Street 115kV line (433-507) and replace breakers at Framingham
9. Add a third Waltham 115kV phase shifting transformer
10. Upgrade Sherborn 115kV station equipment
11. Merrimack (New Hampshire) 230/115kV autotransformer replacement

SCHEDULE 12B

RTEP02 Upgrades

Following is a general description of projects which constitute the RTEP02 Upgrades.

Project Description
New Brunswick – New England Tie Performance Enhancement • Series compensation
MEPCO Special Protection Systems Alternative • Alternative 1: Decommission existing SPS and install new direct logic sensing Transfer Trip SPS. • Alternative 2: Extend time delay on existing flow based SPS and install new direct logic sensing Transfer Trip SPS. • Alternative 3: Decommission existing SPS and install new direct logic sensing Transfer Trip SPS with fault discrimination.
Bangor Hydro Electric Down East Transmission Reliability Improvement • New transmission path between Rebel Hill and the Epping/Washington County area • Reconfiguration of existing facilities.
CMP Autotransformer-Outage Reliability Improvement • Review/mitigation of 120°F sag limits. • Mitigation of line overloading that limits select pockets of generation. • Mitigation of low voltages that may be improved with implementation of the new Maine Voltage Operating Guide and capacitor bank additions.
Maine and New Hampshire Voltage Enhancements • Install 24 MVAR capacitors at Sanford 115 kV substation • Add 50 MVARs of capacitors at Ocean Road and Madbury • Add 60 MVARs of capacitors at Three Rivers • Add 170 MVARs of capacitors at Maxcys and western Maine
Maine – New Hampshire Transfer Capability Short Term Enhancements • Schiller to Bolt Hill 115 kV N133 line upgrade • Quaker Hill to Three Rivers 115 kV 197 line upgrade • Maguire to Three Rivers 115 kV 250 line upgrade • Alternate project: Southern Maine substation re-configuration or series reactor

Project Description
Requirements for Closing PSNH's Y138 Line – Saco Valley to White Lake • Saco Valley 115 kV breaker additions • 120 MVAR of shunt reactive compensation is needed between the Maine and New Hampshire ends of the transmission system • Series reactor overload mitigation system is needed on the New Hampshire end of the Beebe to White Lake 115 kV B112 line • Alternative: Beebe 115kV phase shifter • Beebe substation terminal equipment upgrades on B112 line to change out circuit breaker, disconnect switches, bus work and secondary equipment • Re-rate 28 miles of 115 kV Section 214 transmission line from Kimball Road to Harrison and Lovell in Maine • White Lake 115kV capacitor

Southern New Hampshire Reinforcements
• Rebuild Scobie 115 kV substation to breaker and a half arrangement
• Re-conductor Deerfield to Garvins 115 kV G146 line
• Add a second 345/115 kV 400 MVA autotransformer at Scobie substation
• Add a second 345/115 kV 400 MVA autotransformer at Deerfield substation
• Add three 50 MVAR capacitor banks at the Deerfield 115 kV substation
• Deerfield dynamic voltage control
• New 115 kV line from Reeds Ferry – Huse Road
• Upgrade Greggs 115 kV substation
• Upgrade Merrimack 115 kV substation
• Add Amherst 345 kV 4 – breaker ring bus
• Add six 50 MVAR capacitor banks at the Scobie 115 kV substation
• Re-terminate Deerfield autotransformer and/or second breaker
• Re-conductor two 115 kV circuits from Schiller – Scobie (U181/H141 and E194/R193)
• Alternatives considered:
    o Newington 345/115 kV autotransformer
    o Coburn Road 345/115 kV autotransformer
    o Rebuilding the 115 kV Deerfield – Laconia D140 line

Northwest Vermont Near-term Voltage Reinforcement • Essex Capacitors, two 24.75 MVAR 115 kV banks
Rutland Reliability Project • Energize existing Coolidge-West Rutland line at 345 kV • Add two West Rutland 345/115 kV transformers • Add three 345 kV circuit breakers at Coolidge • Add three 115 kV circuit breakers at West Rutland • Add two 24.75 MVAR 115 kV capacitor banks at Coolidge

Project Description
Northwest Vermont Reliability Project • New Haven-West Rutland 345 kV line and 345/115 kV New Haven substation with 115 kV ring bus • Granite 230 kV PAR, 25 MVAR capacitor bank and breaker additions • 150 MVAR STATCOM at Granite • Blissville 115 kV PAR • New Haven-Vergennes-Queen City 115 kV line • Hartford 115 kV breaker – Add an existing 115 kV motorized SCADA controlled disconnect switch with a circuit breaker at Hartford substation on the line toward the Chelsea substation • Granite to Middlesex 230 kV • Addition of 230/115 kV and 345/115 kV autotransformers • Addition of breakers and shunt devices
Vermont Northern Loop Project • New Irasburg – Newport 115 kV line (“northern loop”) operated synchronous with VELCO (7 miles of new 115/46kV double circuit construction) • New 115 kV breaker at St. Johnsbury • Two new 115 kV breakers at Irasburg • New five breaker 115 kV ring bus at Highgate • St Albans Line reconfiguration and substation upgrade-Reconfigure St Albans lines and breakers to replace the single 115kV tap line with two “in and out” lines

Monadnock Regional Reinforcement
• Addition of switched capacitor banks at Chestnut Hill 115 kV bus
• Potential alternatives:
    o New Fitzwilliam 345/115 kV substation north of Flagg Pond tapped onto the Scobie Pond – Vermont Yankee 345 kV 379 line and separation of the existing lines between Flagg Pond and Pratts Junction.
    o (Third) Pratts Junction to Flagg Pond 115 kV line

Greater Metro-West Transmission Supply Study • Install tie breaker and second radial Northborough – Hudson 115 kV line • Re-conductor Woodside-Northborough / Fitch Rd 69 kV W-23 line • Millbury 115 kV 63 MVAR Capacitor Bank • Northborough 115 kV 54 MVAR Capacitor Bank • Fitch Road – Rebuild 69 kV station • Re-conductor Fitch Rd to Pratts Junction 69 kV N40 line • Install Woodside 69 kV breaker

Project Description
Central Massachusetts Reliability Reinforcement • Re-conductor V174 Carpenter Hill to Millbury 115 kV • Install new 345/115 kV autotransformer in Central Massachusetts (e.g. Pratts Junction, Millbury) • Install second Wachusett 115/69 kV autotransformer • Pratts Junction 115/69/13.8 kV transformer replacement
Springfield/Western Massachusetts Reliability Reinforcements • Improve sag clearances on the 115 kV Blandford – Pleasant 1421 line • Pleasant 115 kV capacitor bank • As determined by study
NEMA/Boston Short-term Reliability Reinforcements Potential North Shore upgrades include: • B154N/C155N Ward Hill to Salem Harbor 115 kV line upgrades (re-sag/re-conductor) • Second Ward Hill 345/115 kV transformer • Completion of the Golden Hills 345 kV ring bus • Split up switching of Mystic-Golden Hills 345 kV cables (348X+Y) • F-158N and Q-169 Golden Hills to Everett and to Lynn 115 kV line upgrades • Other 115 kV line upgrades
NEMA/Boston Long-term Reliability Reinforcements Potential upgrades include: • Mystic-K Street-Kingston 345 kV loop • Other 345 kV and/or 115 kV line upgrades • Build 345 kV line from Scobie to Tewksbury
Norwood Municipal Light Department Reliability Reinforcements • Install two new 115 kV underground lines to Norwood's new Ellis Avenue substation (2.2 miles each) • Construct new Ellis Avenue substation (4-breaker ring distribution station with two transformers rated 55 MVA each) • Modify existing Dean Street substation

Project Description
Auburn Area Reliability Reinforcements • Re-tension (upgrade) E20 115 kV line from Auburn Street to L1 tap • Re-conductor F19 115 kV line from Bridgewater to S1 tap (4.1 miles) • Re-conductor G18 115 kV line from Bridgewater to Dupont (7.6 miles) • Replace bus work, wave trap, and change current transformer ratios at Dupont • Replace wave trap at Bridgewater • Re-tension (upgrade) C2 115 kV from Auburn Street to Dupont • Replace wave traps at both the Auburn Street and Dupont • Upgrade bus work at Dupont • Re-tension (upgrade) A94 115 kV line from Auburn Street to Parkview • Re-tension (upgrade) S1 115 kV line from Belmont Tap to Belmont • Upgrade bus work at Belmont • Re-tension E20 115 kV line from Bridgewater to L1 tap • Install new 115 kV circuit breaker between Auburn Street 345/115 kV autotransformer and the bus tie that connects the north and south 115 kV buses at Auburn Street
Cape Cod Supply Study • Canal to Bourne #120 115 kV line (string a second Canal – Bourne 115 kV line on the existing Canal to Bourne 115 kV double circuit structures) • Canal to Oak #399 345 kV line (convert existing #120 115 kV line to 345 kV operation) • Install 345/115 kV autotransformer at Oak Street • Add one 80 MVAR capacitor bank, STATCOM or SVC at the 115 kV Barnstable station • Expand the Canal 345 kV substation with a 3rd two-breaker bay
SEMA/RI Short-term Export Enhancement • Upgrade 345 kV circuit breaker 314 Millbury substation to provide IPT capability • Upgrade 345 kV circuit breaker 142 Sherman Road substation to provide IPT capability • Replace West Walpole 104, 105, 108, 109 with IPT breakers • Re-wire West Medway 111, 112 to IPT • Potential upgrades to or replacements of breakers at o Canal o Brayton Point

Project Description
SEMA/RI Long-term Export Enhancement Potential major 345 kV long-term system enhancements • Card – West Farnum – Sherman – Millbury 345 kV • Card – West Farnum – Sherman – Millbury 345 kV tapping the Millstone to Manchester 345 kV line at Card • Montville – Kent – West Farnum – Millbury 345 kV • Other major 345 kV enhancements that link SEMA/RI to the NEMA/Boston area
Northwest Connecticut Import Capability Enhancements • Upgrade Canton-North Bloomfield terminal equipment (associated with the 1784 line) • Add 40 MVAR of capacitors at Franklin Drive • Add 50 MVAR of capacitors at Canton • Re-conductor Canton-Weingart 115 kV line 1732 (with 1272 conductor)
Norwalk-Stamford Area Glenbrook Static VAR Compensator • Add 150 MVAR statcom at the Glenbrook substation • Add three 50 MVAR 115 kV fixed capacitor banks at the Glenbrook substation • Re-terminate the 115 kV Darien-South End 1977 line at the Glenbrook substation
Southwest Connecticut Reliability Reinforcement • Build new 345 kV line from Plumtree to Norwalk • Build new 345 kV line from Devon to Trumbull Junction • Build new 345 kV line from Trumbull Junction to Norwalk • Build new 345 kV line from Devon to Beseck • Build new 345 kV line from Trumbull Junction to Pequonnock • Build new 345 kV cable from Norwalk to Glenbrook • Add new 345 kV substations at Plumtree, Norwalk, Pequonnock, Devon and Beseck Junction • Add 3-150 MVA (or larger) autotransformers at Norwalk (one), Pequonnock (one), Devon (one) and Glenbrook (one) • Add one 3-200 MVA autotransformers at Pequonnock to shift output from Bridgeport Energy to the 345 kV • Establish new 115 kV substation adjacent to Devon (East Devon) • Other 115 kV work all with new 345 kV structures • Build new 115 kV cable from Glenbrook to Norwalk Harbor • Add series reactor at Ash Creek
Norwalk Harbor to Northport 138 kV (1385) Replacement • Replace 138 kV Norwalk (CT) – Northport (NY) 1385 cable with three (3-phase) cables insulated with a solid dielectric.

Project Description
East-West Oscillation Mitigation Alternatives include: • Reduce transfers from New Brunswick to New England • Control unit dispatch in Maine • Add power system stabilizers to key units in New England • Determine interdependence with other concurrent system transfers
Connecticut Light & Power Over-dutied Circuit Breaker Replacement • Frost Bridge (one): 10K-2 • Glenbrook (four): 2T, 7T, 1753 line, 1792 line • Hanover (one): 1355 line • Manchester (three): 14T, 15T, 10K-2 • Montville (fourteen): 7T, 8T, 9T, 13T, 14T, 15T, 16T, 18T, 19T, 20T, 21T, 22T, 23T, 24T • Norwalk (seven): 1T, 2T, 3T, 4T, 6T, 7T, 9T • Bunker Hill (one): 1T • Glenbrook (three): 4T, 9T, 1887 line • Norwalk (two): 5T, 8T
Western Massachusetts Electric Over-dutied Circuit Breaker Replacement • West Springfield (six): 1544 line, 8C-1T-2, 8C-2T-2, 8C-6T-2, 8C-3T-2, 1311 line • Clinton (two): 1T, 2T • East Springfield (two): 2T, 3T
Brayton Substation Reliability Modifications • Brayton Point 345 kV and 115 kV protection upgrades; includes construction of new control house
Stamford Area Reliability Reinforcements • Re-conductor 115 kV 1880 line Rowayton Junction – Glenbrook • Re-conductor 115 kV 1890 line Ely Avenue – Glenbrook
Barbour Hill Area Reliability Reinforcement • Barber Hill re-conductoring and installation of the 3rd line into the area

Project Description
Connecticut/SWCT Reliability Reinforcements • Replace the double circuit tower on the 345 kV Millstone-Southington 348 line and the 345 kV Scovill Rock-East Shore 387 line at Black Pond Junction • Southington and Frost Bridge 115 kV capacitor bank • Rebuild Glenbrook 115 kV substation • Build new 115 kV line from Frost Bridge to Walnut Hill Junction • Re-conductor 115 kV Farmington – Newington 1783 line • Re-conductor 115 kV Old Town – Norwalk 1720/1730 lines • Replace existing transformers at the Ansonia substation with load tap changing (LTC) transformers • Establish a Metro North 115/27.6 kV substation • Upgrade 1710/1730 115 kV cables • Upgrade Baird to Congress 115 kV line • New Trumbull Junction 115/13.8 kV substation • New Southport 115/13.8 kV substation • Grand Avenue – West River 115 kV cable upgrade • 69kV Falls Village area conversion to 115kV
NSTAR Reliability Reinforcements • Mystic capacitor • Re-conductor Waltham to Sudbury 115 kV line 282-507 • Re-conductor 115 kV Auburn Street – Kingston line 191
Second New Brunwick Tie Project • Point Lepreau to Orrington – new 345 kV line
Maine CMP Reliability Reinforcements • Add 115/34.5 kV transformer at Spring Street substation • Convert Maguire Road to a switching substation by replacing switches with breakers • Add 115/34.5 kV transformer at Raymond substation on Section 208/209 • Establish a new Old Orchard Beach 115/34.5 kV substation and 115 kV line • Highland: Add 115 kV breaker • Add 115 kV line from Spring Street substation to Sewall substation • Establish a new Fore River 115/12 kV substation tapping Section 275
Rhode Island Reliability Reinforcements • Install new 345/115 kV autotransformer in SEMA/RI (e.g. Kent County, West Farnum)

Middletown Area Reliability Reinforcements
• Haddam 345/115 kV autotransformer
  • 40 MVAR capacitor banks at Haddam and Branford
  • Rebuild Manchester – Hopewell 1767 line
  • Rebuild East Meriden – North Wallingford 1466 line

Project Description
Eastern Connecticut Reliability Reinforcement • Re-conductor 69 kV Montville – Gails Ferry – Tunnel line (100 – 400) • Brooklyn 345/115 kV autotransformer • Card 345kV circuit breaker • Montville 345kV circuit breaker • Re-terminate the 345-kV Millstone – Manchester 310 line at Card • Rebuild 115kV Card – Wawecus 1080 line
Vermont Long Range Study Projects • Chelsea 115kV Breakers - Replace two SCADA controlled motorized disconnect switches with 115kV circuit breakers at the existing Chelsea substation • Georgia Substation Ring Bus – Rebuild the existing Georgia substation 115kV bus into a ring bus • Burlington 115kV loop – 5.7 miles of new line between two existing substations • Middlesex substation relocation and breaker addition • Bennington to Manchester to Vernon Road 115kV with Manchester 115/46kv substation • Granite to Middlesex 230kV with necessary substation upgrades • Add parallel 115/69 kV transformer on Y25 at Bennington to provide backup
The Braintree Electric Light Department (BELD) Transmission Facilities • 18.4 Applications BELD-02-T01, BELD-02-T02, and BELD-02-X01 for the closing of the 115 kV Braintree loop at the Middle Street Substation #10 in Braintree, Massachusetts to improve the Braintree system reliability, with an in service date of June 2003, as detailed in Mr. H. Joseph Morley's November 22, 2002 transmittal to Mr. Richard Burke. The project consists of: a) Closing the Braintree 115 kV loop at Middle Street Substation #10 in Braintree, Massachusetts by closing circuit breaker #102. (BELD-02-T01) b) At the Potter Station, installation of a 115 kV, three (3) ohm series reactor inserted in the Station ring bus between Breaker #162 and Cable 115-10-16, operation of breaker #164 as normally open and to only be operated closed when the BELD 115 kV loop is open at another station, and installation of a 115 kV circuit switcher to isolate the Potter units GSU when the units are not on-line, to reduce power flows through the Braintree loop and on NSTAR line 478-509 between Grove Street Substation and Holbrook. (BELD-02-T02) c) Installation of a second high-speed protection group, on BELD cable 115-9-4 between Grove Street and Plain Street Substations in Braintree, Massachusetts with the high-speed protection groups at both the Grove Street and Plain Street Substation being independent in accordance with NPCC criteria, to eliminate area stability concerns. (BELD-02-X01)

SCHEDULE 12C

Determination of Localized Costs
On and After January 1, 2004

Introduction

The purpose of this Schedule 12C is to describe procedures that the System Operator will use in determining Localized Costs for RBUs and RTEP02 Upgrades on or after January 1, 2004.

Review and Approval

These Schedule 12C review and approval procedures are separate and distinct from any other approval procedures within the Agreement and are not a condition for receiving approval under any other section of the Agreement. If submission of a proposed plan for a Transmission Upgrade by a Participant for review pursuant to Section 18.4 of the Agreement (or the equivalent of such section as may be adopted under successor documents governing the regional transmission system in New England) is required, then the approval for Transmission Upgrade cost allocations as described under this Schedule 12C of the Tariff cannot occur sooner than after that review has been completed and it has been determined, pursuant to Section 18.4 of the Agreement (or the equivalent of such section as may be adopted under successor documents governing the regional transmission system in New England) that the Participant is free to proceed with implementation of the proposed Transmission Upgrade.

Entities conducting transmission system studies shall review and discuss transmission design and construction alternatives as they are developed under a System Impact Study ("SIS") or as part of the NEPOOL Transmission Plan with the System Operator, Reliability Committee and the Transmission Expansion Advisory Committee, as deemed appropriate by the System Operator.

1. Review Procedures For Determining Localized Costs

Every RBU and RTEP02 Upgrade shall be reviewed by the System Operator with advisory input from the Reliability Committee to determine if any of the costs associated with such upgrade are Localized Costs, except that a proposed Transmission Upgrade which costs less than $500,000 may be exempted from this review by the System Operator. The System Operator, with advisory input from the Reliability Committee, will review and update, as appropriate, the $500,000 threshold on an annual basis.

The Participant seeking cost recovery for a proposed Transmission Upgrade, including reconstruction or replacement, shall submit to the System Operator and the Reliability Committee the following information as deemed appropriate by the System Operator:

(a) A description of (i) the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered, and (ii) the most currently available study grade or better estimates of the construction, including the potential impact on the bulk power system during the construction of such upgrade, and (iii) the operating costs of the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered.

(b) A summary of the technical analysis performed for the Transmission Upgrade and the identified transmission alternatives.

(c) A review and discussion of the need for the proposed Transmission Upgrade.

(d) A discussion of why the requested Transmission Upgrade was selected over other transmission alternatives, with a description of the benefits of the proposed Transmission Upgrade over other transmission alternatives from an operational, timing of implementation, cost and reliability perspective.

If in reviewing the application and associated information, the System Operator, with advisory input from the Reliability Committee, decides that additional information, review, or study is required prior to acting on the application, the System Operator, with advisory input from the Reliability Committee, may elect to defer action and solicit supplementary information, review, or study as required. Sources for such additional information may be, but are not limited to, the entity sponsoring the application, Transmission Owners, and the Reliability Committee.

The System Operator shall determine what those reasonable requirements are that are 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 System Operator will consider, in accordance with Schedule 12C of this Tariff, the reasonableness of the proposed design and construction method with respect to (i) Good Utility Practice, (ii) the current engineering design and construction practices in the area in which the Transmission Upgrade is built, (iii) alternate feasible and practical Transmission Upgrades and (iv) the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrades. The costs of Transmission Upgrades that exceed those reasonable requirements, as determined above, shall be deemed Localized Costs. Local siting requirements for transmission facilities shall not be dispositive of whether or not Localized Costs exist with respect to any particular Transmission Upgrade.

The System Operator is authorized to develop detailed procedures to fulfill the objectives and requirements of this Schedule 12C.

2. Additional Transmission Upgrade Costs or Design Changes Subsequent to the System Operator's Determination of Localized Costs

If the costs associated with a Transmission Upgrade exceed the estimated Pool-Supported PTF costs determined in the original Localized Costs review by ten percent, or the design associated with the construction of a Transmission Upgrade is materially changed subsequent to the System Operator's determination of Localized Costs, then the applicant for Pool-Supported PTF costs shall be required to submit its Transmission Upgrade again to a review by the System Operator to determine if any of the incremental costs or costs associated with the change in design are Localized Costs.

3. Dispute Resolution Regarding Determination of Localized Costs

The System Operator's determination of Localized Costs under the Tariff shall take effect on the date on which the System Operator issues its written findings and determination. The applicant for cost recovery (the "Applicant") whose project is deemed to include Localized Costs may dispute such decision by the System Operator by submitting within 60 days of such decision formal written notice of the dispute to the System Operator, describing in detail the basis for its challenge of the System Operator's determination. The Applicant and the System Operator shall then enter into good faith negotiations for a period not to exceed 60 days from the date of the Applicant's written notice to try to resolve the dispute.

If there is no satisfactory resolution of the dispute at the end of the negotiation period, the Applicant shall then have the right to file a Section 206 complaint with the Commission.

APPENDIX A

RULES FOR DETERMINING INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

Effective June 1, 1998

* The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the NEPOOL Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section 15.1 of the Agreement (or the equivalent of such Section 15.1 as may be adopted under successor documents governing the regional transmission system in New England) shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in Sections 15.1 or 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England), shall remain classified as PTF for all purposes under the Agreement and this Tariff.

ATTACHMENT 4

Sheet No.

Sheet No.

Sheet No.

Sheet No.

Sheet No.

Sheet No.

1.21 **Economic Upgrade**: ~~Those additions~~ Thoseadditions and upgrades that are not related to the interconnection of a generator, and, in the System Operator's determination, are designed to reduce ~~or eliminate Congestion Cost, where the net present values of the reduction in, or elimination of, Congestion Cost exceeds~~ 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 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.

1.22 **Elective Transmission Upgrade**: ~~An addition to or modification of the NEPOOL Transmission System that is not:~~ is a Transmission Upgrade that is participant funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Economic Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the System Operator in accordance with Section 50.2 on a date after the addition or modification already has been otherwise identified in the current NEPOOL Transmission Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

~~**application. An Elective Transmission Upgrade may increase transfer capability of the NEPOOL Transmission System, may increase the reliability or stability of the NEPOOL Transmission System above the requirements and criteria established by NERC, NPCC or the NEPOOL Reliability Committee, or may reduce Congestion Costs into Load Zones or at Nodes into or within the NEPOOL Control Area.**~~

1.31 **Firm Transmission Service:** Service for Native Load Customers, firm Regional Network Service (Network Integration Transmission Service), service for Excepted Transactions and certain other transactions listed in Attachment G-3, Firm Internal Point-To-Point Transmission Service, or Firm MTF Service.

1.32 **FTR Auction:** The periodic auction of FTRs conducted by the ISO in accordance with Section 7 of Market Rule 1.

1.32A **Generator Interconnection Related Upgrade**: An addition to or modification of the NEPOOL Transmission System pursuant to Section 50.1 to effect the interconnection of a new generating unit or an existing generating unit whose capacity is being materially changed and increased, whether or not the interconnection is being effected to meet the Minimum Interconnection Standard. As to Category A Projects (as defined in Schedule 11), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Minimum Interconnection Standard for which the Generator Owner has committed to pay prior to October 29, 1998.

1.33 **Generator Owner:** The owner, in whole or part, of a generating unit whether located within or outside the NEPOOL Control Area.

1.34 **Good Utility Practice:** Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region.

1.42A **Local Benefit Upgrade(s) ("LBUs"):** a 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 Section 15.1 of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England).

1.43 **Local Network:** The transmission facilities constituting a local network identified on Attachment E, and any other local network or change in the designation of a Local Network as a Local Network which the Participants Committee may designate or approve from time to time. The Participants Committee may not unreasonably withhold approval of a request by a Participant that it effect such a change or designation.

1.44 **Local Network Service:** Local Network Service is the service provided, under a separate tariff or contract, by a Participant that is a Transmission Provider to another Participant or other entity connected to the Transmission Provider's Local Network to permit the other Participant or entity to efficiently and economically utilize its resources to serve its load.

1.45 **Local Point-To-Point Service:** Local Point-To-Point service is Point-To-Point Transmission Service provided, under a separate tariff or contract, by a

Participant that is a Transmission Provider over Non-PTF or distribution facilities to permit deliveries to or from an interconnection point on the PTF.

1.45A **Localized Costs:** the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the System Operator 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 System Operator will consider, in accordance with Schedule 12C of this Tariff, 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, efficiency and reliability of the proposed Transmission Upgrade. Prior to any recovery of costs under this Tariff associated with a RTEP02 Upgrade or a Regional Benefit Upgrade, the System Operator, 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 System Operator shall identify them in the NEPOOL Transmission Plan.

1.46 **Locational Marginal Price (LMP):** Is as defined and calculated pursuant to Market Rule 1.

1.56 Native Load Customers: The wholesale and retail power customers of a Participant or other entity which is a Transmission Provider on whose behalf the Participant or other entity, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

1.57 NEMA or "Northeast Massachusetts" Upgrade: Is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that is not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section 18.4 of the Restated NEPOOL Agreement; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of this Tariff.

1.58 NEPOOL: The New England Power Pool, the power pool created under and governed by the Agreement, and the entities collectively participating in the New England Power Pool.

1.59 NEPOOL Control Area: The Control Area (as defined in Section 1.11) for NEPOOL.

of the unit shall be limited in accordance with Section 49, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the NEPOOL Control Area for so long as any Participant has an Ownership Share in the resource or resources which is being delivered to it in the NEPOOL Control Area to serve Network Load located in the NEPOOL Control Area or other designated Network Loads contemplated by Section 43.3 of this Tariff taking Regional Network Service. (2) With respect to Non-Participant Network Customers, any generating resource owned, purchased or leased by the Network Customer which it designates to serve Network Load.

1.71 **~~Network Upgrades: Modifications or additions to transmission-related facilities that are integrated with and support the overall PTF for the general benefit of all users of the PTF.~~[Deleted.]**

1.72 **Node:** Is as defined pursuant to Market Rule 1.

1.73 **Non-Firm Point-To-Point Transmission Service:** Point-To-Point Transmission Service under this Tariff that is subject to Curtailment or Interruption under the circumstances specified in Section 28.7 of this Tariff.

1.74 **Non-Participant:** Any entity that is not a Participant.

1.97 **Pre-1997 PTF Rate:** The transmission rate of a Participant determined in accordance with paragraph (5) of Schedule 9 to this Tariff.

1.98 **Qualified Upgrade Award:** Is as defined and determined pursuant to Market Rule 1.

1.99 **Reactive Supply and Voltage Control From Generation Sources Service:** This service is the form of Ancillary Service described in Schedule 2.

1.100 **Real-Time Energy Market:** Is as defined and determined pursuant to Market Rule 1.

1.101 **Receiving Party:** The entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under this Tariff.

1.101A **Regional Benefit Upgrade(s) ("RBU(s)"):** a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in Section 15.1 of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England); and (iii) is included in the NEPOOL Transmission Plan as either a Reliability Upgrade or an Economic Upgrade identified as needed pursuant to Section 51 of this Tariff. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of this Tariff (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115 kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in Section 15.1 or Section 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England).

1.102 **Regional Network Service:** The transmission service over the PTF described in Part II and Part VI of this Tariff.

1.103 **Regulation and Frequency Response Service:** This service is the form of Ancillary Service described in Schedule 3.

amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Upgrades.

1.107 **Reserved Capacity:** The maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the PTF or MTF between the Point(s) of Receipt and the Point(s) of Delivery under Part V or Schedule 18 of this Tariff. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis.

1.108 **Resource:** Is as defined pursuant to Market Rule 1.

1.108A **RTEP02 Upgrade(s):** a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by the System Operator's Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by the System Operator. The RTEP02 Upgrades are listed in Schedule 12B of this Tariff.

1.109 **Scheduling, System Control and Dispatch Service:** This service is the form of Ancillary Service described in Schedule 1.

1.110 Second Effective Date: The date on which the provisions of Part Three of the Agreement (other than the Installed Capability Responsibility provisions of Section 12) shall become effective and shall be such date as the Commission may fix on its own or pursuant to a request of the Participants Committee.

1.111 Service Agreement: The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the System Operator for service under this Tariff.

1.112 Service Commencement Date: The date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with Section 29.3 or Section 41.1 under this Tariff, or in the case of Regional Network Service which is not required to be furnished under a Service Agreement pursuant to Section 48 of this Tariff, the date service actually commences.

1.113 SMD Effective Date: Is as defined and determined pursuant to Market Rule 1.

1.114 System Impact Study: An assessment pursuant to Part V, VI or VII of this Tariff of (i) the adequacy of the NEPOOL Transmission System to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or Internal Point-To-Point Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

to the reciprocity requirements specified in the Tariff, or an individual such Participant, whichever is appropriate.

1.124A **Transmission Upgrade(s):** an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of this Tariff governing rates and service on the PTF on or after January 1, 2004. The categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of this Tariff.

1.125 **Use:** For a Transmission Customer which has exercised its option to take Internal Point-To-Point Service to serve all or a portion of its load at any Point of Delivery, the greatest for the hour of (i) the maximum amount that it will receive in the hour, as determined from meters and adjusted for losses, at that Point of Delivery from the resources covered by its Completed Applications and from Interchange Transactions, or (ii) the portion of its Installed Capability Responsibility (as determined in accordance with the Agreement) for the month which must be satisfied at that Point of Delivery with such resources if the Transmission Customer is a Participant, or (iii) the portion of its Operable Capability Responsibility (as determined in accordance with the Agreement) for the hour which must be satisfied at that Point of Delivery with such resources if the Transmission Customer is a Participant, or (iv) the amount of capacity from such resources that the Transmission Customer must receive, adjusted to include losses, at such Point of Delivery for the hour to meet its reliability obligations if the Transmission Customer is a Non-Participant. Use shall be expressed in terms of whole Kilowatts on a sixty-minute interval (commencing on the clock hour) basis.

4.9 Special Constraint Resource Service: The rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 19 of this Tariff and Market Rule 1.

5 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding the NEPOOL Open Access Same-Time Information System and standards of conduct are set forth in 18 C.F.R. §37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities). In the event available transmission capability, as posted on OASIS, is insufficient to accommodate a request for Firm Internal Point-To-Point Service, for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or an Elective Transmission Upgrade, additional studies may be required as provided by this Tariff pursuant to Sections 33, 44 and 50.

6 Local Furnishing and Other Tax-Exempt Bonds

6.1 Participants That Own Facilities Financed by Local Furnishing or Other Tax-Exempt Bonds: This provision is applicable only to Participants that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local

33.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study agreement shall clearly specify the System Operator's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the System Operator and any affected Participants will rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer shall not be assessed a charge for such existing studies; however, the Eligible Customer shall be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the PTF and indirectly affected MTF of the customer request for Internal Point-To-Point Service or for an Elective Transmission Upgrade.

(ii) If in response to multiple Eligible Customers requesting a similar study in relation to the same competitive solicitation, a single System Impact Study is sufficient for the System Operator to accommodate the requests, the costs of that study will be equitably prorated among the Eligible Customers.

completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required ~~Network Upgrades~~ upgrades, modifications or additions to the PTF, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the affected Transmission Provider(s) or other entities that will be responsible for the construction of the new facilities or upgrades equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

In addition to the foregoing, each Facilities Study performed on or after the SMD Effective Date shall, if requested by the Transmission Customer, contain a non-binding estimate from the System Operator of the Qualified Upgrade Awards, if any, resulting from the construction of the new facilities. After completion of the

46 Rates and Charges

The Network Customer shall pay Transmission Providers for any Direct Assignment Facilities and its share of the cost of any required ~~Network Upgrades~~ upgrades, modifications or additions to the PTF and applicable study costs consistent with Commission policy and Schedules 11 and 12, along with the payment to the System Operator of the charges for Ancillary Services and the charge for Regional Network Service provided under this Tariff.

46.1 Determination of Network Customer's Monthly Network Load: The Network Customer's "Monthly Network Load" is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 43.3) coincident with the coincident aggregate load of the Participants and other Network Customers served in each Local Network in the hour in which the coincident load is at its maximum for the month ("Monthly Peak").

47 Operating Arrangements

47.1 Operation under The Network Operating Agreement: The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement including the information identified in subsection (g) below, or for any removal of Upgrades from the Plan pursuant to subsection (c) below.

(c) An Upgrade may be ~~added~~ approved for addition to the NEPOOL Transmission Plan by the System Operator at any time in a given year and in doing so the System Operator may consult with and consider input from the Transmission Expansion Advisory Committee, within the scope of its respective functions as specified in subsection (b) of Section 51.2, and the Reliability Committee within the scope of its function as specified in Section 8.4(a) of the Agreement. Similarly, an Upgrade may be ~~removed~~ approved for removal from the NEPOOL Transmission Plan by the System Operator at any time in a given year if the market responds by proposing alternative generation projects, Merchant Transmission Facilities in accordance with Section 51.8, or demand-side projects, or other circumstances arise such that the need for the Upgrade no longer exists, and in doing so the System Operator may consult with and consider input from the Transmission Expansion Advisory Committee, within the scope of its functions as specified in subsection (b) of Section 51.2, and the Reliability Committee within the scope of its function as specified in Section 8.4(a) of the Agreement; provided that the entity responsible for the construction of the Upgrade is reimbursed for any costs prudently incurred or prudently committed to be incurred in connection with the planning, preparation for construction, and/or construction of the Upgrades ~~proposed for removal~~ removed from the Plan. All Upgrades ~~proposed to be added or removed~~ approved for addition or removal in such interim Plans during this planning process must meet the requirements of subsection (a) of Section 51.3. In the event that the estimated cost of a proposed Upgrade exceeds $20 million (which threshold amount shall be reviewed annually by the System Operator and reset as it reasonably deems appropriate), a member of a subcommittee of the System Operator's Board will attend such meeting at which the ISO will seek the Reliability Committee's advice on the inclusion of the proposed Upgrade into the NEPOOL Transmission Plan. An approval of the interim Plan by the System Operator made pursuant to this subsection (c) shall have the same effect with regard to cost reimbursement and with regard to inclusion or removal of an Upgrade from the Plan as an approval of the Plan made by the System Operator's Board of Directors pursuant to Section 51.4(i) of this Tariff.

(d) The Transmission Owners, those entities requesting transmission service or interconnection, and any other entities proposing to provide facilities to be integrated into the NEPOOL Control Area or alternatives to such facilities shall supply upon request and subject to applicable confidentiality requirements of the NEPOOL Information Policy any information and data reasonably required to prepare a NEPOOL Transmission Plan or to perform a transmission enhancement and expansion study. Any confidential cost estimate for a proposed Upgrade to the PTF that is or may be subject to subsection (a) of Section 51.6 shall be considered by the System Operator to be competitively sensitive, confidential information and shall be considered the estimator's confidential information under the NEPOOL Information Policy, and shall not be disclosed by the System Operator to other entities that may be eligible to submit a proposal in accordance with Section 51.6, including, without limitation, other Transmission Owners. Any other information or data provided shall be subject to the rights and obligations of the NEPOOL Information Policy.

(e) The NEPOOL Transmission Plan shall be developed in coordination with the transmission systems of the surrounding Control Areas and the regional reliability councils, as appropriate.

(f) At the initiation of an effort to update a Plan or develop a new Plan, the System Operator may solicit input for the updated or new Plan from members of the Transmission Expansion Advisory Committee and the Reliability Committee. The Transmission Expansion Advisory Committee shall meet to perform its respective functions in connection with the preparation of the NEPOOL Transmission Plan, as specified in subsection (b) of Section 51.2. Thereafter, drafts of the NEPOOL Transmission Plan shall be provided to the Transmission Expansion Advisory Committee and the Reliability Committee and input from ~~that Committee~~ those committees shall be received and considered by the System Operator in preparing and revising subsequent ~~drafts.~~ plan approvals. Before ~~a final draft of any proposed~~ an interim NEPOOL Transmission Plan is presented to the System Operator's Board of Directors for approval, a subcommittee of that Board shall hold a public meeting to receive input directly and to discuss any proposed revisions to the ~~draft~~ NEPOOL Transmission Plan.

(g) For potential Upgrades proposed to be included in the NEPOOL Transmission Plan, the System Operator (in connection with the preparation of the NEPOOL Transmission Plan) shall identify, to the extent practicable, the anticipated benefits of the proposed Upgrade. To the extent an Upgrade is proposed to reduce ~~Congestion Costs~~ bulk power system costs to load system-wide, the System Operator shall publish data and information, in a manner that does not violate the Information Policy, that would reasonably permit entities to calculate the costs and economic benefits of such an Upgrade and, to the extent feasible, the distribution of such benefits within the region. Such information shall be published so as to permit analysis for a reasonably limited period of time (generally ten years or less), and shall include the effects of (i) all projects for which applications have been received for approval under Section 18.4 of the Restated NEPOOL Agreement, including but not limited to proposed generation projects and Merchant Transmission Facilities and (ii) demand-side projects planned within the NEPOOL Control Area and identified to the System Operator.

(h) Any entity with a representative on the Transmission Expansion Advisory Committee may request that specific proposals for alternative solutions or facilities, including but not limited to generation projects, transmission projects, and/or demand-side projects, be accounted for in the development of the NEPOOL Transmission Plan. The ~~recommended draft of a~~ NEPOOL Transmission Plan shall account for such proposals where appropriate provided that the ~~recommended~~ NEPOOL Transmission Plan shall not include in the list of Upgrades any proposed resource participating in competitive electricity markets or Merchant Transmission Facilities. If a proposal is not accounted for in the ~~draft~~ interim Plan to be recommended to the System Operator's Board of Directors, the recommendation to the Board shall include a written explanation of why such proposal(s) were not accounted for in the ~~recommended~~ interim Plan, which shall be made public.

(i) ~~A draft of a recommended~~ The interim NEPOOL Transmission Plan shall be presented at least annually to the System Operator's Board of Directors for approval. At least every three years, a ~~draft~~ Plan shall reflect the results of a new comprehensive transmission planning and expansion study conducted pursuant to Section 51.5. ~~In other years, the draft may be only an update to a prior approved Plan. The draft~~ The interim Plan shall be presented to the System Operator's Board of Directors no later than September 30 of each year and shall be acted on by the Board within 60 days of receipt. The Board of Directors may approve the ~~recommended~~ interim Plan as submitted, modify the interim Plan or remand all or any portion of it back with guidance for development of a revised ~~recommendation~~ interim Plan in accordance with this Section 51.4. The Board of Directors may consider the Plan in executive session, and shall consider in its deliberations the views of the subcommittee of the

SCHEDULE 12

Reliability Upgrade, Economic Upgrade and Elective Transmission Upgrade Costs

Note: This Schedule 12 shall remain in effect through and including December 31, 2003, to be superseded as hereinafter provided.

(1) Allocation and Recovery of Costs for Reliability Upgrades and Economic Upgrades Associated with the NEPOOL Transmission Plan. All costs of MTF shall be recovered in accordance with the recovery mechanism for those facilities that is filed with and accepted by the Commission. All costs associated with Upgrades for the interconnection of Merchant Transmission Facilities shall be treated in the same fashion and subject to the same rights and obligations as Generator Interconnection Related Upgrade Costs for Category C Projects under Schedule 11 of this Tariff, including the provisions of Sections (5), (6) and (7) of that Schedule, but excluding the provisional clause at the end of the first sentence in Section (5) of Schedule 11. To the extent not otherwise covered above or by Part III or Schedule 11 of the Tariff or Sections (2) or (3) of this Schedule 12 below, the costs of a Reliability Upgrade and Economic Upgrade shall be allocated as follows:

(a) If entities have agreed to bear some or all of the cost responsibility for an Upgrade, the Upgrade costs shall be allocated to such entities in accordance with that agreement.

SCHEDULE 12

Transmission Cost Allocation
On and After January 1, 2004

On January 1, 2004, this Schedule 12 shall supersede in its entirety the version of Schedule 12 that is in effect as of June 25, 2003 ("Current Schedule 12"). Current Schedule 12 shall remain in effect through and including December 31, 2003. This Schedule 12 describes the cost allocation treatment of upgrades, modifications or additions to the transmission system in New England on and after January 1, 2004. Nothing in this Schedule 12 shall eliminate the PTF status of transmission facilities that were PTF on December 31, 2003; and any upgrades to such facilities that continue to meet the definition of PTF specified in Section 15.1 or Section 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) shall be classified as PTF for all purposes under the Agreement and this Tariff.

A. Process for Categorizing Upgrades for Cost Allocation:

Upgrades, modifications or additions to the NEPOOL Transmission System shall be categorized by the System Operator, with advisory input from the Reliability Committee and the Transmission Expansion Advisory Committee, as appropriate. A list of categorized Transmission Upgrades shall be made part of each annual and interim NEPOOL Transmission Plan, subject to the provisions of Section 51 of this Tariff.

B. Transmission Cost Allocation By Category:

1. Generator Interconnection Related Upgrades:

The cost for all Generator Interconnection Related Upgrades shall be allocated pursuant to Schedule 11 of this Tariff.

2. Elective Transmission Upgrades:

The cost for all Elective Transmission Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this Tariff, but shall be allocated solely to the entity or entities volunteering to make and pay for such Elective Transmission Upgrades.

3. NEMA Upgrades:

The cost for all NEMA Upgrades shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades continue to meet the definition of PTF under either Section 15.1 or 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) and allocated to Transmission Customers taking service under this Tariff.

4. RTEP02 Upgrades:

The costs for all RTEP02 Upgrades placed in service on or before December 20, 2007, shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades continue to meet the definition of PTF under either Section 15.1 or 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) and allocated to Transmission Customers taking service under this Tariff.

5. Regional Benefit Upgrades:

The cost for all Regional Benefit Upgrades, as well as all transmission facilities that were PTF as of December 31, 2003 and upgrades to such facilities that meet the definition of PTF under either Section 15.1 or 15.1A (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England), shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades and such existing PTF continue to meet the definition of PTF under either Section 15.1 or 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England) and allocated to Transmission Customers taking service under this Tariff. Economic Upgrades that are not RBUs shall not be included in the Pool-Supported PTF Costs recoverable under this Tariff.

6. Local Benefit Upgrades:

The cost for Local Benefit Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this Tariff.

7. Localized Costs:

Localized Costs shall not be included in the Pool-Supported PTF costs recoverable under this Tariff, but instead the responsibility for Localized Costs related to any RTEP02 Upgrades and any Regional Benefit Upgrades shall be the responsibility of the entity or entities causing or subject to such Localized Costs. The System Operator, in accordance with Schedule 12C of this Tariff, shall review RTEP02 Upgrades and Regional Benefit Upgrades and identify any Localized Costs associated with them.

C. Merchant Transmission Facilities Cost Allocation

The cost of all Merchant Transmission Facilities, including the cost of Transmission Upgrades required to interconnect the Merchant Transmission Facilities to the PTF, shall be the responsibility of the developer of the Merchant Transmission Facilities, and shall not be included in the Pool-Supported PTF costs recoverable under this Tariff.

SCHEDULE 12A

NEMA Upgrades

A "Northeast Massachusetts Upgrade" is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section 18.4 of the Restated NEPOOL Agreement; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. The aggregate capital costs of the Northeast Massachusetts Upgrades which qualify as Pool-Supported PTF costs shall not exceed $35,000,000. A general description of the projects which constitute the NEMA Upgrades is provided in the list below.

1. Framingham 230/115kV autotransformer and breaker replacement
2. Upgrade Framingham to West Medway 230 kV line (240-601)
3. Add Mystic 345kV breaker #101S
4. West Walpole 345/115kV autotransformer and breaker replacement
5. Rebuild Speen Street to Sudbury 115kV line (342-507) and replace breakers at both ends
6. Waltham 230/115kV autotransformer and breaker replacement
7. Upgrade Waltham to West Medway 230 kV line (282-602)
8. Upgrade Framingham to Speen Street 115kV line (433-507) and replace breakers at Framingham
9. Add a third Waltham 115kV phase shifting transformer
10. Upgrade Sherborn 115kV station equipment
11. Merrimack (New Hampshire) 230/115kV autotransformer replacement

SCHEDULE 12B

RTEP02 Upgrades

Following is a general description of projects which constitute the RTEP02 Upgrades.

Project Description
New Brunswick – New England Tie Performance Enhancement • Series compensation
MEPCO Special Protection Systems Alternative • Alternative 1: Decommission existing SPS and install new direct logic sensing Transfer Trip SPS. • Alternative 2: Extend time delay on existing flow based SPS and install new direct logic sensing Transfer Trip SPS. • Alternative 3: Decommission existing SPS and install new direct logic sensing Transfer Trip SPS with fault discrimination.
Bangor Hydro Electric Down East Transmission Reliability Improvement • New transmission path between Rebel Hill and the Epping/Washington County area • Reconfiguration of existing facilities.
CMP Autotransformer-Outage Reliability Improvement • Review/mitigation of 120°F sag limits. • Mitigation of line overloading that limits select pockets of generation. • Mitigation of low voltages that may be improved with implementation of the new Maine Voltage Operating Guide and capacitor bank additions.
Maine and New Hampshire Voltage Enhancements • Install 24 MVAR capacitors at Sanford 115 kV substation • Add 50 MVARs of capacitors at Ocean Road and Madbury • Add 60 MVARs of capacitors at Three Rivers • Add 170 MVARs of capacitors at Maxcys and western Maine
Maine – New Hampshire Transfer Capability Short Term Enhancements • Schiller to Bolt Hill 115 kV N133 line upgrade • Quaker Hill to Three Rivers 115 kV 197 line upgrade • Maguire to Three Rivers 115 kV 250 line upgrade • Alternate project: Southern Maine substation re-configuration or series reactor

Project Description
Requirements for Closing PSNH's Y138 Line – Saco Valley to White Lake • Saco Valley 115 kV breaker additions • 120 MVAR of shunt reactive compensation is needed between the Maine and New Hampshire ends of the transmission system • Series reactor overload mitigation system is needed on the New Hampshire end of the Beebe to White Lake 115 kV B112 line • Alternative: Beebe 115kV phase shifter • Beebe substation terminal equipment upgrades on B112 line to change out circuit breaker, disconnect switches, bus work and secondary equipment • Re-rate 28 miles of 115 kV Section 214 transmission line from Kimball Road to Harrison and Lovell in Maine • White Lake 115kV capacitor
Southern New Hampshire Reinforcements • Rebuild Scobie 115 kV substation to breaker and a half arrangement • Re-conductor Deerfield to Garvins 115 kV G146 line • Add a second 345/115 kV 400 MVA autotransformer at Scobie substation • Add a second 345/115 kV 400 MVA autotransformer at Deerfield substation • Add three 50 MVAR capacitor banks at the Deerfield 115 kV substation • Deerfield dynamic voltage control • New 115 kV line from Reeds Ferry – Huse Road • Upgrade Greggs 115 kV substation • Upgrade Merrimack 115 kV substation • Add Amherst 345 kV 4 – breaker ring bus • Add six 50 MVAR capacitor banks at the Scobie 115 kV substation • Re-terminate Deerfield autotransformer and/or second breaker • Re-conductor two 115 kV circuits from Schiller – Scobie (U181/H141 and E194/R193) • Alternatives considered: o Newington 345/115 kV autotransformer o Coburn Road 345/115 kV autotransformer o Rebuilding the 115 kV Deerfield – Laconia D140 line
Northwest Vermont Near-term Voltage Reinforcement • Essex Capacitors, two 24.75 MVAR 115 kV banks
Rutland Reliability Project • Energize existing Coolidge-West Rutland line at 345 kV • Add two West Rutland 345/115 kV transformers • Add three 345 kV circuit breakers at Coolidge • Add three 115 kV circuit breakers at West Rutland • Add two 24.75 MVAR 115 kV capacitor banks at Coolidge

Project Description
Northwest Vermont Reliability Project • New Haven-West Rutland 345 kV line and 345/115 kV New Haven substation with 115 kV ring bus • Granite 230 kV PAR, 25 MVAR capacitor bank and breaker additions • 150 MVAR STATCOM at Granite • Blissville 115 kV PAR • New Haven-Vergennes-Queen City 115 kV line • Hartford 115 kV breaker – Add an existing 115 kV motorized SCADA controlled disconnect switch with a circuit breaker at Hartford substation on the line toward the Chelsea substation • Granite to Middlesex 230 kV • Addition of 230/115 kV and 345/115 kV autotransformers • Addition of breakers and shunt devices
Vermont Northern Loop Project • New Irasburg – Newport 115 kV line ("northern loop") operated synchronous with VELCO (7 miles of new 115/46kV double circuit construction) • New 115 kV breaker at St. Johnsbury • Two new 115 kV breakers at Irasburg • New five breaker 115 kV ring bus at Highgate • St Albans Line reconfiguration and substation upgrade-Reconfigure St Albans lines and breakers to replace the single 115kV tap line with two "in and out" lines

Monadnock Regional Reinforcement
• Addition of switched capacitor banks at Chestnut Hill 115 kV bus
• Potential alternatives:
    o New Fitzwilliam 345/115 kV substation north of Flagg Pond tapped onto the Scobie Pond – Vermont Yankee 345 kV 379 line and separation of the existing lines between Flagg Pond and Pratts Junction.
    o (Third) Pratts Junction to Flagg Pond 115 kV line

Greater Metro-West Transmission Supply Study • Install tie breaker and second radial Northborough – Hudson 115 kV line • Re-conductor Woodside-Northborough / Fitch Rd 69 kV W-23 line • Millbury 115 kV 63 MVAR Capacitor Bank • Northborough 115 kV 54 MVAR Capacitor Bank • Fitch Road – Rebuild 69 kV station • Re-conductor Fitch Rd to Pratts Junction 69 kV N40 line • Install Woodside 69 kV breaker

Project Description
Central Massachusetts Reliability Reinforcement • Re-conductor V174 Carpenter Hill to Millbury 115 kV • Install new 345/115 kV autotransformer in Central Massachusetts (e.g. Pratts Junction, Millbury) • Install second Wachusett 115/69 kV autotransformer • Pratts Junction 115/69/13.8 kV transformer replacement
Springfield/Western Massachusetts Reliability Reinforcements • Improve sag clearances on the 115 kV Blandford – Pleasant 1421 line • Pleasant 115 kV capacitor bank • As determined by study
NEMA/Boston Short-term Reliability Reinforcements Potential North Shore upgrades include: • B154N/C155N Ward Hill to Salem Harbor 115 kV line upgrades (re-sag/re-conductor) • Second Ward Hill 345/115 kV transformer • Completion of the Golden Hills 345 kV ring bus • Split up switching of Mystic-Golden Hills 345 kV cables (348X+Y) • F-158N and Q-169 Golden Hills to Everett and to Lynn 115 kV line upgrades • Other 115 kV line upgrades
NEMA/Boston Long-term Reliability Reinforcements Potential upgrades include: • Mystic-K Street-Kingston 345 kV loop • Other 345 kV and/or 115 kV line upgrades • Build 345 kV line from Scobie to Tewksbury
Norwood Municipal Light Department Reliability Reinforcements • Install two new 115 kV underground lines to Norwood's new Ellis Avenue substation (2.2 miles each) • Construct new Ellis Avenue substation (4-breaker ring distribution station with two transformers rated 55 MVA each) • Modify existing Dean Street substation

Project Description
Auburn Area Reliability Reinforcements • Re-tension (upgrade) E20 115 kV line from Auburn Street to L1 tap • Re-conductor F19 115 kV line from Bridgewater to S1 tap (4.1 miles) • Re-conductor G18 115 kV line from Bridgewater to Dupont (7.6 miles) • Replace bus work, wave trap, and change current transformer ratios at Dupont • Replace wave trap at Bridgewater • Re-tension (upgrade) C2 115 kV from Auburn Street to Dupont • Replace wave traps at both the Auburn Street and Dupont • Upgrade bus work at Dupont • Re-tension (upgrade) A94 115 kV line from Auburn Street to Parkview • Re-tension (upgrade) S1 115 kV line from Belmont Tap to Belmont • Upgrade bus work at Belmont • Re-tension E20 115 kV line from Bridgewater to L1 tap • Install new 115 kV circuit breaker between Auburn Street 345/115 kV autotransformer and the bus tie that connects the north and south 115 kV buses at Auburn Street
Cape Cod Supply Study • Canal to Bourne #120 115 kV line (string a second Canal – Bourne 115 kV line on the existing Canal to Bourne 115 kV double circuit structures) • Canal to Oak #399 345 kV line (convert existing #120 115 kV line to 345 kV operation) • Install 345/115 kV autotransformer at Oak Street • Add one 80 MVAR capacitor bank, STATCOM or SVC at the 115 kV Barnstable station • Expand the Canal 345 kV substation with a 3rd two-breaker bay

SEMA/RI Short-term Export Enhancement
• Upgrade 345 kV circuit breaker 314 Millbury substation to provide IPT capability
• Upgrade 345 kV circuit breaker 142 Sherman Road substation to provide IPT capability
• Replace West Walpole 104, 105, 108, 109 with IPT breakers
• Re-wire West Medway 111, 112 to IPT
• Potential upgrades to or replacements of breakers at
  o Canal
  o Brayton Point

Original Sheet No. 229N

Project Description
SEMA/RI Long-term Export Enhancement Potential major 345 kV long-term system enhancements • Card – West Farnum – Sherman – Millbury 345 kV • Card – West Farnum – Sherman – Millbury 345 kV tapping the Millstone to Manchester 345 kV line at Card • Montville – Kent – West Farnum – Millbury 345 kV • Other major 345 kV enhancements that link SEMA/RI to the NEMA/Boston area
Northwest Connecticut Import Capability Enhancements • Upgrade Canton-North Bloomfield terminal equipment (associated with the 1784 line) • Add 40 MVAR of capacitors at Franklin Drive • Add 50 MVAR of capacitors at Canton • Re-conductor Canton-Weingart 115 kV line 1732 (with 1272 conductor)
Norwalk-Stamford Area Glenbrook Static VAR Compensator • Add 150 MVAR statcom at the Glenbrook substation • Add three 50 MVAR 115 kV fixed capacitor banks at the Glenbrook substation • Re-terminate the 115 kV Darien-South End 1977 line at the Glenbrook substation
Southwest Connecticut Reliability Reinforcement • Build new 345 kV line from Plumtree to Norwalk • Build new 345 kV line from Devon to Trumbull Junction • Build new 345 kV line from Trumbull Junction to Norwalk • Build new 345 kV line from Devon to Beseck • Build new 345 kV line from Trumbull Junction to Pequonnock • Build new 345 kV cable from Norwalk to Glenbrook • Add new 345 kV substations at Plumtree, Norwalk, Pequonnock, Devon and Beseck Junction • Add 3-150 MVA (or larger) autotransformers at Norwalk (one), Pequonnock (one), Devon (one) and Glenbrook (one) • Add one 3-200 MVA autotransformers at Pequonnock to shift output from Bridgeport Energy to the 345 kV • Establish new 115 kV substation adjacent to Devon (East Devon) • Other 115 kV work all with new 345 kV structures • Build new 115 kV cable from Glenbrook to Norwalk Harbor • Add series reactor at Ash Creek
Norwalk Harbor to Northport 138 kV (1385) Replacement • Replace 138 kV Norwalk (CT) – Northport (NY) 1385 cable with three (3-phase) cables insulated with a solid dielectric.

Project Description
East-West Oscillation Mitigation Alternatives include: • Reduce transfers from New Brunswick to New England • Control unit dispatch in Maine • Add power system stabilizers to key units in New England • Determine interdependence with other concurrent system transfers
Connecticut Light & Power Over-dutied Circuit Breaker Replacement • Frost Bridge (one): 10K-2 • Glenbrook (four): 2T, 7T, 1753 line, 1792 line • Hanover (one): 1355 line • Manchester (three): 14T, 15T, 10K-2 • Montville (fourteen): 7T, 8T, 9T, 13T, 14T, 15T, 16T, 18T, 19T, 20T, 21T, 22T, 23T, 24T • Norwalk (seven): 1T, 2T, 3T, 4T, 6T, 7T, 9T • Bunker Hill (one): 1T • Glenbrook (three): 4T, 9T, 1887 line • Norwalk (two): 5T, 8T
Western Massachusetts Electric Over-dutied Circuit Breaker Replacement • West Springfield (six): 1544 line, 8C-1T-2, 8C-2T-2, 8C-6T-2, 8C-3T-2, 1311 line • Clinton (two): 1T, 2T • East Springfield (two): 2T, 3T
Brayton Substation Reliability Modifications • Brayton Point 345 kV and 115 kV protection upgrades; includes construction of new control house
Stamford Area Reliability Reinforcements • Re-conductor 115 kV 1880 line Rowayton Junction – Glenbrook • Re-conductor 115 kV 1890 line Ely Avenue – Glenbrook
Barbour Hill Area Reliability Reinforcement • Barber Hill re-conductoring and installation of the 3rd line into the area

Project Description
Connecticut/SWCT Reliability Reinforcements • Replace the double circuit tower on the 345 kV Millstone-Southington 348 line and the 345 kV Scovill Rock-East Shore 387 line at Black Pond Junction • Southington and Frost Bridge 115 kV capacitor bank • Rebuild Glenbrook 115 kV substation • Build new 115 kV line from Frost Bridge to Walnut Hill Junction • Re-conductor 115 kV Farmington – Newington 1783 line • Re-conductor 115 kV Old Town – Norwalk 1720/1730 lines • Replace existing transformers at the Ansonia substation with load tap changing (LTC) transformers • Establish a Metro North 115/27.6 kV substation • Upgrade 1710/1730 115 kV cables • Upgrade Baird to Congress 115 kV line • New Trumbull Junction 115/13.8 kV substation • New Southport 115/13.8 kV substation • Grand Avenue – West River 115 kV cable upgrade • 69kV Falls Village area conversion to 115kV
NSTAR Reliability Reinforcements • Mystic capacitor • Re-conductor Waltham to Sudbury 115 kV line 282-507 • Re-conductor 115 kV Auburn Street – Kingston line 191
Second New Brunwick Tie Project • Point Lepreau to Orrington – new 345 kV line
Maine CMP Reliability Reinforcements • Add 115/34.5 kV transformer at Spring Street substation • Convert Maguire Road to a switching substation by replacing switches with breakers • Add 115/34.5 kV transformer at Raymond substation on Section 208/209 • Establish a new Old Orchard Beach 115/34.5 kV substation and 115 kV line • Highland: Add 115 kV breaker • Add 115 kV line from Spring Street substation to Sewall substation • Establish a new Fore River 115/12 kV substation tapping Section 275
Rhode Island Reliability Reinforcements • Install new 345/115 kV autotransformer in SEMA/RI (e.g. Kent County, West Farnum)
Middletown Area Reliability Reinforcements • Haddam 345/115 kV autotransformer • 40 MVAR capacitor banks at Haddam and Branford • Rebuild Manchester – Hopewell 1767 line • Rebuild East Meriden – North Wallingford 1466 line

Project Description
Eastern Connecticut Reliability Reinforcement • Re-conductor 69 kV Montville – Gails Ferry – Tunnel line (100 – 400) • Brooklyn 345/115 kV autotransformer • Card 345kV circuit breaker • Montville 345kV circuit breaker • Re-terminate the 345-kV Millstone – Manchester 310 line at Card • Rebuild 115kV Card – Wawecus 1080 line
Vermont Long Range Study Projects • Chelsea 115kV Breakers - Replace two SCADA controlled motorized disconnect switches with 115kV circuit breakers at the existing Chelsea substation • Georgia Substation Ring Bus – Rebuild the existing Georgia substation 115kV bus into a ring bus • Burlington 115kV loop – 5.7 miles of new line between two existing substations • Middlesex substation relocation and breaker addition • Bennington to Manchester to Vernon Road 115kV with Manchester 115/46kv substation • Granite to Middlesex 230kV with necessary substation upgrades • Add parallel 115/69 kV transformer on Y25 at Bennington to provide backup
The Braintree Electric Light Department (BELD) Transmission Facilities • 18.4 Applications BELD-02-T01, BELD-02-T02, and BELD-02-X01 for the closing of the 115 kV Braintree loop at the Middle Street Substation #10 in Braintree, Massachusetts to improve the Braintree system reliability, with an in service date of June 2003, as detailed in Mr. H. Joseph Morley's November 22, 2002 transmittal to Mr. Richard Burke. The project consists of: a) Closing the Braintree 115 kV loop at Middle Street Substation #10 in Braintree, Massachusetts by closing circuit breaker #102. (BELD-02-T01) b) At the Potter Station, installation of a 115 kV, three (3) ohm series reactor inserted in the Station ring bus between Breaker #162 and Cable 115-10-16, operation of breaker #164 as normally open and to only be operated closed when the BELD 115 kV loop is open at another station, and installation of a 115 kV circuit switcher to isolate the Potter units GSU when the units are not on-line, to reduce power flows through the Braintree loop and on NSTAR line 478-509 between Grove Street Substation and Holbrook. (BELD-02-T02) c) Installation of a second high-speed protection group, on BELD cable 115-9-4 between Grove Street and Plain Street Substations in Braintree, Massachusetts with the high-speed protection groups at both the Grove Street and Plain Street Substation being independent in accordance with NPCC criteria, to eliminate area stability concerns. (BELD-02-X01)

SCHEDULE 12C

Determination of Localized Costs On and After January 1, 2004

Introduction

The purpose of this Schedule 12C is to describe procedures that the System Operator will use in determining Localized Costs for RBUs and RTEP02 Upgrades on or after January 1, 2004.

Review and Approval

These Schedule 12C review and approval procedures are separate and distinct from any other approval procedures within the Agreement and are not a condition for receiving approval under any other section of the Agreement. If submission of a proposed plan for a Transmission Upgrade by a Participant for review pursuant to Section 18.4 of the Agreement (or the equivalent of such section as may be adopted under successor documents governing the regional transmission system in New England) is required, then the approval for Transmission Upgrade cost allocations as described under this Schedule 12C of the Tariff cannot occur sooner than after that review has been completed and it has been determined, pursuant to Section 18.4 of the Agreement (or the equivalent of such section as may be adopted under successor documents governing the regional transmission system in New England) that the Participant is free to proceed with implementation of the proposed Transmission Upgrade.

Entities conducting transmission system studies shall review and discuss transmission design and construction alternatives as they are developed under a System Impact Study ("SIS") or as part of the NEPOOL Transmission Plan with the System Operator, Reliability Committee and the Transmission Expansion Advisory Committee, as deemed appropriate by the System Operator.

1. Review Procedures For Determining Localized Costs

Every RBU and RTEP02 Upgrade shall be reviewed by the System Operator with advisory input from the Reliability Committee to determine if any of the costs associated with such upgrade are Localized Costs, except that a proposed Transmission Upgrade which costs less than $500,000 may be exempted from this review by the System Operator. The System Operator, with advisory input from the Reliability Committee, will review and update, as appropriate, the $500,000 threshold on an annual basis.

The Participant seeking cost recovery for a proposed Transmission Upgrade, including reconstruction or replacement, shall submit to the System Operator and the Reliability Committee the following information as deemed appropriate by the System Operator:

(a) A description of (i) the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered, and (ii) the most currently available study grade or better estimates of the construction, including the potential impact on the bulk power system during the construction of such upgrade, and (iii) the operating costs of the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered.

(b) A summary of the technical analysis performed for the Transmission Upgrade and the identified transmission alternatives.

(c) A review and discussion of the need for the proposed Transmission Upgrade.

(d) A discussion of why the requested Transmission Upgrade was selected over other transmission alternatives, with a description of the benefits of the proposed Transmission Upgrade over other transmission alternatives from an operational, timing of implementation, cost and reliability perspective.

If in reviewing the application and associated information, the System Operator, with advisory input from the Reliability Committee, decides that additional information, review, or study is required prior to acting on the application, the System Operator, with advisory input from the Reliability Committee, may elect to defer action and solicit supplementary information, review, or study as required. Sources for such additional information may be, but are not limited to, the entity sponsoring the application, Transmission Owners, and the Reliability Committee.

The System Operator shall determine what those reasonable requirements are that are 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 System Operator will consider, in accordance with Schedule 12C of this Tariff, the reasonableness of the proposed design and construction method with respect to (i) Good Utility Practice, (ii) the current engineering design and construction practices in the area in which the Transmission Upgrade is built, (iii) alternate feasible and practical Transmission Upgrades and (iv) the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrades. The costs of Transmission Upgrades that exceed those reasonable requirements, as determined above, shall be deemed Localized Costs. Local siting requirements for transmission facilities shall not be dispositive of whether or not Localized Costs exist with respect to any particular Transmission Upgrade.

The System Operator is authorized to develop detailed procedures to fulfill the objectives and requirements of this Schedule 12C.

2. Additional Transmission Upgrade Costs or Design Changes Subsequent to the System Operator's Determination of Localized Costs

If the costs associated with a Transmission Upgrade exceed the estimated Pool-Supported PTF costs determined in the original Localized Costs review by ten percent, or the design associated with the construction of a Transmission Upgrade is materially changed subsequent to the System Operator's determination of Localized Costs, then the applicant for Pool-Supported PTF costs shall be required to submit its Transmission Upgrade again to a review by the System Operator to determine if any of the incremental costs or costs associated with the change in design are Localized Costs.

3. Dispute Resolution Regarding Determination of Localized Costs

The System Operator's determination of Localized Costs under the Tariff shall take effect on the date on which the System Operator issues its written findings and determination. The applicant for cost recovery (the "Applicant") whose project is deemed to include Localized Costs may dispute such decision by the System Operator by submitting within 60 days of such decision formal written notice of the dispute to the System Operator, describing in detail the basis for its challenge of the System Operator's determination. The Applicant and the System Operator shall then enter into good faith negotiations for a period not to exceed 60 days from the date of the Applicant's written notice to try to resolve the dispute.

If there is no satisfactory resolution of the dispute at the end of the negotiation period, the Applicant shall then have the right to file a Section 206 complaint with the Commission.

APPENDIX A

RULES FOR DETERMINING INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

Effective June 1, 1998

* The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the NEPOOL Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section 15.1 of the Agreement (or the equivalent of such Section 15.1 as may be adopted under successor documents governing the regional transmission system in New England) shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in Sections 15.1 or 15.1A of the Agreement (or the equivalent of such definition as may be adopted under successor documents governing the regional transmission system in New England), shall remain classified as PTF for all purposes under the Agreement and this Tariff.

ATTACHMENT 5

TRANSMISSION COST CAUSATION WORKSHOP NO. 4

March 14, 2003

LastName	FirstName	Company
Atkins	Tom	Pinpoint Power
Barton	Lisa	Northeast Utilities
Bergeron	Denis	Maine Public Utilities Commission
Brown	Jim	Green Mountain Power Corp.
Bursaw	Chris	PG&E NEG
Carrigan	Kathleen	ISO New England Inc.
Chandley	John	LECG ?
Chattopadhyay	Pradip	New Hampshire Public Utilities Commission
Cope-Flanagan	John	MA Dept. of Telecommunications & Energy
D'Andrea	James	KeySpan-Ravenswood LLC
DaSilva	Fernando	FPL Energy
Doot	David	Day, Berry & Howard LLP
Dworkin	Michael	Vermont Public Service Board
Elder	John	Levitan & Associates, Inc.
Evans-Mongeon (Phone)	Brian	VT Public Power Supply Authority
Fink	Lisa	ME PUC
Folta	Peter	NSTAR
Fowler	Bill	Exelon
Gagliardi	Bob	The United Illuminating Company
Gallicchio	Michelle	Northeast Utilities
Goldberg	Matt	ISO New England Inc.
Goldschmidt	Stephen	Consultant for United Illuminating
Guerrette	Marc	Central Maine Power
Harnick	Nancy	Connecticut Office of Consumer Counsel
Hartley	Doug	RI PUC
Hinners	Richard	Vermont Electric Power Company
Ignatius	Amy	NECPUC
Johnson	Eric	ISO New England Inc.
Kassakian	John	ISO New England Board Member
Kathan	David	FERC
Kellner	Rick	Northeast Utilities
Klevorick	Alvin	ISO New England Board Member
Krawczyk	Paul	NSTAR
LeComte	Ron	MA DTE
Levitan	Richard	Levitan & Associates, Inc.
Manning	Deirdre	MA Dept. of Telecommunications & Energy
McCarren	Louise	ISO New England Board Member
McKinnon	Bill	Northeast Utilities
O'Connor	Carolyn	ISO New England Inc.
Parekh	Shashi	MA DTE
Pysh (Phone)	Rose	The United Illuminating Company
Renaud	Paul	Natinal Grid
Renner	Sheila	MA DTE
Rosen	Richard	Tellus Institute - representing the RI AG
Ross	Anne	NH Office of Consumer Advocate
Runge	Eric	Day, Berry & Howard LLP
Shapiro	Boris	MA DTE
Spring	Jerry	VELCO
Sussler	Philip	CMEEC
Taddeo (Phone)	Gene	Northeast Utilities
van Welie	Gordon	ISO New England Inc.

TRANSMISSION COST CAUSATION WORKSHOP NO. 4

March 14, 2003

LastName	FirstName	Company
Villar	Juan	FPL Energy
Wertheimer (Phone)	Mike	CT AG
Whitley	Steve	ISO New England Inc.

TRANSMISSION COST CAUSATION WORKSHOP NO. 3

January 17, 2003

LastName	FirstName	Company
Atkins	Tom	Pinpoint Power
Barton	Lisa	Northeast Utilities
Bessette	Thomas	TransEnergie US LTD
Burke	Richard	ISO-NE
Chattopadhyay	Pradip	New Hampshire PUC
Colca	Mark	Bangor Hydro-Electric Company
Coughlin	Robert	ISO-NE
DaSilva	Fernando	FPL Energy
Dunn	Tom	VELCO
Elder	John	Levitan
Forshaw	Brian	CMEEC
Fowler	Bill	Exelon
Fuller	Peter	Mirant Americas
Gagliardi	Bob	United Illuminating
Gallicchio	Michelle	Northeast Utilities
Gawronski	Jim	United Illuminating Co.
Goldberg	Matt	ISO-NE
Goldschmidt	Stephen	Consultant for United Illuminating
Guerrette	Marc	Central Maine Power
Harnick	Nancy	Connecticut Office of Consumer Counsel
Harris	Peter	ISO-NE
Hartley	Doug	Rhode Island Public Utilities Commission
Hashem	Julie	Maine State Planning Office
Hinners	Richard	Vermont Electric Power Company
Ignatius	Amy	NECPUC
Johnson	Eric	ISO-NE
Kaslow	Tom	Calpine
Kassakian	John	ISO-NE Board Member
Kellner	Rick	Northeast Utilities
Krawczyk	Paul	NSTAR Electric & Gas Corp.
LeComte	ron	MA DTE
Levitan	Richard	Levitan
Lockhart	Linda	Maine Public Advocate's Office
Mallory	Scott	VELCO
Mc KINNON	BRUCE	M.M.W.E.C.
McCarren	Louise	ISO-NE Board Member
McKinnon	William	Northeast Utilities
MENDRALA	CHERYL	TSO ISO-NE
Mertens	Hans	VT DPS
Nolan	Ken	Burlington Electric Department
O'Connor	Carolyn	ISO-NE
PAREKH	SHASHI	MA DTE
parker	seth	levitan & associates, inc.
Patton	David	Independent Market Advisor
Peterson	Paul	Synapse Energy Economics
Pysh	Rose	United Illuminating
Quinlan	Mark	CT DPUC
Renner	Sheila	MA DTE
Rogan	Peter	ISO NE
Rosen	Richard	Tellus Institute - representing the RI AG
Ruell	Cheryl	ISO-NE

TRANSMISSION COST CAUSATION WORKSHOP NO. 3
January 17, 2003

Runge	Eric	Day, Berry & Howard LLP
Shapiro	Boris	Mass DTE
Spring	Gerald	VELCO
Stein	Bob	Signal Hill for HQUS
Sussler	Philip	CMEEC
TADDEO	GENE	NORTHEAST UTILITIES
Tomasko	Jerry	Westfield Gas and Electric
van Welie	Gordon	ISO-NE
Waldstein	Sandra	Vermont Public Service Board
Welch	Thomas	Maine Public Utilities Commission
Whitley	Steve	ISO-NE

TRANSMISSION COST CAUSATION WORKSHOP NO. 2
December 11, 2002

LastName	FirstName	Company
Bentley	Bruce	Central Vermont Public Service Corp
Bergeron	Denis	Maine PUC
Brown	Jim	Green Mountain Power
Chattopadhyay	Pradip	New Hampshire Public Utilities Commission
Clarke	Robert	NSTAR
Coleman	Mary	New Hampshire Public Utilities Commission
DaSilva	Fernando	FPL Energy
Deehan	William	Central Vermont Public Service
Donahue	Kevin	Northstar Industries
Elder	John	Levitan & Associates
Elder	Jack	Levitan & Associates
Forshaw	Bran	CMEEC
Fowler	Bill	Exelon PowerTeam
Frantz	Thomas	New Hampshire Public Utilites Commission
Gagliardi	Bob	United Illuminating
Gallicchio	Michelle	Northeast Utilities
Gawronski	Jim	United Illuminating Co.
Goldberg	Matthew	ISO New England
Goldschmidt	Stephen	Consultant for United Illuminating
Gopinathan	Murale	Northeast Utilities
Guerrette	Marc	Energy East
Harnick	Nancy	CT Office of Consumer Counsel
Hashem	Julie	Maine Governor’s Office
Hinners	Richard	VELCO
Johnson	Eric	ISO-NE
Kaslow	Tom	Calpine
Kassakian	John	ISO-NE Board Member
Kellner	Rick	Northeast Utilities
Kokoszka	Chet	New Hampshire Public Utilities Commission
Krawczyk	Paul	NSTAR
LeComte	ron	MA DTE
Levitan	Richard	Levitan & Associates
Liepe	Paul	ISO-NE
Manning	Deirdre	MA DTE Commissioner
McCarren	Louise	ISO-NE Board Member
McKinnon	Bill	NU
McPherson	John	FERC
Mead	David	FERC
Mertens	Hans	VT DPS
Nolan	Kenneth	Burlington Electric Department
O'Connor	Carolyn	ISO-NE
PAREKH	SHASHI	MA DTE
Peterson	Paul	Synapse Energy Economics
Renner	Sheila	DTE
Rosen	Richard	Tellus Institute - representing the RI AG
Runge	Eric	Day, Berry & Howard LLP
Shapiro	Boris	MDTE
Sharpe Hayes	Mary	ISO-NE Board Member
sjoberg	charles	AES Londonderry
Smith	Hariph	Energy East/Central Maine Power
Smith	Philip	PG&E NEG
Spring	Jerry	VELCO
Stein	Robert	Signal Hill/HQUS
Sussler	Philip	CMEEC
Wertheimer	Michael	CT Attorney General's Office
Whitley	Stephen	ISO-NE

TRANSMISSION COST CAUSATION WORKSHOP NO. 1

November 15, 2002

LastName	FirstName	Company
Bentley	Bruce	Central Vermont Public Service Corp.
Bigelow	Robert	
Burke	Richard	ISO New England Inc.
Colca	Mark	Bangor Hydro-Electric Company
Crifo	Hope	Vermont Public Service Board
Deehan	William	Central Vermont Public Service Corp.
Downes	Donald	CT DPUC
Dunn	Tom	VELCO
Elder	Jack	Levitan & Associates
Foley	Ellen	ISO New England Inc.
Forshaw	Brian	CMEEC
Fowler	Bill	Exelon Power Team
Frantz	Tom	
Gagliardi	Bob	The United Illuminating Company
Gallicchio	Michelle	Northeast Utilities
Gawronski	Jim	The United Illuminating Company
Gentile	Thomas	National Grid USA
Goldberg	Matthew	ISO New England Inc.
Goldschmidt	Stephen	Consultant for The United Illuminating Company
Guerrette	Marc	Central Maine Power
Harnick	Nancy	CT Office of Consumer Counsel
Hinners	Richard	VELCO
Ignatius	Amy	NECPUC
Jasinski	John	Dept. of Public Utility Control-CT
Johnson	Eric	ISO New England Inc.
Kellner	Rick	Northeast Utilities
Krawczyk	Paul	NSTAR
LeComte	Ron	MA DTE
Levitan	Richard	Levitan & Associates, Inc.
Liepe	Paul	ISO New England Inc.
Lockhart	Linda	Maine Public Advocate's Office
Manning	Deirdre	MA DTE
McBrien	Joanne	MA Division of Energy Resources
McKinnon	William	Northeast Utilities
Mertens	Hans	VT DPS
Miller	Linda	ISO New England Inc.
Nolan	Ken	Burlington Electric Department
O'Connor	Carolyn	ISO New England Inc.
Paravalos	Mary Ellen	National Grid USA
Parekh	Shashi	MA DTE
Parker	Gary	VELCO
Peterson	Paul	Synapse Energy Economics
Pysh	Rose	The United Illuminating Company
Quinlan	Mark	CT DPUC
Renner	Sheila	MA DTE
Richards	Patty	Burlington Electric Department
Runge	Eric	Day, Berry & Howard LLP
Scarfone	Allen	Northeast Utilities
Scholten	Scott	Vermont Gas Systems
Shapiro	Boris	MA DTE
Sharp Hayes	Mary	ISO New England Board of Directors

TRANSMISSION COST CAUSATION WORKSHOP NO. 1

November 15, 2002

LastName	FirstName	Company
Sjoberg	Charles	AES Londonderry
Smith	Philip	PG&E NEG
Stein	Robert	Signal Hill for HQUS
Sussler	Philip	CMEEC
Tobian	Carol	TransEnergie US Ltd.
van Welie	Gordon	ISO New England Inc.
Vasington	Paul	MA DTE
Waldstein	Sandra	Vermont Public Service Board
Wertheimer	Michael	CT Attorney General's Office
Whitley	Steve	ISO New England Inc.

ATTACHMENT 6

Straw Proposals for Default Transmission Cost Allocation Mechanisms

Prepared By: ISO-NE
Date: January 13, 2003

As indicated at the end of the second Stakeholder Workshop, ISO-NE has compiled the following cost causation straw proposals for default transmission cost allocation mechanisms. These proposals are for your consideration and for comment and discussion at the third Stakeholder Workshop.

The following table contains draft default cost allocation mechanisms to be considered for the types of transmission upgrades that would be considered "pool transmission facilities" ("PTF") identified and built pursuant to the regional transmission expansion planning process. The default cost allocation mechanism developed by the stakeholder working group is proposed to apply prospectively and not to projects identified in the Commission's December 20, 2002 Order. The mechanism would not apply to: Non-PTF, merchant transmission facilities, elective upgrades, and Generator Interconnection Related Upgrades (the costs of which are allocated pursuant to Schedule 11 of the NEPOOL Tariff)[1]

[1] ISO-NE notes that some stakeholders have recommended that least cost planning occur prior to allocating of costs of transmission upgrades, and that any "gold-plated" facilities (*e.g.*, redundant or underground facilities) called for by a local area be allocated only to that local area.

Method	Description
(A) Initial Study Identifies Benefits for Life of Project	1. Utilize RTEP study results (RTEP planning horizon) to determine the beneficiaries (local, regional, combination) and to determine cost allocation for life of the upgrade, after the upgrade has been identified in the RTEP[2]. a. LOLE analysis for each zone and for the system as a whole – __% weight b. Zonal Congestion analysis – __ % weight c. Transmission Reliability analysis – __% weight d. Competitive impact analysis – __% weight 2. If project is determined by LOLE analysis to be required for regional compliance with NPCC standards or to protect against system reliability falling out of compliance with such standards (under 1.a) or otherwise provide regional reliability benefits (under 1.c), project cost is regionalized for life of the project.
(B) Initial Study/Then Regionalize	1. Same as Method (A), but if project is not determined by LOLE analysis to be required for regional compliance with NPCC standards or to protect to protect against system reliability falling out of compliance with such standards (under 1.a) or otherwise provide regional reliability benefits (under 1.c), then the initial study under #1 above is used to determine who benefits and who pays for the duration of the period studied. For subsequent years, the costs of the project are regionalized to all transmission customers to account for the changes in utilization of the transmission facility due to the dynamic nature of future system operations.

[2] The ISO-NE Board may, however, in its discretion reassess the beneficiaries of the approved Upgrade as system conditions warrant.

(C) Tiered Voltage Approach	1. Costs of identified RTEP transmission projects are allocated in the following manner for the life of the facility if they provide for 2-way traffic. a. >=230kV 100% Regional 0% local zone b. >=115kV - <230kV 75% Regional 25% local zone c. >=69kV - <115kV 50% Regional 50% local zone d. <69kV 0% Regional 100% local zone 2. *Override Option* – If project is determined by LOLE analysis to be required for regional compliance with NPCC standards or to protect against system reliability falling out of compliance with such standards (under 1.a) or otherwise provide regional reliability benefits (under 1.c), project cost is regionalized for life of the project.
(D) Regionalize PTF	1. Costs of identified RTEP transmission projects are regionalized for life of the project at 69kV and above if they are classified as PTF a. Project voltages are 69kV and above b. Provides for 2-way traffic (non-radial)

ATTACHMENT 7

NEPOOL PARTICIPANTS COMMITTEE
100TH AGREEMENT VOTE TALLIES
JUNE 25, 2003

SECTOR	Vote to Amend	Vote to Ballot	Balloting Results
GENERATION	15.00	15.00	13.33
TRANSMISSION	14.29	17.14	16.67
SUPPLIER	11.43	7.50	10.00
PUBLICLY OWNED ENTITY	20.00	20.00	19.38
END USER	16.00	16.00	18.46
% IN FAVOR	**76.71**	**73.93**	**77.84**

GENERATION SECTOR

Participant Name	Vote to Amend	Vote to Ballot	Balloting Results
ANP Marketing	F	F	F
Duke Energy North America	A	A	
Entergy Nuclear Generation Company		A	A
FPL Energy LLC	F	F	F
Generation Group Member	O	O	A
Mirant New England, LLC	A	A	O
TransCanada Power Marketing	F	F	
IN FAVOR (F)	3	3	2
OPPOSED (O)	1	1	1
TOTAL VOTES	4	4	3
ABSTENTIONS (A)	2	3	2

TRANSMISSION SECTOR

Participant Name	Vote to Amend	Vote to Ballot	Balloting Results
Bangor Hydro-Electric Co.	O	F	
Boston Edison Company	F	F	F
Central Maine Power Company	O	O	O
New England Power Company	F	F	F
Northeast Utilities System Co.s	F	F	F
The United Illuminating Co.	F	F	F
Vermont Electric Power Co.	F	F	F
IN FAVOR (F)	5	6	5
OPPOSED (O)	2	1	1
TOTAL VOTES	7	7	6
ABSTENTIONS (A)	0	0	0

NEPOOL PARTICIPANTS COMMITTEE
100TH AGREEMENT VOTE TALLIES
JUNE 25, 2003

SUPPLIER SECTOR

Participant Name	Vote to Amend	Vote to Ballot	Balloting Results
AES Londonderry	A	A	
Aquila Merchant Services		A	
Calpine Energy Services, L.P.	F	A	O
Consolidated Edison Energy, Inc.	A	A	
Constellation Power Source, Inc.	F	F	F
Demand Response Providers	O	O	
El Paso Merchant Energy, LP	A	A	A
Exelon Generation Company, LLC	O	O	O
H.Q. Energy Services (U.S.) Inc.	A	F	
Indeck-Pepperell Power Associates, Inc	A	A	F
LIPA	A	A	F
NRG Power Marketing, Inc.	O	O	O
PG&E Energy Trading	A	A	A
PPL EnergyPlus, LLC	F	O	
PSEG Energy Resources & Trade LLC	A	O	O
Rainbow Energy Marketing, Inc.			A
Sempra Energy Trading Corp.	A	A	
TXU Portfolio Management Co. LP			A
Virginia Electric and Power Company	F	F	F
IN FAVOR (F)	4	3	4
OPPOSED (O)	3	5	4
TOTAL VOTES	7	8	8
ABSTENTIONS (A)	9	9	4

END USER SECTOR

Participant Name	Vote to Amend	Vote to Ballot	Balloting Results
Associated Industries of Massachusetts	A	F	F
Connecticut Office of Consumer Counsel	F	F	F
Forster, Inc.	A	A	F
Gardiner Paperboard	A	A	F
Industrial Energy Consumer Group	A	A	F
Maine Skiing, Inc.	A	A	F
Maine, State of, Office of the Governor	O	O	O
Mead Oxford Corporation	A	A	F
New Hampshire Office of Consumer Advocate	A	A	
PowerOptions, Inc.	F	F	F
Praxair, Inc. (L)			F
Silkman, Richard	A	O	
Texas Instruments	F	F	F
The Energy Consortium	F	F	F
The Energy Council of Rhode Island	A	A	F
Union of Concerned Scientists	A	A	
IN FAVOR (F)	4	5	12
OPPOSED (O)	1	2	1
TOTAL VOTES	5	7	13
ABSTENTIONS (A)	10	8	0

NEPOOL PARTICIPANTS COMMITTEE
100TH AGREEMENT VOTE TALLIES
JUNE 25, 2003

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote to Amend	Vote to Ballot	Balloting Results
Ashburnham Municipal Light Plant	F	F	F
Belmont Municipal Light Department	F	F	F
Boylston Municipal Light Department	F	F	F
Braintree Electric Light Department	F	F	F
Chicopee Municipal Lighting Plant	F	F	F
Concord Municipal Light Plant	F	F	F
Conn. Municipal Electric Energy Coop.	F	F	
Danvers Electric Division	F	F	F
Georgetown Municipal Light Dept.	F	F	F
Groton Electric Light Department	F	F	F
Hingham Municipal Lighting Plant	F	F	F
Holden Municipal Light Department	F	F	F
Holyoke Gas & Electric Department	F	F	
Hudson Light and Power Department	F	F	F
Hull Municipal Lighting Plant	F	F	F
Ipswich Municipal Light Department	F	F	F
Littleton Electric Light Department	F	F	
Mansfield Municipal Electric Department	F	F	F
Marblehead Municipal Light Department	F	F	F
Mass. Municipal Wholesale Electric Co.	F	F	F
Middleborough Gas and Electric Dept.	F	F	F
Middleton Municipal Electric Dept.	F	F	F
North Attleborough Electric Department	F	F	F
Pascoag Utility District	F	F	F
Paxton Municipal Light Department	F	F	F
Peabody Municipal Light Plant	F	F	F
Rowley Municipal Lighting Plant	F	F	F
Shrewsbury's Electric Light Plant	F	F	F
South Hadley Electric Light Department	F	F	F
Sterling Municipal Electric Light Dept.	F	F	F
Taunton Municipal Lighting Plant	F	F	
Templeton Municipal Lighting Plant	F	F	F
Vermont Public Power Supply Authority	F	F	F
Wakefield Municipal Gas and Light	F	F	F
West Boylston Municipal Lighting Plant	F	F	F
Westfield Gas & Electric Light Dept.	F	F	O
IN FAVOR (F)	36	36	31
OPPOSED (O)	0	0	1
TOTAL VOTES	36	36	32
ABSTENTIONS (A)	0	0	0

ATTACHMENT 8

SETTLEMENT PROPOSAL

Cost Allocation for New PTF Transmission Investment In New England

1. All PTF[1] projects that have been approved by the RTEP and provide for 2-way traffic with a total cost below $10 million dollars[2] will be rolled-in regionally for the life of facilities.

2. All PTF projects with a total cost of $10 million dollars or more, that have been approved by RTEP/regional plan and provide for 2-way traffic, will have fifty percent of the project costs allocated regionally and fifty percent allocated to the local zone(s) that are the primary beneficiaries of the proposal for the life of the facility.[3]

3. Primary beneficiaries are determined with reference to the RTEP. If the RTEP identifies a project as being necessary to address local economic or reliability problems, the zone or zones which contain the local economic or reliability problem identified in the RTEP are the primary beneficiaries. For example, if the purpose of a project is primarily to reduce congestion costs or fix a reliability problem within a zone or zones or within a load pocket within a zone, the zone or zones identified in the RTEP in which congestion costs will be reduced or reliability will be improved as a result of the project are the primary beneficiaries of the project.

4. The cost of a project will be rolled in regionally only if the RTEP does not identify any primary beneficiary or beneficiaries.

5. For any project to which this cost allocation methodology applies, the ISO or RTO may reopen at five year intervals the determination of cost allocation if there have been significant changes in the primary beneficiaries of the project. Changes in the cost allocation will be prospective only.

6. This cost allocation methodology applies to upgrades not under construction as of the implementation of LMP in New England on March 1, 2003, including all of the projects included in RTEP02.

---

1 PTF refers to Pool Transmission Facilities as defined in the current NEPOOL Agreement section 15.1.

2 Segmenting a project into smaller projects that cost less than $10 million dollar is prohibited.

3 Zones are defined as reliability zones in the tariff. If they change, the previous allocation will not change.

7. The incremental cost of underground lines that could otherwise be installed as overhead lines would be allocated to the zone requiring the burial. However, if population density, technical infeasibility, or sound engineering practice requires underground installation, the cost will be allocated in accordance with the percentages set forth in paragraph 2, above.

8. The cost of merchant transmission will be paid for by bilateral agreement.

9. This proposal does not address generator interconnection.

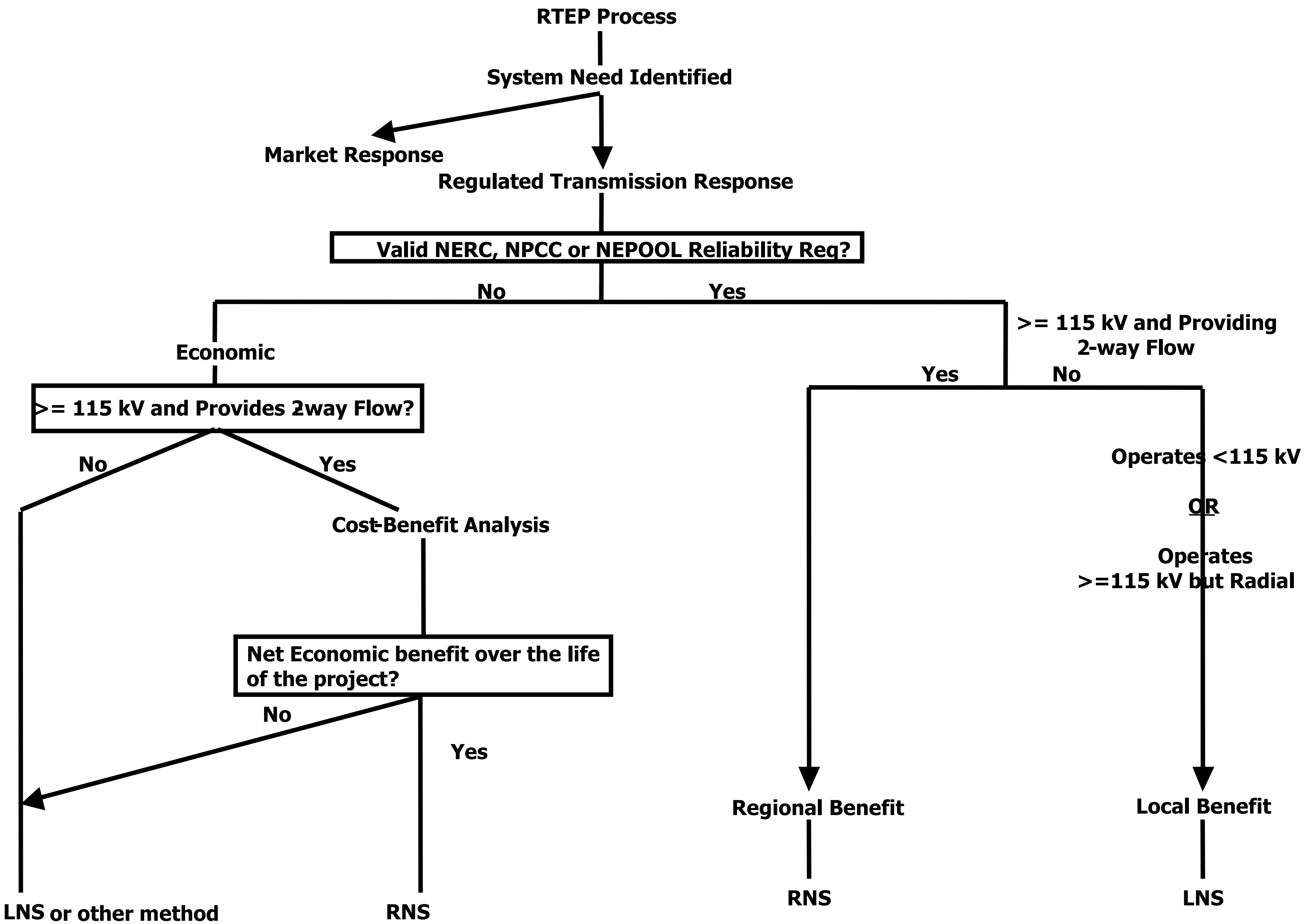
10. The cost of a new PTF project needed for the benefit of another RTO (ISO) will be paid for by those customers requesting it or by the other RTO (ISO). The cost of a new PTF project that is needed for the benefit of more than one RTO will be paid for in accordance with the benefits received by each RTO or through mutual agreement. Other “gold plated” upgrades would also be treated as elective upgrades and supported by the requester. The planning process must take into account the needs identified by the Resource Adequacy requirements and NEPOOL Reliability Standard requirements.

11. Any zone that is transmission export constrained will be exempt from paying a share of any project, the purpose of which is to eliminate the export constraint, provided that such exemption may be prospectively rescinded if the zone is subsequently determined to be a primary beneficiary under paragraph 5.

12 This PTF cost allocation must be in place for at least 10 years to ensure generational and geographic equity.

ATTACHMENT 9

Transmission Project Assessment & Cost Allocation Process



ATTACHMENT 10

Charles Sjoberg
AES Londonderry
c/o AES Odyssey
1001 West Seneca Street
Suite 100
Ithaca, NY 14850

Chris Wentlent (Alt)
AES Londonderry
c/o AES Westover
720 Riverside Drive
Johnson City, NY 13790

Carl Peterson
AIG Energy, Inc.
One Greenwich Plaza
Greenwich, CT 06830

Hilary Garfein (Alt)
AIG Energy, Inc.
One Greenwich Plaza
Greenwich, CT 06830

Ron McNamara
American Electric Power Service Corporation
One Riverside Plaza
14th Floor
Columbus, OH 43215

Thomas Chapman (Alt)
American Electric Power Service Corporation
One Riverside Plaza
14th Floor
Columbus, OH 43215

Dorothy J. Capra
Director Regulatory Affairs
ANP Marketing Company
62 Forest Street, Suite 102
Marlborough, MA 01752

William Henson (Alt)
Director, Power Marketing
ANP Marketing Company
62 Forest Street, Sutie 102
Marlborough, MA 01752

Kevin J. Fox
Portfolio Manager & Vice President
Aquila Merchant Services, Inc.
1100 Walnut, Suite 3300
Kansas City, MO 64106

Peter W. Brown (Alt)
Attorney
Aquila Merchant Services, Inc.
c/o Brown, Olson & Wilson, P.C.
501 South Street
Concord, NH 03304

Stanley W. Herriott
Manager
Ashburnham Municipal Light Plant
78 Central Street
P.O. Box 823
Ashburnham, MA 01430

Roger W. Bacon (Alt)
Ashburnham Municipal Light Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Robert Ruddock
Executive Vice President
Associated Industries of Massachusetts
Suite 1300
222 Berkeley Street
Boston, MA 02117

Angela M. O'Connor (Alt)
Vice President of Energy Programs
Associated Industries of Massachusetts
13th Floor
222 Berkeley Street
Boston, MA 02117

Jeffrey A. Jones
Manager-Legal & Regulatory Services
Bangor Hydro-Electric Company
33 State Street
P.O. Box 932
Bangor, ME 04402-0932

Gregory Hines (Alt)
Director of Business Services
Bangor Hydro-Electric Company
33 State Street
P.O. Box 932
Bangor, ME 04402-0932

Timothy L. McCarthy
Manager
Belmont Municipal Light Department
450 Concord Avenue
Belmont, MA 02478

Roger W. Bacon (Alt)
Belmont Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Ellen K. Angley
Vice President, Energy Supply and Transmission
Boston Edison Company
c/o NSTAR
800 Boylston Street, P1603
Boston, MA 02199-8001

Robert P. Clarke (Alt)
Director, Energy Planning and Supply
Boston Edison Company
c/o NSTAR
800 Boylston Street (P1704)
Boston, MA 02199-8001

H. Bradford White, Jr.
Manager
Boylston Municipal Light Department
Paul X. Tivnan Road
P.O. Box 753
Boylston, MA 01505-0753

Roger W. Bacon (Alt)
Boylston Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Robert Scavone
BP Energy Company
501 WestLake Park Boulevard
Houston, TX 77079

Jason Stever (Alt)
BP Energy Company
501 WestLake Park Boulevard
Houston, TX 77079

Laurie J. Heffron
Electric Operations Manager
Braintree Electric Light Department
150 Potter Road
Braintree, MA 02184-3598

John P. Coyle (Alt)
Braintree Electric Light Department
c/o Duncan & Allen
1575 Eye Street, NW
Washington, DC 20005-1175

Paul Jutras
Brascan Energy Marketing, Inc.
2 Montreal Road West
Masson-Angers, Quebec, CANADA J8M 1K6

Richard St. Jean (Alt)
Brascan Energy Marketing, Inc.
2 Montreal Road West
Masson-Angers, Quebec, CANADA J8M 1K6

Thomas Kaslow
Calpine Energy Services, LP
c/o Calpine Eastern Corporation
The Pilot House, 2nd Floor
Lewis Wharf
Boston, MA 02110

Jeff Woodall (Alt)
Lead Scheduler
Calpine Energy Services, LP
700 Louisiana Ave., Ste. 2700
Houston, TX 77002

Margaret Downey
Asst. County Administrator
Cape Light Compact, The
3195 Main Street
P.O. Box 427
Barnstable, MA 02630

Robert Bigelow (Alt)
Cape Light Compact, The
P.O. Box 165
Woods Hole, MA 02543

John Trimble
Business Development Manager
Cargill Power Markets, LLC
12700 Whitewater Drive
Minnetonka, MN 55343-9439

Gaston Garrido (Alt)
Trading Manager
Cargill Power Markets, LLC
12700 Whitewater Drive
Minnetonka, MN 55343-9439

Eric N. Stinneford
Manager, Power Contracts Administration
Central Maine Power Company
41 Anthony Avenue
Augusta, ME 04330

Hariph M. Smith (Alt)
Central Maine Power Company
41 Anthony Avenue
Augusta, ME 04330

Jeffrey R. Cady
Power Resource Manager
Chicopee Municipal Lighting Plant
725 Front Street
P.O. Box 405
Chicopee, MA 01021-0405

Brian Forshaw
Chicopee Municipal Lighting Plant
c/o Connecticut Municipal Electric Energy
Cooperative
30 Stott Avenue
Norwich, CT 06360-1535

Jason Barker
The Cincinnati Gas & Electric Company, Inc.
139 East 4th Street
EA503
Cincinnati, OH 45202

Walt Yaeger (Alt)
The Cincinnati Gas & Electric Company, Inc.
139 East 4th Street
EA503
Cincinnati, OH 45202

Murat Alptekin
Director
Citadel Energy Products LLC
c/o Citadel Investment Group, LLC
225 W. Washington St., 9th Fl.
Chicago, IL 60606

Peter Sullivan (Alt)
Vice President
Citadel Energy Products LLC
c/o Citadel Investment Group, LLC
225 W. Washington St., 9th Fl.
Chicago, IL 60606

Daniel J. Sack
Superintendent
Concord Municipal Light Plant
1175 Elm Street
P.O. Box 1029
Concord, MA 01742-1029

Roger W. Bacon (Alt)
Concord Municipal Light Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Marj Garbini
Transmission Engineer
Conectiv Energy Supply, Inc.
P.O. Box 6066
Newark, DE 19714-6066

Bill Fehr (Alt)
Power Trading Manager
Conectiv Energy Supply, Inc.
P.O. Box 6066
Newark, DE 19714-6066

Brian E. Forshaw
Director
Connecticut Municipal Electric Energy Cooperative
30 Stott Avenue
Norwich, CT 06360-1535

Maurice R. Scully (Alt)
Executive Director
Connecticut Municipal Electric Energy Cooperative
30 Stott Avenue
Norwich, CT 06360-1535

Kenneth Bekman
Director, Wholesale Power
Consolidated Edison Energy, Inc.
701 Westchester Avenue
Suite 320E
White Plains, NY 10604

Michael Forte (Alt)
General Manager
Consolidated Edison Energy, Inc.
4 Irving Place, Room 1349S
New York, NY 10003

Carrie Cullen-Hitt (Alt)
Constellation Power Source, Inc.
111 Market Place
Suite 500
Baltimore, MD 21202

Daniel W. Allegretti
Constellation Power Source, Inc.
One Essex Drive
Bow, NH 03304

Matthew Picardi
Coral Power, LLC
General Manager – Regulatory Affairs
27 Winthrop Rd.
Hingham, MA 02043

Robert Reilley (Alt)
Vice President-Regulatory Affairs
Coral Power, LLC
909 Fannin Street
Suite 700
Houston, TX 77010

Coleen O'Brien-Pitts
Electric Utility Director
Danvers Electric Division
One Burroughs Street
Danvers, MA 01923-2702

Francis M. Gaffney (Alt)
Power Supply Engineer
Danvers Electric Division
One Burroughs Street
Danvers, MA 01923-2702

Dean L. Wilde, II
Managing Member
DC Energy, LLC
8065 Leesburg Pike; Suite 500
Vienna, VA 22182

Ware Adams (Alt)
Vice President
DC Energy, LLC
8065 Leesburg Pike; Suite 500
Vienna, VA 22182

Thomas E. Atkins
President
DRP Group Member
c/o Pinpoint Power LLC
440 Commercial Street
Boston, MA 02109

Ken Roberts, Jr. (Alt)
DRP Group Member
c/o Pinpoint Power LLC
440 Commercial Street
Boston, MA 02109

Gregory Pakela
Manager of Operations
DTE Energy Trading, Inc.
101 N. Main Street
Suite 300
Ann Arbor, MI 48104

Alan Cherkas (Alt)
Originator
DTE Energy Trading, Inc.
414 South Main Street
Suite 200
Ann Arbor, MI 48104

Stacy L. Dimou
Duke Energy North America LLC
P.O. Box 426
Millinocket, ME 04462

George Johnson (Alt)
Attorney
Duke Energy North America LLC
c/o Dickstein, Shapiro, Morin & Oshinsky LLP
2101 L Street, N.W.
Washington, DC 20037-1526

Steve Vavrik
Director
Dynegy Power Marketing, Inc.
c/o Dynegy Marketing & Trade
1000 Louisiana Suite 5800
Houston, TX 77002

Miles Allen (Alt)
Sr. Vice President
Dynegy Power Marketing, Inc.
101 Merrimic Street, 2nd Floor
Boston, MA 02114

William Roberts
SVP Power Contracting
Edison Mission Marketing & Trading, Inc.
160 Federal Street
Boston, MA 02110-1776

Jeffry Ellis (Alt)
Edison Mission Marketing & Trading, Inc.
160 Federal Street
Boston, MA 02110-1776

Tim Cotner
El Paso Merchant Energy, LP
70 Walnut Street
Wellesley Hills, MA 02481

Robert Stein (Alt)
Principal Consultant
El Paso Merchant Energy, LP
c/o Signal Hill Consulting Group
128 Merchants Row
Suite 703
Rutland, VT 05701

Calvin P. Deschene
Director
Energy Atlantic, LLC
830 Main Street
Suite 20
P.O. Box 1148
Presque Isle, ME 04769-1148

Don Theriault (Alt)
Forecast Analyst
Energy Atlantic, LLC
P.O. Box 1148
Presque Isle, ME 04769-1148

Dennis J. Duffy
Energy Management, Inc.
One Energy Road
North Dartmouth, MA 02747

Chris Sherman (Alt)
Energy Management, Inc.
One Energy Road
North Dartmouth, MA 02747

Brent Dorsey
Entergy Nuclear Generation Company
P.O. Box 3200
Jackson, MS 39286

William Stone (Alt)
Entergy Nuclear Generation Company
600 Rocky Hill Road
Plymouth, MA 03260

Mike Roan
Exelon Generation Company, LLC
c/o Exelon New England Holdings, LLC
The Schrafft Center
529 Main Street
Suite 605
Charlestown, MA 02129

Jack Crowley (Alt)
Exelon Generation Company, LLC
c/o Exelon New England Holdings, LLC
The Schrafft Center
529 Main Street
Suite 605
Charlestown, MA 02129

Donald J. Sipe
Forster, Inc.
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Benjamin Bilus (Alt)
Forster, Inc.
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Roberto R. Denis
Vice President
FPL Energy LLC
9250 W. Flagler Street
Suite 5494
Miami, FL 33174

Fernando DaSilva (Alt)
Director, Market Affairs
FPL Energy LLC
8 Woodlawn Road
Assonet, MA 02702

Donald J. Sipe
Gardiner Paperboard
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Benjamin Bilus (Alt)
Gardiner Paperboard
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

William P. Short III
Generation Group Member
c/o Ridgewood Power Management, LLC
947 Linwood Avenue
Ridgewood, NJ 07450

Anthony M. Callendrello
Chief Operating Officer
Great Bay Power Marketing, Inc.
222 International Drive
Suite 125
Portsmouth, NH 03801-6819

William Rodgers (Alt)
Director of Marketing
Great Bay Power Marketing, Inc.
51 Dow Highway, Suite 7
Eliot, ME 03903

Wayne Snow
Manager
Georgetown Municipal Light Department
94 Searle Street
Georgetown, MA 01833

Roger W. Bacon (Alt)
Georgetown Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Doris Chojowski
Manager
Groton Electric Light Department
23 Station Avenue
Groton, MA 01450-4222

Roger W. Bacon (Alt)
Groton Electric Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Mark Hallenbeck
Hess Energy Power & Gas Company, LLC
1185 Avenue of the Americas
New York, NY 10036

Charles F. Cerria (Alt)
Hess Energy Power & Gas Company, LLC
1185 Avenue of the Americas
New York, NY 10036

Ariane Connor
H.Q. Energy Services (U.S.) Inc.
75, boul. Rene-Levesque Ouest
17e etage
Montreal, Quebec H2Z 1A4
CANADA

Robert Stein (Alt)
Principal Consultant
H.Q. Energy Services (U.S.) Inc.
c/o Signal Hill Consulting Group
128 Merchants Row
Suite 703
Rutland, VT 05701

Joseph R. Spadea Jr.
Manager
Hingham Municipal Lighting Plant
222 Central Street
Hingham, MA 02043-2518

Roger W. Bacon (Alt)
Hingham Municipal Lighting Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Roger W. Bacon (Alt)
Holden Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

James M. Lavelle
Manager
Holyoke Gas & Electric Department
99 Suffolk Street
Holyoke, MA 01040

Brian C. Beauregard (Alt)
Superintendent
Holyoke Gas & Electric Department
99 Suffold Street
Holyoke, MA 01040

Anthony J. Monteiro
General Manager
Hudson Light & Power Department
49 Forest Avenue
Hudson, MA 01749

Roger W. Bacon (Alt)
Hudson Light & Power Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

John A. MacLeod
Manager
Hull Municipal Lighting Plant
15 Edgewater Road
Hull, MA 02045-2714

Roger W. Bacon (Alt)
Hull Municipal Lighting Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Maurice T. Klefeker
Asset Manager
Indeck Pepperell Power Associates, Inc.
1075 Noel Avenue
Wheeling, IL 60090

Mark V. Magyar (Alt)
Consultant
Indeck Pepperell Power Associates, Inc.
c/o Financial Management Co.
325A Southbridge Street
Auburn, MA 01501

Donald J. Sipe
Industrial Energy Consumer Group
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Benjamin Bilus (Alt)
Industrial Energy Consumer Group
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Sandra Gillis
Business Manager
Industrial Power Services Corp.
Business Manager
60 East Street (rear)
Ware, MA 01082

James M. Malandrinos (Alt)
President
Industrial Power Services Corp.
Business Manager
60 East Street (rear)
Ware, MA 01082

Raymond R. Shockey
Manager
Ipswich Municipal Light Department
P.O. Box 151
272 High Street
Ipswich, MA 01938-0151

Roger W. Bacon (Alt)
Ipswich Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Gordon van Welie
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Kevin Kirby (Alt)
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Richard Ruzika
Managing Director
J. Aron & Company
85 Broad Street
New York, NY 10004

Thomas Hoatson (Alt)
Vice President
J. Aron & Company
c/o Goldman Sachs & Company
85 Broad Street
New York, NY 10004

Robert J. Gray
President
J.F. Gray & Associates LLC
35 Woodman Road
South Hampton, NH 03827

John F. Gray (Alt)
J.F. Gray & Associates LLC
35 Woodman Road
South Hampton, NH 03827

LaPorta, Leonard
150 West Newton Street
Boston, MA 02118

James Parmelee
Director of Power Markets
LIPA
31 Brinker Drive South
Rensselaer, NY 12144

William Killgoar (Alt)
LIPA
c/o Navigant Consulting Inc.
200 Wheeler Road
Burlington, MA 01803

Scott Edwards
Assistant General Manager
Littleton Electric Light & Water Department
39 Ayer Road
P.O. Box 2406
Littleton, MA 01460-3406

Roger W. Bacon (Alt)
Littleton Electric Light & Water Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Stephen M. Gauthier
Program Manager
Maine Health & Higher Educational
Facilities Authority
3 University Drive
P.O. Box 2268
Augusta, ME 04338-2268

Robert O. Lenna (Alt)
Executive Director
Maine Health & Higher Educational Facilities Authority
3 University Drive
P.O. Box 2268
Augusta, ME 04338-2268

Donald J. Sipe
Maine Skiing, Inc.
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Benjamin Bilus (Alt)
Maine Skiing, Inc.
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

John J. Beliveau
Director
Mansfield Electric Light Department
125 High Street, Suite 4
Mansfield, MA 02048-2404

Roger W. Bacon (Alt)
Mansfield Electric Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Robert V. Jolly Jr.
Manager
Marblehead Municipal Light Department
80 Commercial Street
P.O. Box 369
Marblehead, MA 01945-0369

Roger W. Bacon (Alt)
Marblehead Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

John J. McSweeney, Jr.
Director of Operations Support
Massachusetts Bay Transportation Authority
45 High Street
Boston, MA 02110

Mayhew Seavey (Alt)
Principal
Massachusetts Bay Transportation Authority
c/o PLM, Inc.
35 Main Street
Hopkinton, MA 01748

Roger W. Bacon
Director, Power Services Division
Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Timothy Peet (Alt)
Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Frank Gorke
Massachusetts Public Interest Research Group
29 Temple Place
5th Floor
Boston, MA 02111

Robert Sargent (Alt)
Massachusetts Public Interest Research Group
29 Temple Place
5th Floor
Boston, MA 02111

Donald J. Sipe
Mead Oxford Corporation
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Benjamin Bilus (Alt)
Mead Oxford Corporation
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

James L. Collins
Energy Analyst
Middleborough Gas & Electric
2 Vine Street
Middleborough, MA 02346

Roger W. Bacon (Alt)
Middleborough Gas & Electric
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Mark T. Kelly
Manager
Middleton Municipal Light Department
197 North Main Street
Middleton, MA 01949-1068

Roger W. Bacon (Alt)
Middleton Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Peter D. Fuller
Mirant New England, LLC
1099 Hingham Street
Rockland, MA 02370

Michael R. Kirkwood (Alt)
Mirant New England, LLC
1099 Hingham Street
Rockland, MA 02370

Levon Kazarian
Vice President
Morgan Stanley Capital Group Inc.
1585 Broadway
4th floor
New York, NY 10036

Doron Ezickson (Alt.)
Morgan Stanley Capital Group, Inc.
c/o McDermott, Will & Emery
28 State Street
Boston, MA 02109

Michael Hager
New England Power Company
25 Research Drive
Westborough, MA 01582

Mary Ellen Paravalos (Alt)
New England Power Company
25 Research Drive
Westborough, MA 01582

Fred C. Anderson
General Manager
New Hampshire Electric Cooperative, Inc.
579 Tenney Mountain Highway
Plymouth, NH 03264-3147

Stephen Kaminski (Alt)
Director, Energy Access & Services
New Hampshire Electric Cooperative, Inc.
579 Tenney Mountain Highway
Plymouth, NH 03264-3147

Michael W. Holmes
Consumer Advocate
New Hampshire Office of Consumer Advocate
117 Manchester Street
Concord, NH 03301

Paul Peterson (Alt)
New Hampshire Office of Consumer Advocate
c/o Synapse Energy Economics, Inc.
22 Pearl Street
Cambridge, MA 02139

Mark V. Magyar
North Attleborough Electric
c/o Financial Management Group
325A Southbridge Street
Auburn, MA 01501

Roger W. Bacon (Alt)
North Attleborough Electric
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Frank P. Sabatino
Senior Vice President - Power Marketing
Northeast Utilities System Companies
c/o Select Energy, Inc.
107 Selden Street
Berlin, CT 06037

James R. Shuckerow (Alt)
Director-Wholesale Power Contracts
Northeast Utilities System Companies
P.O. Box 270
Hartford, CT 06141-0270

Malcolm N. McDonald
Superintendent
Norwood Municipal Light Department
206 Central Street
Norwood, MA 02062-3567

Joseph DeVito
Regulatory Specialist
NRG Power Marketing Inc.
c/o NRG Energy
10 Southpond Circle
Cheshire, CT 06410

Elizabeth Wisniewski
Director of New England Regulatory Affairs
NRG Power Marketing Inc.
6 Barton Street
Newburyport, MA 01950

Hinwing Lee
President
Outback Power Marketing, Inc.
16225 Park Ten Place Drive Ste 500
Houston, TX 77084

Theodore G. Garill
General Manager
Pascoag Utility District
55 South Main Street
P.O. Box 107
Pascoag, RI 02859-0107

Roger W. Bacon (Alt)
Pascoag Utility District
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Diane Dillman
Manager
Paxton Municipal Light Department
578 Pleasant Street
Paxton, MA 01612-1365

Roger W. Bacon (Alt)
Paxton Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Ronald Tabroff
Supervisor, Electrical Engineer
Peabody Municipal Light Plant
201 Warren Street, Ext.
Peabody, MA 01960-4208

Roger W. Bacon (Alt)
Peabody Municipal Light Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Benson Caswell
President
PowerOptions, Inc.
99 Summer Street
Boston, MA 02110-1240

Douglas Stevenson (Alt)
PowerOptions, Inc.
Rte. 1, P.O. Box 398
Wayne, ME 04284

John F. Brodbeck
Energy Consultant
PPL EnergyPlus, LLC
2 North Ninth Street
Allentown, PA 18101-1179

Garrith W. Kirkner (Alt)
PPL EnergyPlus, LLC
2 North Ninth Street
Allentown, PA 18101-1179

Robert A. Weishaar, Jr.
Counsel
Praxair, Inc.
c/o McNees Wallace & Murick LLC
777 North Capitol Street, N.E.
Suite 401
Washington, DC 20002

Jennifer Hunsperger (Alt)
Account Manager, Eastern Region
Praxair, Inc.
126 Windham Drive
Langhorne, PA 10947

Debra M. Bateman
Providence Energy Services, Inc.
Mail Stop GENWT21
East Office
56 Exchange Terrace
Providence, RI 02903

James M. Stephens (Alt)
Providence Energy Services, Inc.
56 Exchange Terrace
Providence, RI 02903

Joel Gordon
Director, Market Policy
PSEG Energy Resources & Trade LLC
7 Steeple Lane
Amherst, NH 03031

Daniel P. Ciullo (Alt)
Marketing Manager – New England
PSEG Energy Resources & Trade LLC
80 Park Plaza – T19
Newark, NJ 07102-4194

Jeffrey D. Jonson
Rainbow Energy Marketing Corp.
919 7th St., Ste. 405
Bismark, ND 58504

Joe Wolfe (Alt)
Rainbow Energy Marketing Corp.
919 7th St., Ste. 405
Bismark, ND 58504

Leonard D. Rucker
General Manager
Reading Municipal Light Department
230 Ash Street
P.O. Box 150
Reading, MA 01867-0250

Vincent F. Cameron Jr.
Assistant General Manager - Energy and Operations
Reading Municipal Light Department
230 Ash Street
Reading, MA 01867-0250

William Seldon (Alt)
Reading Municipal Light Department
230 Ash Street
P.O. Box 150
Reading, MA 01867-0250

Scott Cline
Director, Asset Management and Regulatory Affairs
Reliant Energy Services, Inc.
1111 Louisiana, 9th floor
Houston, TX 77002
Guinette Haas (Alt)
Eastern Region, Asset Management
Reliant Energy Services, Inc.
1111 Louisiana, 9th floor
Houston, TX 77002

G. Robert Merry
Manager
Rowley Municipal Light Plant
47 Summer Street
Rowley, MA 01969

Roger W. Bacon (Alt)
Rowley Municipal Light Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Michael Schubiger
CEO
SESCO Enterprises, LLC
120 Wood Avenue South
Suite 511
Iselin, NJ 08830

Patrick Suseri
Executive Vice President
SESCO Enterprises, LLC
120 Wood Avenue South
Suite 511
Iselin, NJ 08830

Schaefer, Marc
c/o SESCO, Inc.
2 Elmwood Drive
Rutland, VT 05701

Thomas Halleran
Sempra Energy Trading Group
58 Commerce Road
Stamford, CT 06902

Mark Magyar (Alt)
Sempra Energy Trading Group
c/o Financial Management Group
325A Southbridge Street
Auburn, MA 01501

Thomas R. Josie
General Manager
Shrewsbury Electric Light Plant
100 Maple Avenue
Shrewsbury, MA 01545-5398

Roger W. Bacon (Alt)
Shrewsbury Electric Light Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Silkman, Richard
76 Main Street
Yarmouth, ME 04096

Mary J. Healey
State of Connecticut, **Office of Consumer Counsel**
Ten Franklin Square
New Britain, CT 06051

Nancy A. Harnick (Alt)
State of Connecticut, **Office of Consumer Counsel**
Ten Franklin Square
New Britain, CT 06051

Julie Hasham
Policy Development Specialist
State of Maine, Office of the Governor
38 State House Station
Augusta, ME 04333-0038

Stephen G. Ward (Alt)
Public Advocate
State of Maine, Office of the Governor
112 State House Station
Augusta, ME 04333

Wayne D. Doerpholz
Manager
South Hadley Electric Light Department
85 Main Street
South Hadley, MA 01075-2706

Roger W. Bacon (Alt)
South Hadley Electric Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

James Daly
Sprague Energy Corp.
Two International Drive
Portsmouth, NH 03801-6809

Jamie Cote (Alt)
Sprague Energy Corp.
Two International Drive
Portsmouth, NH 03801-6809

John Kilgo Jr.
Manager
Sterling Municipal Light Department
50 Main Street
Sterling, MA 01564-2129

Roger W. Bacon (Alt)
Sterling Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Matthew Morais
Strategic Energy Ltd.
Two Gateway Center
9th Floor
Pittsburgh, PA 15222

Michael Swider (Alt)
Strategic Energy Ltd.
33 Sleeper St., Apt. #303
Boston, MA 02210

R. Scott Whittemore
Manager Energy Services and Planning
Taunton Municipal Lighting Plant
55 Weir Street
P.O. Box 870
Taunton, MA 02780-0870

Brian Forshaw
Taunton Municipal Lighting Plant
c/o Connecticut Municipal Electric Energy Cooperative
30 Stott Avenue
Norwich, CT 06360-1535

Roger L. Buck
Executive Director
TEC-RI
7 Madeline Drive
Newport, RI 02840-1714

Michael Hoffer (Alt)
Vice Chairman Exec. Board
TEC-RI
7 Madeline Drive
Newport, RI 02840-1714

Gerald P. Skelton
Manager
Templeton Municipal Light Plant
School Street
Baldwinville, MA 01436

Roger W. Bacon (Alt)
Templeton Municipal Light Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Jeffrey Bergman
Utilities Manager
Texas Instruments
MS 10-04
34 Forest Street
Attleboro, MA 02703

Mark Sestak (Alt)
Facilities Engineer
Texas Instruments
MS 10-04
34 Forest Street
Attleboro, MA 02703

Jeffrey Bergman
The Energy Consortium
MS 10-04
34 Forest Street
Attleboro, MA 02703

Roger Borghesani (Alt)
Chairman
The Energy Consortium
24 Hastings Road
Lexington, MA 02421-6807

Mark T. Ladrow
Marketing Manager
Tractebel Energy Marketing, Inc.
15 New England Executive Park
Suite 205
Burlington, MA 01803

Chris Bergamini
Power Trader
TransAlta Energy Marketing (U.S.) Inc.
151 West Street
Suite 300
Annapolis, MD 21401

Dan LoBue
Power Trader
TransAlta Energy Marketing (U.S.) Inc.
151 West Street
Suite 300
Annapolis, MD 21401

William C. Taylor
Vice President
TransCanada Power Marketing Ltd.
110 Turnpike Road
Suite 203
Westborough, MA 01581

Michael E. Hachey (Alt)
Director, Power Marketing
TransCanada Power Marketing Ltd.
110 Turnpike Road
Suite 203
Westborough, MA 01581

Michael S. Grim
Director, Markets & Regulatory
TXU Portfolio Management Co. LP
1717 Main Street, Suite 17000
Dallas, TX 75201

Brian Agree (Alt)
TXU Portfolio Management Co. LP
1717 Main Street
Suite 2000
Dallas, TX 75201

Kevin M. Foley
General Manager
UAE Lowell Power LLC
2 Tanner Street
Lowell, MA 01852

Teri M. Pagano (Alt)
UAE Lowell Power LLC
c/o United American Energy Corp.
50 Tice Boulevard
Woodcliff Lake, NJ 07677

James Steffes
UBS AG
c/o UBS Warburg Energy LLC
1500 Louisiana Street
Houston, TX 77002

Deborah Donovan
Union of Concerned Scientists
c/o Synapse Energy Economics, Inc.
22 Pearl Street
Cambridge, MA 02139

Paul R. Peterson
Union of Concerned Scientists
c/o Synapse Energy Economics, Inc.
22 Pearl Street
Cambridge, MA 02139

Robert T. Gagliardi
Director, Strategic Policy
The United Illuminating Company
157 Church Street - 1-15D
P.O. Box 1564
New Haven, CT 06506-0901

Dennis Hrabchak (Alt)
Vice President Regulatory Policy
The United Illuminating Company
157 Church Street-15th Floor
P.O. Box 1564
New Haven, CT 06506-0901

David K. Foote
Vice President
Unitil Corporation Participant companies
6 Liberty Lane West
Hampton, NH 03842-1720

Thomas N. Wies
Vice President & General Counsel
Vermont Electric Power Company, Inc.
366 Pinnacle Ridge Road
Rutland, VT 05701

Gerald Spring (Alt)
Vermont Electric Power Company, Inc.
366 Pinnacle Ridge Road
Rutland, VT 05701

William J. Gallagher
General Manager
Vermont Public Power Supply Authority
P.O. Box 298
Waterbury Center, VT 05677

Brian Evans-Mongeon (Alt)
Manager of Power Supply & Marketing Service
Vermont Public Power Supply Authority
P.O. Box 298
Waterbury Center, VT 05677

Ron Armstrong
Virginia Electric and Power Company
5000 Dominion Blvd. 3N
Glen Allen, VA 23060

Michael Bekker (Alt)
Virginia Electric and Power Company
440 Windy Hill Road
Orange, CT 064770

William J. Wallace
Manager
Wakefield Municipal Gas and Light Department
9 Albion Street
P.O. Box 190
Wakefield, MA 01880-0390

Roger W. Bacon (Alt)
Wakefield Municipal Gas and Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Mark Noyes
WebGen Systems Inc.
41 William Linsky Way
Cambridge, MA 02142

Paul Taglianetti (Alt)
WebGen Systems Inc.
41 William Linsky Way
Cambridge, MA 02142

Joyce M. D. Wood (Alt)
Wellesley Municipal Lighting Plant
c/o Onway Lake Consulting
11 Forest Road
Raymond, NH 03077

John Scirpoli
Manager
West Boylston Municipal Lighting Plant
4 Crescent Street
West Boylston, MA 01583-1310

Roger W. Bacon (Alt)
West Boylston Municipal Lighting Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Daniel Golubek (Alt)
Manager
Westfield Gas and Electric Light Department
100 Elm Street
Westfield, MA 01085-2907

Roger W. Bacon (Alt)
Westfield Gas and Electric Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

David K. Singer
Williams Energy Marketing & Trading Company
One Williams Center
Tulsa, OK 74172

Dennis Keener (Alt)
Williams Energy Marketing & Trading Company
One Williams Center
Mail Drop 35-7
P.O. Box 3448
Tulsa, OK 74101-9567

Tim Charette
Power Marketing Executive
WPS Energy Services Inc.
1242 Lower Lyndon Street
Caribou, ME 04736

Ed Howard (Alt)
Power Marketing Executive
WPS Energy Services Inc.
1242 Lower Lyndon Street
Caribou, ME 04736

Non-Participant Transmission Customers

July 31, 2003

Miller Hydro Group
P.O. Box 97
Lisbon Falls, ME 04252-0097

Massachusetts Government Land Bank
Devens Commerce Center
43 Buena Vista
Ft. Devens, MA 01433

Groveland Municipal Light Department
23 School Street
Groveland, MA 01834

ATTACHMENT 11

New England Governors
and Utility Regulatory
and Related Agencies

July 31, 2003

Connecticut

The Honorable John G. Rowland
State Capitol
210 Capitol Ave.
Hartford, CT 06106

Connecticut Department of Public Utility Control
10 Franklin Square
New Britain, CT 06051-2605

Maine

The Honorable John Balducci
One State House Station
Rm. 236
Augusta, ME 04333-0001

Maine Public Utilities Commission
State House, Station 18
242 State Street
Augusta, ME 04333-0018

Massachusetts

The Honorable Mitt Romney
Office of the Governor
Rm. 360 State House
Boston, MA 02133

Massachusetts Department of Telecommunications and Energy
One South Station
Boston, MA 02110

New Hampshire

The Honorable Craig Benson
State House Rm. 208
Concord, NH 03301

New Hampshire Public Utilities Commission
8 Old Suncook Road - Building #1
Concord, NH 03301

Rhode Island

The Honorable Donald Carcieri
State House Rm. 143
Providence, RI 02903

Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Vermont

The Honorable James Douglas
109 State Street
Montpelier, VT 05609

Vermont Public Service Board
112 State Street, Drawer 20
Montpelier, VT 05620-2701

New England Governors
and Utility Regulatory
<u>and Related Agencies</u> **<u>July 31, 2003</u>**

Elia Germani, President
New England Conference of
Public Utilities Commissioners, Inc.
c/o Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Amy Ignatius, Esq.
Executive Director
New England Conference of
Public Utilities Commissioners, Inc.
One Eagle Square
Suite 514
Concord, NH 03301

Harvey L. Reiter, Esq.
Counsel for New England Conference
of Public Utilities Commissioners, Inc.
c/o MORRISON HECKER
1150 18th Street, N.W., Suite 800
Washington, DC 20036-3816

Power Planning Committee
New England Governors' Conference, Inc.
76 Summer Street, 2nd Floor
Boston, MA 02110

ATTACHMENT 12

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Pool) Docket No. ER03- -000
and ISO New England Inc.)

NOTICE OF FILING
(August , 2003)

Take notice that on July 31, 2003, the New England Power Pool (NEPOOL) Participants Committee and ISO New England Inc., submitted for filing changes to the New England Power Pool Agreement, including the NEPOOL Open Access Transmission Tariff (the "100th Agreement"). The 100th Agreement is designed to implement a comprehensive transmission cost allocation method for New England.

The NEPOOL Participants Committee states that copies of these materials were sent to the NEPOOL Participants, Non-Participant Transmission Customers and the New England state governors and regulatory commissions.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214). All such motions or protests must be filed in accordance with Section 35.8 of the Commission's regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection. This filing may also be viewed on the web at http://www.ferc.gov using the "FERRIS" link, select "Docket #" and follow the instructions (call 202-208-2222 for assistance). Comments, protests and interventions may be filed electronically via the Internet in lieu of paper. See, 18 CFR § 385.2001(a)(1)(iii) and the instructions on the Commission's web site under the "e-Filing" link.

Comment Date: August , 2003

Magalie R. Salas
Secretary