ATTACHMENT III

NEW BRUNSWICK POWER-
NEW YORK ISO - ISO-NEW ENGLAND
AGREEMENT ON ENHANCING COORDINATION OF SYSTEM OPERATION, PLANNING, AND MARKET DEVELOPMENT

THIS AGREEMENT, dated August 22, 2002 between New Brunswick Power Corporation ("NB Power"), the New York Independent System Operator, Inc. ("NYISO"), and ISO-New England ("ISO-NE"), establishes a Liaison Committee and outlines a plan for seeking increased coordination in the operation and planning of the inter-connected systems of the parties; it also confirms the mutual intention to seek compatibility in market structure and practices as the parties pursue market design processes within their respective jurisdictional frameworks.

BACKGROUND AND OBJECTIVES

A. NB Power is a Crown utility that owns and operates the transmission network in the province of New Brunswick and, historically and currently, is the principal supplier of electric energy in the province. In addition, NB Power exports electric energy to New England on many days to the full extent of existing ties. Rates of NB Power are regulated by the New Brunswick Board of Commissioners of Public Utilities ("Board").

B. NB Power is in the process of adopting an open access transmission tariff modeled on the Federal Energy Regulatory Commission ("FERC") *pro forma* tariff, which it anticipates filing with the Board in July 2002.

C. The province of New Brunswick is in the course of restructuring its electric power industry to introduce wholesale competition and, for industrial customers at the transmission level, retail competition. NB Power has been actively involved in the processes by which the province is examining and selecting market design alternatives. However, the selection of a market design model is the responsibility of (1) a government-instituted, multi-stakeholder market design committee (in which NB Power participated); and (2) ultimately, the provincial government.

D. The NYISO and ISO-NE are independent operators-administrators of transmission facilities and electric power markets in their respective service areas under the primary regulation of FERC. They are in the process of petitioning FERC for a determination that their combination into a Northeast Regional Transmission Organization ("NERTO") would meet FERC's criteria for becoming an approved Regional Transmission Organization ("RTO"). Such an RTO would also be under primary FERC regulation. NYISO and ISO-NE may be collectively referred to in this Agreement as the "NERTO parties."

E. The parties wish to identify a number of areas in which to explore mutually beneficial efficiencies and enhanced reliability of the systems they operate through increased coordination and harmonization of these systems and the markets they serve. The goal is to reduce impediments to the evolution of a natural, unified market encompassing the northeast U.S. states and adjacent Canadian provinces.

General Principles and Formation of Liaison Committee

1. Increased Integration of Services. The parties agree that customers doing business with the NERTO parties and NB Power as well as the public interest are best served through the provision of seamless, integrated transmission and wholesale power services between the NERTO parties and neighboring Canadian jurisdictions.

2. Reciprocal Accommodation of Market Designs. Towards the end of promoting broader regional trade in power, NB Power, will encourage the development of market structures, rules, and practices in New Brunswick that are similar to, or compatible with, those that are or become applicable to the NERTO parties and their market participants. Likewise, the NERTO parties will evaluate the development process in New Brunswick and, as appropriate, pursue accommodations or exceptions to otherwise applicable market design elements in the U.S. to meet the requirements of New Brunswick.

3. Liaison Committee. To facilitate communication of information on developments in their respective jurisdictions and to provide a forum for regular discussion in order to advance the objectives of this Agreement, each party shall appoint at least two individuals to serve on the New Brunswick - NERTO Liaison Committee ("Liaison Committee"). The first meeting of the Liaison Committee shall be held before December 31, 2002 at a mutually acceptable location. At its first meeting, the Liaison Committee shall establish business processes, a regular schedule of meetings for the Liaison Committee and shall develop a schedule for implementing the Near-Term and Intermediate-Term Objectives. The schedule may include intermediate milestones.

4. Cooperation with Other Areas. The parties recognize the existence of agreements and cooperative initiatives with other parties or coordinating bodies. The parties do not intend by virtue of this Agreement to in any way limit compliance with other agreements or preclude pursuit, individually or jointly, of other cooperative initiatives or arrangements.

Near-Term Objectives

5. Streamlining of Transaction Scheduling. The parties agree that streamlining the scheduling of transactions between New Brunswick and the NERTO parties' service areas is of significant benefit to customers. Accordingly, the parties will evaluate the development of an open scheduling system enabling "one-stop shopping" for inter-Control Area transactions (as well as other appropriate transactions). NB Power intends to participate in the ongoing open scheduling users group effort sponsored by the Northeast Power Coordinating Council (NPCC) CO-10 working group.

6. Expansion of Transfer Capability. The parties agree that expansion of transmission transfer capability between New Brunswick and ISO-NE is critical to improving markets, enhancing reliability, and permitting reserve sharing. The Liaison Committee will develop

recommendations and a proposed work plan for implementing expansion of the transmission corridor from New Brunswick to Boston.

7. Consolidation of Security Coordinator Function. Presently, ISO-NE serves as the Security Coordinator for New Brunswick. The parties agree that the Liaison Committee will document the elements of ISO-NE's present support, review how it may be modified, improved, and formalized, and develop a work plan for (a) accomplishing the selected improvements; and (b) transitioning the provision of the support to the NERTO, if the NERTO becomes functional.

8. Coordinating Calculation of Available Transfer Capability (ATC) / Total Transfer Capability (TTC). NB Power agrees to coordinate the calculation of ATC and TTC for the NERTO Interface with the NERTO parties with the goal of consistent calculation and the posting of the same values. The parties will consider posting the information either at a single website or, if at more than one website, ensuring that computations show a common result.

9. Integrated Area Control Error (ACE). The parties agree to continue and expand their work, currently conducted through the NPCC, to integrate ACE.

10. Coordination of Maintenance. The parties agree on the desirability of increasing coordination in planned outages for maintenance of transmission and generation facilities, including enhancing procedures for notification of outages, to minimize adverse impacts on power transactions and markets, subject to applicable codes of conduct.

Intermediate-Term Objectives

11. Reserve Sharing. The parties agree to explore opportunities for efficiencies and consumer cost reductions by sharing reserves within the NPCC region. The Liaison Committee will develop a report and recommendations for implementing this objective.

12. Joint System Planning. The parties agree that close coordination in bulk system planning is necessary to achieve a more integrated Northeast market and enhance both competition and reliability. To this end, the parties envision an open system planning process in which all regional transmission system operating authorities (as well as transmission owners, if different from system operators, regulators, and other stakeholders at appropriate stages) participate. In this process regional system expansion needs would be identified in a manner that employs common planning assumptions. The Liaison Committee will evaluate the best ways of achieving this objective.

Long-Term Objectives

13. Identification of Goals. The parties recognize and agree that there are a number of other important goals that are conducive to achieving an end state of seamless markets across all the NPCC Control Areas. However, the parties also acknowledge that New Brunswick has not yet completed its market redesign and industry restructuring process and that the role of NB Power *vis a vis* other institutions and market participants in the province has not yet been fully clarified by this process. Therefore, the parties agree that the following objectives and goals

merit exploration and discussion by the Liaison Committee pending more complete development of the New Brunswick restructuring process and greater clarification of NB Power's role in the future market structure:

- Achievement of common market design and common energy products.
- Single day-ahead commitment and real-time dispatch across the entire region.
- Elimination of barriers to trade
- Coordinated or consolidated market monitoring.

Miscellaneous

14. Term and Termination. This Agreement comes into effect on the date of the Agreement. Any party may terminate its participation in this Agreement upon sixty (60) days notice to each of the other parties.

15. Notices. Any notice under this Agreement shall be given in writing and delivered by overnight courier to the following addresses:

If to ISO-NE:
Kathleen A. Carrigan
Vice President, General Counsel and Corporate Secretary
ISO-NE
One Sullivan Rd.
Holyoke, Massachusetts. 01040
kcarrigan@iso-ne.com

If to NYISO:
Robert E. Fernandez
General Counsel and Secretary
NYISO
3890 Carman Rd.
Schenectady, New York 121303
rfernandez@nyiso.com

If to NB Power:
Wanda J. Harrison
Corporate Secretary and General Counsel
NB Power
515 King Street, P.O. Box 2000
Fredericton, NB E3B 4X1
wharrison@nbpower.com

16. Relationship of Parties The parties are not forming a partnership or other legal entity and no party is authorized by this Agreement to act as agent for any other party. Each party shall be responsible for all of its own expenses incurred in connection with this Agreement, including, but not limited to, the costs of travel to meetings, administrative costs, and legal or other consulting fees.

17. No Third Party Beneficiaries Nothing in this Agreement is intended for the benefit of third parties and no third party may claim for damages or otherwise to enforce any such benefit.

18. Successors. Upon its formation, NERTO will succeed to the rights and responsibilities of ISO-NE and NYISO under this Agreement. Otherwise, this Agreement may not be assigned by a party to this Agreement without the consent of the other parties which consent shall not be unreasonably withheld.

EXECUTION

The parties have executed this agreement on 08-22-02.

NEW BRUNSWICK POWER CORPORATION

By: Stewart MacPherson
Title: President and CEO

ISO NEW ENGLAND INC.

By: Gordon vanWelie
Title: President and CEO

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC.

By: William J. Museler
Title: President and CEO

ATTACHMENT IV

This Attachment has been prepared by ISO New England Inc. ("ISO-NE") to demonstrate the means by which the foregoing Petition meets the conditions set forth in Section 3.2(a) of "Amendment No. 3 to Interim Independent System Operator Agreement" dated April 30, 2002 between NEPOOL and ISO-NE (the "Amendment").

Section 3.2(a) requires that, on or before November 1, 2002, ISO-NE make a filing with the Commission outlining a proposed structure for an RTO that includes at least the NEPOOL Control Area. Section 3.2(a) provides that this condition will be satisfied if the filing minimally includes the components outlined in the left-hand side of the chart set out below. The right-hand side of the chart identifies the section of the Petition which contains each component. Therefore, having included each of the identified components in the Petition, ISO-NE has satisfied the condition contained in Section 3.2(a) of the Amendment.

Condition	**Section of Petition**
Results of cost/benefit analysis	Section VIII.B.1 and Attachment X
Detailed explanation of the rationale for the proposed combination of the New York and New England markets	Sections I.C. and IV.A
Rights, responsibilities and authorities of the RTO	See entire Petition, especially Sections V.A., V.E, VI.D and VIII.E. through L
Rights, responsibilities and authorities of customers of the RTO	See entire Petition, especially Sections V.C.1 and F
Rights, responsibilities and authorities of other organizations (e.g., ITCs) to be accommodated under the new structure	Sections V.F.2, VI.E and VII
Identification of changes in the market design in NE from SMD proposed as of 3/1/02	See attachment
Projected work plan and timeline for the creation of RTO, including entities proposed to accomplish each of the tasks in the work plan	Section I.A., Section V.B, Section V.C.2, Section VI.B and Attachment VIII
Discussion of why the ISO believes that the proposed RTO meets each of the requirements on FERC Order No. 2000	Section VIII

COMPARISON OF MARKET DESIGN FOR NEW ENGLAND REFLECTED IN NERTO PETITION (I.E., SMD 1.0 AS REFLECTED IN JULY 15, 2002 FILING BY NEPOOL AND ISO-NE) WITH THE VERSION OF SMD PROPOSED AS OF MARCH 1, 2002 (I.E., MARKET RULE 1X AS FILED WITH THE COMMISSION IN JUNE 2001)

Section of 1X	COMMENT
1. Market Operations	
1.1	• Revised language pertaining to SMD Effective Date to accommodate possible staging of ICAP Market. • Added reliability criteria language
1.3	• Revised definitions to reflect modifications throughout document.
1.7.6	• Conforming changes for defined terms. • Modified language to provide more flexibility in dealing with procedural conflicts with neighboring control areas.
1.7.7	• Conforming changes for defined terms. • Added description of loss costs and Loss Revenue.
1.7.8	• Added language to explicitly provide for Self-Scheduling.
1.7.9	• External Buyer concept not used in SMD. External Transactions are used.
1.7.10	• Clarifying changes to distinguish between External Transactions and internal transactions. • Deleted netted language; settlements section automatically provides for netting.
1.7.17	• Modified section to reference NEPOOL Manuals for operating reserve requirements.
1.7.18	• Clarified Regulating Unit Limit adjustments. • Removed reference to fast response units.

Section of 1X	COMMENT
1.7.19	• Clarified language to reflect treatment in software. • Added reference to sanctions appendix.
1.7.19A	• Reserved Section for Spinning Reserve Market.
1.7.20	• Clarified use of Internal Bilateral and External Transaction terms. • Clarified Participant responsibilities
1.10.1	• Conforming changes for defined terms. • Modifications to clarify implementation of “up to” congestion bids for External Transactions. • Clarify scheduling procedures for resources with long start-up notification times.
1.10.1A	• Conforming changes for defined terms. • Modifications to reflect implementation of External Transactions in Day Ahead market and real-time scheduling. • Modifications to bidding rules to reflect implementation of bid caps in energy and regulation markets. • Clarify that external resources must have dynamic schedule to be dispatched by ISO; otherwise resources must be block loaded. • Clarify the Supply Offer rules apply to all Resources. • Clarify Supply Offer parameter rules (min-run time, notification time and unit operating limits). • Limit ISO Load Forecast reporting to next Operating Day.
1.10.2	• Conforming changes for defined terms. • Removed reference to Self-Schedules. Language not applicable. • All sales External to Control Area backed by ICAP Resources are subject to recall in an Emergency. • Added Limited Energy Resource

Section of 1X	COMMENT
	optimization language. • Clarified treatment of cancelled starts.
1.10.3	• Add language clarifying self-schedule resources ineligible for Operating Reserve Credits. • Clarified remaining Self-Schedule language to allow for partial Self-Schedules. • Clarified that Real-Time Energy deviations may be supplied via internal bilateral transactions.
1.10.4	• Conforming changes to reflect defined terms. • Clarified when units receive a Forced Outage. • Clarified that Real-Time Energy deviations may be replaced via internal bilateral transactions. • Deleted language that self-scheduled resources do not receive Operating Reserve Credit for Start-up and No-Load. Covered under 1.10.3.
1.10.5	• Clarify that external resources must have dynamic scheduling capability to be dispatched by ISO; otherwise resources must be block loaded. • Clarified that Real-Time Energy deviations may be supplied via internal bilateral transactions.
1.10.6	• Deleted External Buyer reference. Not applicable.
1.10.7	• Modifications to reflect implementation of External Transactions in Day Ahead market and real-time scheduling.
1.10.8	• Delete provisions for hydro scheduling reporting. • Added reference to Replacement Reserve. • Expanded deadline for Day-Ahead Market clearing to allow for un-foreseen events.

Section of 1X	COMMENT
	• Clarified information posting requirements.
1.10.9	• Clarify re-offer and re-bidding provisions. • Expanded deadline for re-offer period to allow for un-foreseen events. • Remove existing provision on external transaction scheduling; inconsistent with implementation.
1.11.3	• Clarified Limited Energy Generation provisions. • Add provision to allow ISO to re-declare operating parameters in real time based on actual performance (modeled from existing provision in MRP 14).
1.11.3A	• Make provision for recall consistent with OP4 procedures allowing recall in anticipation of Max Gen Emergency.
1.11.4	• Conforming changes for defined terms. • Added reliability criteria to selection of Regulating units.
1.11.4A	• Reserved for spinning reserve market.
1.12	• Insert provisions defining dynamic scheduling requirements.
2. Calculation of Locational Marginal prices	
2.1	• Conforming changes for defined terms.
2.2	• Conforming changes for defined terms. • Modify text so general provisions apply to both day ahead and real time markets.
2.3	• Clarify that provision applies to both day ahead and real time markets.
2.4	• Conforming changes for defined terms. • Clarify provisions on nodal price calculations

Section of 1X	COMMENT
	to reflect software implementation, including rules for Resource eligibility to set Real-Time LMP.
2.5	• Conforming changes for defined terms. • Clarify provisions on nodal price calculations to reflect software implementation. • Add provision for setting LMPs during minimum generation conditions and Maximum Generation Emergency conditions in real-time.
2.6	• Conforming changes for defined terms.
2.7	• Add provisions for calculating zonal prices.
2.8	• Add provisions for defining hubs and calculating hub prices.
2.9	• Added section defining ISO responsibilities for finalizing Real-Time LMPs.
2.10	• Conforming changes for defined terms. • Specified timing of first Evaluation Report.
3. Accounting & Billing	
3.2.1	• Conforming changes to reflect defined terms. • Modify description of calculations to more accurately reflect terminology used in settlements process. • Modified Loss Revenue allocation.
3.2.2	• Conforming changes for defined terms • Minor edits to clarify language.
3.2.3	• Clarify treatment of Dispatchable Loads in day ahead schedule for reserves. • Clarify calculation of former net commitment period compensation costs to reflect implementation. • Eliminate NCPC terminology. Now

Section of 1X	COMMENT
	Operating Reserve Credits. • Modified charge and credit calculations for units providing voltage or VAR support. • Add provisions to compensate postured generators. • Modify and add provisions to describe determination of operating reserve payments and assignments and caps applied during system emergencies. • Clarify deviation calculations for generators for use in allocation of Real-Time Operating Reserve costs.
3.2.3A	• Add provisions describing implementation of Spinning Reserve Market.
3.2.6	• Revise allocation of emergency purchase and sales costs to be consistent with allocation of Real-Time Operating Reserve costs.
3.2.7	• Added references to NEPOOL Billing Policy (Attachment N to NEPOOL Tariff).
3.4.2	• Conforming changes for defined terms and minor clarifying language changes.
3.4.3	• Added references to NEPOOL Billing Policy (Attachment N to NEPOOL Tariff).
3.6.2	• Add provision to allow Participants to revise previously submitted internal contract submissions after-the-fact.
4. Rate Table	
4.1	• Add provision to define offers used to calculate clearing prices.
4.3	• Add a provision allowing ISO to negotiate prices with providers of emergency energy.

Section of 1X	COMMENT
5. Calculation of Transmission Congestion Revenue & Credits	
5.1.4	• Modified Section 5.1.4 to address the calculation of Congestion Costs for Non-Participant Transmission Customers.
5.2.1	• Moved the eligibility exception for receiving Transmission Congestion Credits from Section 5.2.1 to Appendix A.
5.2.2	• Added detail on how an entity becomes a registered FTR Holder to Section 5.2.2.
5.2.5	• Added a subsection to Section 5.2.5 that defines the total Transmission Congestion Revenue available for the month.
5.2.6	• Added clarification to Section 5.2.6 concerning the distribution of excess congestion revenue. 1. If there is any excess at the end of the calendar year, this amount will be proportionally allocated to any remaining unpaid monthly positive target allocations in any month of that year, but will not exceed the amount of each unpaid monthly positive target allocation. 2. Any remaining excess will be allocated to the entities who paid Congestion Costs in that calendar year in proportion the amount of total Congestion Costs paid during the year.
6. Reliability Must Run Resources	
6.1	• Clarify definition of RMR resources.
6.2	• Add a provision authorizing ISO to classify a resource as an RMR resource and use of Appendix A for RMR price mitigation.

Section of 1X	COMMENT
6.4.4	• Clarify description of RMR cost allocation including options for collection of RMR Contract fixed costs.
7. Financial Transmission Rights Auctions	
7.1	• Section 7.1: Added an FTR Registration Fee for Non-Participants that want to participate in the FTR Auction or to become an FTR Holder via the secondary market.
7.1.1	• Modified the timing of the FTR Auctions such that long-term FTR Auctions will be introduced no later than seven months after the SMD Effective Date. • Modified the start and end dates of the long-term FTRs to be auctioned such that they are coordinated with those of long-term FTRs of neighboring Control Areas. • Eliminated the five year (in one-year increments) FTR Auctions and established that within two years from the SMD Effective Date the ISO will evaluate making available FTRs with a term of more than one year (in one-year increments).
7.1.2	• Modified the bidding windows for the FTR Auctions.
7.3.5	• Added the requirement that a bid to purchase an FTR may not specify a negative price per megawatt. • Changed the requirement that bids and offers for FTRs be specified to the nearest megawatt to FTRs be specified to the nearest 0.1 megawatt.
7.3.7	• Modified the time that the announcement of FTR winners and prices for long-term FTRs will be posted by the ISO from four days to six days. Later than six days must be approved by ISO Board.

Section of 1X	COMMENT
7.3.10	• Clarify the impacts of generation outages on simultaneous feasibility test.
7.3.13	• Added Section 7.3.13 concerning the FTR secondary trading market and clarified that FTRs may not be re-configured, only sub-divided.
8. Installed Capacity	
8	• Insert Installed Capacity Provisions based on NY ISO ICAP Requirements.

Section of 1X	COMMENT
Appendix A	• Created Appendix A from existing market power monitoring and mitigation rules (MRP 17) and NY ISO mitigation rules.
Appendix B	• Created Appendix B from existing market rules on sanctions and penalties (MRP 13).
Appendix C	• Created Appendix C from Schedule 15 describing and updated to reflect the ARR allocation implementation • Added a clarification which states that if the party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transaction does not elect the special treatment in stage one of the ARR Allocation process that the load and generation source associated with the Excepted Transaction will be treated the same as all other load and generation (with the exception of NEMA Contracts) in the four stage ARR Allocation process. • Added a clarification, which states that Excepted Transactions will not be permitted to use their existing contract rights for physical scheduling of a transaction. • Modified the four-stage ARR Allocation process from using Monthly Peak Load to using load distribution from the network model and Real-Time Load Obligation excluding External Transaction sales in the various stages of the process. [The MW quantity of ARRs allocated to each Node will be based on the load distribution in the network model used for the FTR Auction for month being settled. The load distribution in the network model and the prices from the FTR Auction will be used to determine the pot of FTR Auction Revenues to be allocated to the Load Zone. After honoring the Excepted Transactions requesting special treatment and the NEMA Contracts, the remaining dollars so allocated to the Load Zone will be distributed within the Load Zone to the ARR Holders in proportion to their Real-Time Load

Section of 1X	COMMENT
	Obligation excluding External Transaction sales in the Load Zone at the time of the NEPOOL coincident peak for the month being settled less adjustments for Excepted Transactions and NEMA Contracts.] • Since the four-stage ARR Allocation process will not be inherently revenue neutral, added a proportional adjustment to the process in order to distribute all available FTR Auction Revenues each month. The proportional adjustment will be applied to ARRs awarded in the four-stage ARR Allocation process only. • Added detail on Qualified Upgrade Awards (QUAs), formerly incremental ARRs. .
Appendix D	• Created Appendix D from existing ADR procedures.
Appendix E	• Created Appendix E for Load Response Program to be implemented under SMD.

ATTACHMENT V

NORTHEASTERN REGIONAL TRANSMISSION ORGANIZATION CODE OF CONDUCT

1. NERTO EMPLOYEES' OBLIGATIONS; NON-DISCRIMINATORY TRANSMISSION SERVICE

This Code of Conduct shall apply to NERTO Employees and shall provide policies, rules and procedures to be followed in carrying out the NERTO's responsibilities under its Tariff and other governing documents. Capitalized terms shall have the meanings given them in Section 2 hereof or, if not defined herein, in the Tariff.

The statements made in this Code of Conduct do not constitute any form of an employment contract. The NERTO's requirement that directors and certain consultants or contractors of the NERTO who fall within the definition of "NERTO Employee" comply with this Code of Conduct does not make those individuals employees of the NERTO. It merely means that, in performing their jobs, they must adhere to the rules and policies set forth herein. This or any other stated policy may be changed unilaterally by the NERTO at any time, without prior notice.

NERTO Employees shall:

1. take all reasonable actions within their authority under the Tariff and the NERTO Agreement necessary to comply with all laws including, without limitation, the following: federal and state environmental laws; Federal Power Act and FERC rules and regulations; 18 C.F.R. Sections 37.1-37.4; and federal securities laws;

2. take all reasonable actions within their authority under the Tariff and the NERTO Agreement necessary to, in accordance with this Section 1, provide non-discriminatory Transmission Service pursuant to the Tariff, acting as the Responsible Party for all Transmission Owners that are signatories to the TOA and operate the OASIS;

3. refrain from energy transactions in accordance with Section 3.2.2, below;

4. treat Confidential Information in accordance with Section 4, below;

5. protect the integrity of NERTO Records in accordance with Section 7, below;

6. protect the NERTO's assets, including property, facilities, equipment and supplies, by using NERTO property and other assets only for NERTO-related business; and

7. avoid improper relationships, including those with Market Participants, which could cause or appear to cause a conflict of interest, in accordance with Section 3, below.

It is the policy of the NERTO to offer open-access Transmission Service under the Tariff in a non-discriminatory manner to all Market Participants. In compliance with this policy, all NERTO Employees must administer the Tariff and related agreements with impartiality toward all Market Participants.

Any Tariff provision relating to Transmission Service which, by its terms, does not provide for the exercise of discretion must be strictly enforced. If any discretion is given in the application of a Tariff provision relating to the transmission of electricity, that Tariff provision is to be applied in substantially the same manner to all similarly situated persons.

Where the Tariff allows for the exercise of discretion in its application, to the extent that discretion is exercised, NERTO Employees are required to maintain a written log of each waiver or act of discretion, the circumstances involved, the person authorizing the waiver and the source of authority for the waiver. The NERTO shall post information on the OASIS for a period of ninety (90) days, detailing the circumstances and manner under which that discretion was exercised, and shall thereafter make this information available for review on request, but not on the OASIS, for three (3) years from the date it is first posted.

Unless the context of the Code of Conduct otherwise requires, words of any gender include each other gender.

2. DEFINITIONS

As used in this Code of Conduct, the following terms shall have the following meanings (such meanings to be equally applicable to both the singular and plural forms of the terms defined):

"Affiliate," with respect to an entity, means any individual, corporation, partnership, firm, joint venture, association, joint-stock company, trust or unincorporated organization, or other form of entity, directly or indirectly Controlling, Controlled by, or under common Control with, such entity.

"Associated" shall have the meaning given it in Section 3.2.2.

"Confidential Information" shall have the meaning given it in Section 4.1.

"Control" means the possession, directly or indirectly, of the power to direct the management or policies of an entity. A voting interest of ten percent or more creates a rebuttable presumption of control.

"FERC" means the Federal Energy Regulatory Commission.

"Immediate Family" refers to a NERTO Employee's spouse and minor children.

"Market Participant" refers to any person (natural or legal) transacting with the NERTO to buy, sell or schedule electric generating Capacity and/or Energy, Ancillary Services or Transmission Services. The term includes, but is not limited to, Power Exchanges, power brokers, power marketers, Buyers, Sellers, Transmission Owners, Non-Utility Generators, Independent Power Producers, load aggregators, Load Serving Entities, and municipalities or groups of these entities. The NERTO has posted on its website a list of the current Market Participants, Transmission Customers, other than any such Transmission Customers solely taking Through Service under the Tariff, and their respective Affiliates. The NERTO will keep such list reasonably up to date.

"NERTO" means the Northeastern Regional Transmission Organization.

"NERTO Agreement" [to be defined].

"NERTO Compliance Officer" means the NERTO employee designated by the Audit and Finance Committee of the Board of Directors as responsible for interpreting and ensuring compliance with the Code of Conduct.

"NERTO Employee" includes directors, officers, and employees of the NERTO, except where otherwise noted. Contract workers, individual consultants, and employees of consulting firms who are expected to work with the NERTO for more than ____ hours, including vacation and sick leave, will be considered to be NERTO Employees under this Code of Conduct.

"NERTO Records" consist of all documents submitted to, or generated by, the NERTO that pertain to NERTO business. Examples of NERTO Records include, without limitation, requests for Transmission and Ancillary Services, service agreements, system impact studies and facilities studies, audit records, and NERTO annual reports.

"OASIS" means the NERTO's Open Access Same Time Information System.

"Prohibited Financial Interest" shall have the meaning given it in Section 3.1.

"Responsible Party," as defined in Order No. 889, means the Transmission Owner or an agent to whom the Transmission Owner has delegated the responsibility of meeting the requirements of 18 C.F.R. §37 concerning the operation of the OASIS.

"Secondary Employment" means, while an individual is a NERTO employee, participation in a paid or unpaid second job (part-time, full-time or project related).

"Securities" refer to stocks, stock options, bonds and any other instruments of debt or equity, and include all interests in debt or equity instruments, including, without limitation, secured and unsecured bonds, debentures, notes, securitized assets, commercial paper, preferred and common stock, any beneficial or legal interest derived from a trust, any right to acquire any long or short position in such securities including, without limitation, interests convertible into the aforementioned securities, options, rights, warrants, puts, calls and straddles with respect to such securities.

"Tariff" refers to the NERTO Open Access Transmission Tariff on file with the FERC.

"TOA" means the Transmission Operating Agreement between the NERTO and the transmission owners that are signatories thereto.

"Transmission System Information" or **"TSI"** has the meaning given it in Section 4.1.

3. CONFLICTS OF INTEREST

Certain contacts between NERTO Employees and Market Participants may constitute or appear to constitute a conflict of interest. Potential conflicts of interest and the NERTO's ability to restrict actions and duties to avoid potential conflicts are discussed below.

3.1 Prohibited Financial Interests

A Prohibited Financial Interest is the ownership of Securities of Market Participants or their Affiliates, whether ownership is direct or through participation in mutual funds concentrating in investments in Market Participants or their Affiliates.

Prohibited Financial Interests do not include interests in a publicly traded or publicly available mutual fund or other collective investment fund or in a widely held pension or similar fund, provided that the fund's prospectus does not indicate the objective or practice of concentrating its investment in Market Participants or similar entities and the NERTO Employee does not have the ability to exercise control over the financial interests held in the fund. Prohibited Financial Interests also exclude the Securities of a Market Participant or Affiliate which have been purchased by a NERTO Employee's spouse who is employed by a Market Participant or any of its Affiliates and is required to purchase Securities of such Market Participant or any of its Affiliates as a part of employment, provided that any such purchase by a spouse must be disclosed to the NERTO Board, which shall have the authority to consider appropriate limitations on the duties of the NERTO Employee to avoid a conflict of interest.

3.2 Restrictions on Prohibited Financial Interests

In order for the NERTO to remain truly independent, free of any control or appearance of control over the decision-making process by any individual Market Participant, NERTO Employees must strictly observe the following rules.

3.2.1 No Prohibited Financial Interests

No NERTO Employee or member of his Immediate Family shall have a Prohibited Financial Interest. [However, matching contributions made in the Securities of a Market Participant in connection with any savings, pension or 401(k) plans of a former employee of a Market Participant shall be permitted until the completion of the transfer, spin off or merger of assets and liabilities of such plans to new plans maintained by the NERTO. -- *Being reviewed for continuing applicability.]*

3.2.2 No Association with Market Participants

No NERTO Employee shall be Associated with any Market Participant or any of its Affiliates. For the purposes of this paragraph, a NERTO Employee shall be deemed "Associated" with a Market Participant or any of its Affiliates if: (1) the NERTO Employee or his spouse is an officer, director, partner, or employee of a Market Participant or any of its

Affiliates, provided that a NERTO Employee shall not be deemed "Associated" with a Market Participant or any of its Affiliates if his spouse was, as of [DATE?], a director, officer, employee or partner of a Market Participant or any of its Affiliates and such NERTO Employee discloses such relationship to the NERTO Compliance Officer, who shall have the authority to consider appropriate limitations on the duties of such NERTO Employee, including, changing his duties, to avoid an appearance of a conflict; (2) the NERTO Employee is a former executive officer of a Market Participant or any of its Affiliates, and is receiving continuing benefits under an existing employee benefit plan (other than a defined benefit pension plan or other plan pursuant to which the benefits are independent of the financial condition of the Market Participant or any of its Affiliates and pension payments are distributed to the former executive officer by a trustee, not as compensation but in accordance with the rules of the pension plan), arrangement or policy of the Market Participant or any of its Affiliates; (3) a member of the NERTO Board of Directors has served as a former officer, director, partner, or employee of a Market Participant or any of its Affiliates within the two-year period immediately preceding his proposed election to the NERTO's Board of Directors; or (4) the NERTO Employee has a material ongoing business or professional relationship with a Market Participant or any of its Affiliates (including employees of Market Participants or any of its Affiliates).

To ensure that the NERTO and the NERTO Employees maintain independence from any Market Participant, the NERTO and the NERTO Employees are prohibited from engaging in any energy transactions other than in the performance of duties under the NERTO Tariff. This provision shall not, however, prevent the NERTO or NERTO Employees from purchasing electricity, power and energy as retail customers for their own account and consumption from a Market Participant or any of its Affiliates.

3.2.3 Divestiture of Prohibited Financial Interests

If a NERTO Employee or his Immediate Family has a Prohibited Financial Interest, divestiture must occur as follows: (1) within six months of the effective date of the NERTO Tariff; (2) for new NERTO Employees, within six months of commencement of employment; (3) if a Prohibited Financial Interest results from an entity becoming a Market Participant, within six months of receipt of the NERTO's list referencing such Securities; and (4) if a Prohibited Financial Interest results from a gift, inheritance, distribution of marital property or other involuntary acquisition, within six months of the acquisition.

3.3 Political Activities

NERTO Employees are not restricted from participating in any legal political activity so long as they do not purport, directly or indirectly, to represent the NERTO without authorization. A NERTO Employee should not participate in political activities as a representative of the NERTO, unless specifically authorized to do so, or use corporate funds or resources for support of particular political parties or candidates or seek reimbursement from NERTO for political contributions.

NERTO Employees are not precluded from holding public office as long as they notify the NERTO Compliance Officer or his designee in writing upon accepting public office. The NERTO Employee's work in the public office must not detract from the NERTO Employee's performance in connection with the NERTO, and the NERTO Employee shall not represent the NERTO in his capacity as a public official and shall not use NERTO resources for work related to the public office. Any NERTO Employee holding a public office shall abstain from voting or participating in any debate or in matters relating to the NERTO as part of his duties in public office.

3.4 Secondary Employment

NERTO Employees shall not take Secondary Employment unless the employment: (1) will not embarrass or discredit the NERTO; (2) will not interfere with the NERTO Employee's duties or involve the use of NERTO resources, materials or assets; (3) will not create a conflict of interest for the NERTO or the NERTO Employee; (4) will not result in any Market Participant receiving an advantage, real or apparent, over other Market Participants with respect to the NERTO; and (5) is fully disclosed to the NERTO prior to commencement of Secondary Employment and the NERTO Compliance Officer or his designee determines that the criteria of (1) through (4) are met and then authorizes the Secondary Employment in writing.

It will be considered a conflict of interest to engage in any outside activity that interferes with or materially decreases impartiality, judgment, effectiveness, productivity or ability to perform duties and functions at the NERTO. It will also be considered a conflict of interest for a NERTO Employee who is simultaneously employed or engaged in other business activities with any other person, business, enterprise or concern to transact business with the NERTO on behalf of such other person, business, enterprise or concern, or to engage other NERTO Employees in any outside business activity that interferes with or materially decreases impartiality, judgment or effectiveness or creates a conflict of interest, an appearance of a conflict of interest or interferes with the productivity or ability of other NERTO Employees to perform their duties and functions at the NERTO.

Where a NERTO Employee takes Secondary Employment with a non-Market Participant, that NERTO Employee may not transact business with the NERTO on behalf of the Secondary Employer.

The NERTO's policy on Secondary Employment is not intended to discourage or prohibit NERTO Employees from engaging or participating in civic, church or other charitable organizations, provided such activities or positions do not interfere with such NERTO Employees' duties and functions at the NERTO.

3.5 Other Conflicts of Interest

It will be considered a conflict of interest if a NERTO Employee requests or accepts anything of more than nominal value, including but not limited to money, a loan or discount, vacations, property, contributions, goods or services from a Market Participant or any of its Affiliates or any other person or entity doing business with the NERTO. Such gifts should be returned or offers declined, with an appropriate explanation.

If a gift from a Market Participant is not returnable (e.g., perishable), such gift should be given to a NERTO supervisor or the NERTO Compliance Officer or his designee for donation to a charity or destruction. Acceptance of an occasional business-related meal or entertainment is permissible when the value involved is not significant and clearly does not create any obligation to the donor.

A NERTO Employee seeking other employment, or having an arrangement concerning prospective employment, with a Market Participant or any of its Affiliates must notify his supervisor and disqualify himself from participating in any matter that will have an effect on the financial interests of such Market Participant or any of its Affiliates.

For a period of two years immediately following cessation of employment with the NERTO, former NERTO Employees may not, directly or indirectly, induce or attempt to induce any current NERTO Employee to leave the NERTO, interfere with the relationship between the NERTO and said party, or induce or attempt to induce any NERTO customer, supplier, contractor or consultant to cease doing business with the NERTO.

3.6 Consultants and Contractors

The NERTO Board shall apply reasonable and objective criteria when issuing conflicts of interest screening guidelines for consultants and contractors who are not included within the definition of "NERTO Employees." In applying the guidelines to individual cases, the NERTO Board will consider the nature of the services provided by the consultant or contractor, the length of the engagement, whether the consultant or contractor is required to comply with his own professional conflict of interest standard (e.g., attorneys, accountants, etc.), and whether the consultant or contractor will have access to Confidential Information. The screening guidelines will be made known to the appropriate NERTO Employees authorized to enter into contracts for outside services, and implementation of the Board's criteria will be monitored by the NERTO Compliance Officer or his designee.

It will be considered a conflict of interest for a NERTO Employee, or his Immediate Family, or, to his knowledge, any other member of his family or relative, to have an interest in any contractor, company, business, or enterprise which has, or is seeking to establish, business relations with the NERTO, unless that relationship has been disclosed to the NERTO Compliance Officer or his designee and approved by the Audit and Finance Committee of the Board of Directors.

4. TREATMENT OF CONFIDENTIAL INFORMATION

This Section deals with Confidential Information, including Transmission System Information.

4.1 Confidential Information

Confidential Information consists of: (1) data designated as such by the NERTO; (2) any commercially sensitive information including, without limitation, trade secrets, business strategies, and Generator-specific information such as heat rates, cost information, bid prices, bid blocks and times, and information regarding fuel availability, all of which is affirmatively designated as Confidential Information by its supplier or owner; and (3) Transmission System Information ("TSI") that has not yet been posted on the OASIS or provided in some public forum such as in a FERC filing. TSI is information that: (1) is commercially valuable and (2) access to which is necessary to buy, sell or schedule Energy, Capacity, Ancillary Services or Transmission Service. Examples of TSI include, but are not limited to, the following:

- Available Transfer Capability;
- Total Transfer Capability;
- information regarding physical Curtailments and Interruptions;
- information regarding Ancillary Services;
- pricing for Transmission Service; and
- discounts offered.

4.2 Disclosure of Confidential Information to Market Participants

In the course of responding to requests for Energy, Capacity, Transmission Services or Ancillary Services, the NERTO shall not disclose Confidential Information to any Market Participant. The NERTO shall disclose data that is not Confidential Information, and information required to be publicly disclosed by the FERC, by posting the information on the OASIS. If a NERTO Employee improperly discloses TSI to any Market Participant, the NERTO shall immediately post the information on the OASIS and notify the FERC. NERTO Employees shall also report all improper disclosures of Confidential Information to the NERTO Compliance Officer or his designee immediately.

The procedures described in this Section do not apply to the following:

1. communications of TSI between the NERTO and the Transmission Owner's control centers, other power pools or ISOs or RTOs;

2. communication of information from a Market Participant to the NERTO;

3. information that is no longer Confidential Information because it has been made public by its posting on the OASIS, or it was legally disclosed by a third party in good faith and without violating a trade secret, secrecy agreement or employment contract with a non-disclosure clause, or it was made public by a government agency, court or other process of law;

4. requests by a Market Participant for a report regarding the status of that Market Participant's particular contracts or transactions. The NERTO shall provide all Market Participants making such a request with a report of the same type and with the same level of detail; and

5. information that has not been designated by the supplier or owner as Confidential Information.

4.3 Disclosure of Confidential Information to Regulators

If Confidential Information is required to be divulged in compliance with an order or a subpoena of a court or regulatory body other than the FERC, the NERTO will provide such information after giving notice to the affected Market Participants so that they may seek to obtain a protective order or other appropriate protective relief from the court or regulatory body. If the FERC or its staff, during the course of an investigation or otherwise, requests information from the NERTO that is otherwise required to be maintained as Confidential Information pursuant to this Section, the NERTO shall provide the requested information to the FERC or its staff within the time provided in the request for information. In providing the information to the FERC, the NERTO shall, consistent with any FERC rules or regulations that may provide for privileged treatment of that information, request that the information be treated as confidential and non-public by the FERC and that the information be withheld from public disclosure. The NERTO shall not be held liable for any losses, consequential or otherwise, resulting from the NERTO divulging such Confidential Information pursuant to a request under this paragraph.

After the Confidential Information has been provided to the FERC, the NERTO shall immediately notify any affected Market Participant(s) when the NERTO becomes aware that a request for disclosure of such Confidential Information has been received by the FERC or a decision to disclose such Confidential Information has been made by the FERC, at which time the NERTO and the affected Market Participant(s) may respond before such information would be made public, pursuant to the FERC's rules and regulations that may provide for privileged treatment of information provided to the FERC.

The NERTO shall establish procedures for handling Confidential Information that minimize the possibility of intentional or accidental disclosure of Confidential Information.

4.4 Termination of Association

The NERTO may require, as a prerequisite to their association, that NERTO Employees who will have access to Confidential Information agree to reasonable restrictions on future employment following their association with the NERTO. Upon termination of association with the NERTO, a NERTO Employee shall not disclose Confidential Information to any person outside of the NERTO, or use Confidential Information in any manner for personal benefit or for the benefit of a third party.

5. INSIDER TRADING

This Section defines insider trading, explains the duties of NERTO Employees and describes behavior that is prohibited under securities laws.

5.1 Insider Information

Federal laws prohibit the purchase or sale of any publicly traded security by a person in possession of important information about the security or its issuer that is not publicly known. These laws have special significance to the NERTO because NERTO Employees routinely learn Confidential Information about Market Participants and others. This circumstance creates two duties for all NERTO Employees: (1) a duty not to trade while in possession of "material, nonpublic information," also known as "inside information" or "insider information," as defined below, and (2) a duty not to communicate such information to anyone outside of the NERTO, also known as "tipping." It has been and remains the policy of the NERTO that there be scrupulous compliance with each of these duties.

Material: Much of the information obtained about Market Participants and their Affiliates may be material information under the law. Information is material if a reasonable investor would consider it important in determining whether to buy or sell the securities of the company involved. The information may be either positive or negative. If the information would affect the price of the stock, it is material. If the information makes anyone consider buying or selling the stock, that is probably the best indication that it is material. Some examples of information that could be considered material are key personnel changes, earnings information, proposed mergers or acquisitions and financial or credit status. If in doubt, one should assume that any information which could have any significance to an investor is material, and should not purchase or sell or allow anyone else to purchase or sell the securities in question until such information has been made public.

Nonpublic: Information that has not been disclosed to the public generally is nonpublic. To show that information is public, one should be able to point to some evidence that it is widely disseminated. Information would generally be deemed widely disseminated if it has been disclosed, for example, in the Dow Jones broad tape; news wire services such as AP or Reuters; radio or television; newspapers or magazines; the OASIS; or widely circulated public disclosure documents filed with the SEC, such as prospectuses or proxies.

Although it is natural to "talk shop," no Confidential Information should be given to outsiders; for this purpose, outsiders include one's Immediate Family, relatives, friends and anyone else other than those working on the matter at the NERTO. In general, NERTO matters should not be discussed with any outside individuals. Particular care is necessary in discussing NERTO matters in elevators, restaurants, taxicabs, trains, commercial aircraft and other public places where names and other scraps of information might be overhead. Care should also be taken not to expose nonpublic papers in such places or leave them lying around in conference rooms or other places, even within the NERTO.

5.2 Penalties for Trading on Insider Information

It is against NERTO policy and a violation of law to make use of insider information for personal advantage in securities trading or to disclose such information to an outsider. NERTO Employees who have any knowledge of insider trading activities or improper disclosure committed by other NERTO Employees must notify the NERTO Compliance Officer or his designee immediately. NERTO Employees who have engaged in insider trading or have provided insider information to outsiders will be terminated immediately. In addition, both the NERTO and the NERTO Employee may be subject to severe civil and criminal penalties as a result of insider trading by the NERTO Employee or by an outsider who has received insider information from the NERTO Employee.

6. TRAINING

The NERTO shall develop procedures to train NERTO Employees on the Code of Conduct and to assess the effectiveness of the Code of Conduct in preventing insider trading and conflicts of interest. All NERTO Employees will receive annual training for as long as they remain associated with the NERTO. The attendance of all NERTO Employees at the annual training sessions is mandatory. All personnel attending such training sessions shall sign a

Compliance Certificate stating that they attended the training, understand the Code of Conduct, and will not violate it. In addition, the NERTO Compliance Officer or his designee will maintain a log of all training sessions held along with their respective dates, topics addressed and attendees at each session. The NERTO Compliance Officer or his designee will be required to keep records of executed certifications to ensure that all NERTO Employees complete and execute such certifications annually.

7. NERTO RECORDS

The NERTO shall develop and maintain procedures for the handling, safeguarding, using, storing and retaining of NERTO Records. The NERTO requires all NERTO Records to be accurate. The NERTO will make such NERTO Records available to Market Participants and the general public to the extent technically feasible and permitted by Section 4 through posting on the NERTO's website.

8. VIOLATIONS OF THE CODE OF CONDUCT

Any NERTO Employee who violates the Code of Conduct or fails to report a known violation may be subject to disciplinary action including suspension or termination of employment, unless such violation involves insider trading, in which case such violation will result in the termination of employment. In addition, any current or former NERTO Employee who willfully and knowingly violates the Code of Conduct may be required to provide restitution to the NERTO for financial injury suffered by the NERTO as a result of the violation.

The NERTO Compliance Officer shall have the responsibility for reviewing compliance with the Code of Conduct, including: interpreting the Code of Conduct; advising NERTO Employees regarding potential conflicts of interest; overseeing the auditing process; and following up on all suspected violations. The NERTO shall also establish a "hot-line" to provide a means for anonymously and confidentially reporting suspected violations over the telephone.

9. WAIVER

The Audit and Finance Committee of the NERTO Board may grant a waiver of compliance from a specific provision of the Code of Conduct to a member of the NERTO's Board of Directors, or the NERTO Compliance Officer or his designee may grant a waiver of compliance to all other NERTO Employees, as appropriate to avoid unjust or unreasonable results. In granting any such waiver, the Audit and Finance Committee or NERTO Compliance Officer or his designee may consider appropriate limitations on the duties of the NERTO Employee to avoid a conflict of interest.

Annual Compliance Certificate

I have received the Code of Conduct which I have read, been trained in, and fully understand. I will comply with the Code of Conduct during and, to the extent required by the Code of Conduct, after association with the NERTO.

I am ( ) a Director ( ) an Officer ( ) an NERTO Employee.

a. I have no Prohibited Financial Interests other than those that, in accordance with the NERTO's divestiture policy, I still have time to divest, or for which I have been granted a hardship exception.

b. I have no other financial or business relationship with a Market Participant that would create a conflict of interest as defined in the Code of Conduct (or if I do, I have been granted a waiver by the Audit and Finance Committee or the NERTO Compliance Officer or his designee).

c. Since I last signed a Compliance Certificate, I have complied with the rules and policies contained in the Code of Conduct, except for the following matters which I disclose to the Board of Directors of the NERTO (if none, so state):

____

____

Signature: ______________________ Date: ____________________________

Name (print): ___________________ Title/Position: _____________________

ATTACHMENT VI

NERTO Interconnection Process

I) Interconnection of a Generating Unit, Merchant Transmission, or any other System Upgrade Facility (i.e., the Interconnecting Project) Under the Minimum Interconnection Standard: Any Interconnecting Project ("IP") Owner (the "Owner") that proposes: (i) to place in service a new IP at a site(s) which the Owner owns or controls, or which it has the right to acquire or control, and that will interconnect to the NERTO Transmission System, or (ii) to materially change and increase the capacity of an existing facility located in the NERTO region shall be obligated to:

(a) Complete and submit to NERTO a standard application and description of its proposal and site(s) information required by the Interconnection Application, as well as any additional information that may be reasonably required by the NERTO;

(b) Enter into an agreement with NERTO for the conduct or review of a System Impact Study (SIS)[1] to determine what additions or modifications to the NERTO Transmission System are necessary in order to permit its IP to interconnect in a manner that avoids any significant adverse effect on system reliability, stability, and operability, including protecting against the degradation of transfer capability affected by the IP that remains after re-dispatch under

[1] Also known in New York as the "System Reliability Impact Study" or "SRIS".

system conditions as currently specified in the NEPOOL OATT (i.e., the "Minimum Interconnection Standard").

In conjunction with an IP, an Owner may request an Elective Transmission Upgrade in accordance with the NERTO Tariff.

II) Prioritization of Studies: For purpose of determining priority for conducting or reviewing a SIS for an IP, NERTO shall give priority to each interconnection proposal on the basis of its date of submittal to the NERTO. During the initial transition period following the start of NERTO operations, the existing study queues of both the NYISO and ISO-NE (if any) shall be merged according to the original date of submittal to the respective ISO.

III) SIS Procedure: The SIS will be performed to evaluate the impact of the requested service on the reliability and operating characteristics of the bulk power system, consistent with:

(a) Good utility practice
(b) NERC standards, guides, and procedures;
(c) NPCC criteria and guidelines;
(d) New England criteria, rules, procedures, and reliability standards;
(e) New York State Reliability Council criteria, rules, procedures, and reliability standards;
(f) Applicable requirements of the NERTO Tariff;

(g) Applicable guides, standards, and criteria of the impacted Transmission Owner(s), as accepted by NERTO;

(h) Other applicable guidelines and standards that may need to be incorporated by NERTO from time to time.

As such, the study will examine the impact on the NERTO regional power system and its component systems and neighboring and external systems. Consistent with the aforementioned, the ability to operate the system subject to the following will be considered:

(a) All equipment within its applicable capabilities;

(b) Voltages and reactive reserves within acceptable levels;

(c) Stability maintained with adequate levels of damping;

(d) Frequency (Hz) within acceptable levels.

The study will consider the reliability requirements to meet existing and pending obligations of the Market Participants and the obligations of the impacted Transmission Owner(s).

The study will be performed using appropriate and suitable analysis tools and modeling data consistent with the nature and duration of the requested service. It is expected that the Owner will provide the prescribed information and such other information as may be reasonably required and associated with the requested service and necessary for its study. It is also recognized that it may be determined that additional or specialized analysis tools or computer software are necessary for the study. The responsibility for the provision of these items will be subject to the study agreement.

The study will identify if the requested service can be provided without adverse impact on the reliability and operating characteristics of the system. The study will also identify if it appears that modification of the system is necessary to provide the service.

IV) Cost Allocation Procedure: IPs will be responsible for the cost of their Attachment Facilities, as defined in subsection (b) below. An IP's share of System Upgrade Facilities ("SUF"), as defined in subsection (b) below, or "but for" cost will be determined in the "class year study". The class year study will be conducted annually in conjunction with the development of the NERTO System Plan ("NSP"). To be included in the class year study or to be reflected in the NSP baseline, an IP will have had its SIS completed and approved by NERTO and have met the appropriate state or local regulatory milestones or the equivalent as established by NERTO in consultation with the PAC (e.g., an accepted milestone in a State's siting process) by March 1 of each year. The determination of each IP's share of a SUF will be as follows:

Summary Description of the Process

(a) Purpose

This procedure allocates to each IP its responsibility for the cost of the net impact of the project on the reliability of the transmission system. Thus, a project is held responsible for the cost of the interconnection facilities that are required by, or caused by, the project; the facilities that would not be needed "but for" the project. A project is not responsible for the cost of facilities that are required anyway, without the construction of the project, to maintain transmission system reliability. The cost of these "anyway" facilities is borne by the Transmission Owner. If an IP reduces the need for facilities that would be required anyway, the process recognizes the benefits of the resulting cost reduction impact. The net cost and cost reduction impact of an IP is determined by studies that are conducted by NERTO.

(b) The Interconnection Standard

The cost allocated by this Process is the cost of the facilities needed for an IP to interconnect reliably to the transmission system in compliance with the Minimum Interconnection Standard described in Section I, Part b above. The NERTO Minimum Interconnection Standard is designed to ensure reliable access by the proposed IP to the NERTO Transmission

System. A request for an interconnection under the NERTO Minimum Interconnection Standard is separate from a request for transmission service. Consequently, this Process does not address the allocation of responsibility for the cost of new facilities to meet such request for transmission service.

(c) Cost Allocation of Interconnection Facilities

The interconnection facilities covered by this Process are comprised of two types, Attachment Facilities and SUF. Attachment Facilities are facilities that are constructed for the sole benefit of the IP, to physically attach that project to the existing NERTO Transmission System. Each IP is responsible for 100% of the cost of the Attachment Facilities for its project.

SUF are the modifications to the existing NERTO Transmission System that are required to maintain system reliability in response to changes in the system, including such changes as load growth, changes in load patterns, and proposed new IPs. In the case of proposed new IPs, SUF are the modifications or additions to the existing NERTO Transmission System that are required for the IP to reliably interconnect to the system in a manner that meets the NERTO Minimum Interconnection Standard. As explained in greater detail below, the cost of SUF is first allocated between IPs and Transmission Owners, and then the IPs' share of the cost is allocated between each individual IP.

The cost of SUF is allocated between IPs and Transmission Owners based upon the results of an Annual Transmission Baseline Assessment ("ATBA") that identifies the need for SUF in the absence of any of the class year IPs . The purpose of the ATBA is to identify the SUF that each Transmission Owner needs to install to reliably meet load growth and changes in load patterns. The ATBA is conducted annually by NERTO in conjunction with Transmission Owners as part of the NSP .

IPs are not responsible for the cost of any SUF that are identified in the ATBA, or any SUF that resolve in whole or in part a deficiency in the system identified in the ATBA. However, IPs are responsible for the cost of SUF, not already identified in the ATBA, that are needed because of their projects. The individual SIS done for each of the IPs first identifies the SUF needed because of the IPs, and then confirmed by the annual NSP.

An IP's share of the cost of SUF is allocated between IPs and Transmission Owners by netting the total costs resulting from the SUF required for ATBA vs. the NSP that includes the class year IPs. The IP's share is then allocated among individual IPs, based upon the results of the NSP.

No IP is responsible for any of the cost of any individual SUF if his project does not have at least a de minimis impact on the reliability of the Transmission System; that is, if the IP does not make a material contribution to the need for that SUF. De minimis thresholds are defined in technical terms, as specified in Attachment S of the NYISO OATT. Based on the NSP, each included IP will be given a dollar figure and supporting information for its share of the cost of the minimum amount of SUF required for reliable interconnection of the IP to the NERTO Transmission System.

The congestion costs that may include redispatch and unit commitment costs incurred during the construction of the direct attachment facilities and SUFs will be part of the ongoing cost-of-doing business for the market. Recurring operations and maintenance (O&M) cost of direct attachment facilities will be the responsibility of the IP. Recurring O&M cost of SUFs that are generally considered network facilities will be the responsibility of the owner of such facilities.

V) Facilities Studies and Interconnection Agreements: Upon acceptance of the cost responsibilities determined through cost allocation process described above, the IP will enter into a facilities study ("FS") agreement that will provide the detailed design, engineering and final cost estimates for the direct attachment facilities and any system upgrade facilities. The IP enters into the appropriate interconnection agreements ("IA") with the interconnecting Transmission Owner(s) simultaneously with the conduct of the

FS or at the completion of the FS. The purpose of the IA is to establish and provide the security, credit assurances and/or deposits that the Transmission Owner determines are necessary to ensure payment for direct attachment facilities and SUFs.

VI) Transition Process: At the time of the commencement of NERTO operations, any IP in New England (NE) or New York (NY) which has an accepted interconnection application pending in the respective ISOs must complete the Interconnection Process[2] under the existing criteria (e.g., the interconnection standard or SIS) and rules (e.g., cost allocation rules) that are in effect in NE and NY prior to the effective date of the NERTO. Applications excepted on or after the effective date of the NERTO will be subject to the NERTO criteria and rules as defined above.

Transition Period: If the effective date of the NERTO occurs on or before March 1 in any given year, the pending interconnection applications in NE and NY will have until the second March 1 of the date following commencement of NERTO operations to complete its interconnection process under the criteria and rules in affect in NE and NY.

If the effective date of the NERTO occurs after March 1 of any given year, the pending interconnection applications in NE and NY will have twelve months from the date following commencement of NERTO operations to complete its interconnection process under the criteria and rules in affect in NE and NY.

[2] The interconnection process is defined as complete upon approval of the SIS in NE (i.e., an approved 18.4 Application) and upon acceptance into the "class year study" in NY.

After the transition period, all units will be subject to the NERTO criteria and rules.

ATTACHMENT VII

NERTO Planning and Expansion Process

NOTE: SEE ATTACHED PROCESS FLOW CHART

1. General:

The process defined in this document shall be utilized for regional planning in NERTO. The NERTO System Plan (the “Plan”), including the related transmission enhancement and expansion studies, shall be completed by NERTO. In completing the Plan, NERTO shall consult with the Planning Advisory Committee. The Planning Advisory Committee shall be established in accordance with the provisions of Section 2.1, and shall be responsible for the functions identified in that Section.

2. Establishment of Planning Advisory Committee:

2.1. A Planning Advisory Committee shall be established to perform the functions set forth in Section 2.2 below. It shall have a Chair and Secretary, who shall be appointed by the chief executive officer of NERTO. Before appointing an individual to the position of the Chair or Secretary, NERTO shall notify the Committee of the proposed assignment and, consistent with its personnel practices, provide any other information about the individual reasonably requested by the Committee. The chief executive officer of NERTO shall consider the input of the members of the Committee in selecting, removing or replacing such officers. The Planning Advisory Committee shall be advisory only and shall have no formal voting protocol. [conform to overall stakeholder advisory committee procedures when completed to provide meaningful input]

2.2. The Planning Advisory Committee may provide input and feedback to the NERTO concerning the development of the NERTO System Plan and the conduct of system enhancement and expansion studies, including the facilitation of the needs assessment and responding to NERTO's request for solutions. Any entity (including state agencies) may designate a member to the Planning Advisory Committee by providing written notice to the Secretary of that Committee identifying the name of the entity represented by the member and the member's name, address, telephone number, facsimile number and electronic mail address. The entity may remove or replace such member at any time by written notice to the Secretary of the Planning Advisory Committee.

3. NERTO System Plan; Principles, Scope, and Contents:

3.1. The NERTO System Plan provides an annual assessment of the system needs of the NERTO Control Areas in a consolidated manner, and is designed to maintain the NERTO Control Areas' reliability while accounting for economic and environmental considerations. At least every three years, the NERTO System Plan shall reflect the results of a new comprehensive system planning and expansion study conducted pursuant to Section 5. In other years, the NERTO System Plan may be only an update to a prior approved Plan. Comprehensive system enhancement and expansion studies include a needs assessment by NERTO (as described in Section 5.5), and NERTO analysis of the market and transmission solutions offered in response thereto (as described in Section 5.6).

3.2. The baseline for the NERTO System Plan shall account for: (i) all projects that have met milestones (such as the determination of the absence of "significant adverse impact" under the NE Section 18.4 process or siting approvals) determined by NERTO in collaboration with the Planning Advisory Committee, including but not limited to proposed generation and transmission projects, Merchant Transmission Facilities, and Elective Transmission Upgrades; (ii) demand-side projects planned within the NERTO Control Areas and identified to NERTO; and (iii) the requirements for system restoration services. The development of the NERTO System Plan will not include development of a system restoration plan.

3.3. The NERTO System Plan shall utilize a ten-year planning horizon, and reflect a ten-year capacity and load forecast The NERTO System Plan shall identify, based on the results of system enhancement and expansion studies conducted pursuant to Section 5, a list of proposed Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades to the NERTO Transmission System for at least each of the ensuing five years, not otherwise proposed as Merchant Transmission Facilities or Elective Transmission Upgrades, that are determined by NERTO to be appropriate at the time of the issuance of the Plan (collectively referred to as “Transmission Upgrades”). Each NERTO System Plan shall also include the list of Transmission Upgrades included in any prior Plans (including prior New England Regional Transmission Expansion Plans and those included in New York’s Annual Transmission Reliability Assessment), as updated, that have not been completed at that time. The lists of Transmission Upgrades shall identify separately (i) Reliability Transmission Upgrades, and (ii) Market Efficiency Transmission Upgrades. The Plan shall also list transmission facilities (as determined under the NERTO Interconnection Process) to be built to accommodate new generation, merchant transmission, and elective transmission interconnections that have satisfied the requirements of the Tariff. The Plan shall also include a description of the reasons for any new Transmission

Upgrades proposed in the Plan, or for any removal of Transmission Upgrades from the Plan pursuant to Section 3.4 below.

3.4. A Transmission Upgrade may be added to the NERTO System Plan by NERTO at any time in a given year and in doing so NERTO shall consult with and consider input from the Planning Advisory Committee, within the scope of its respective functions as specified in Section 2. Similarly, a Transmission Upgrade may be removed from the NERTO System Plan by the NERTO if the market responds by developing credible alternative generation projects, Merchant Transmission Facilities in accordance with Section 8, or demand-side projects, or other circumstances arise such that the need for the Transmission Upgrade no longer exists, and in doing so NERTO shall consult with and consider input from the Planning Advisory Committee, within the scope of its functions as specified in Section 2; provided that (if the Transmission Upgrade is removed from the plan by NERTO) the entity responsible for the construction of the Transmission Upgrade is reimbursed for any costs (plus a reasonable return on investment at existing FERC-approved ROE levels) prudently incurred or prudently committed to be incurred in connection with the planning, designing, engineering, permitting, procuring and other preparation for construction, and/or construction of the Transmission Upgrades proposed for removal from the Plan. For Reliability Transmission Upgrades, the allocation specified in Exhibit 1 hereto shall apply to this cost reimbursement. For Market Efficiency Transmission Upgrades and for projects resulting from a Request for Alternative Proposals (as described in Section 4.4 below), the allocation specified in the approved funding allocation shall apply to this cost reimbursement.

3.5. The NERTO System Plan shall conform to: Good Utility Practice; applicable reliability principles, guidelines, criteria, rules, procedures and standards of NERC, NPCC, NYSRC and any of their successors; NERTO-approved Transmission Owner criteria, rules, standards, guides and policies; and the NERTO System Rules, as they may be amended from time to time.

3.6. The NERTO System Plan shall be designed (i) to avoid unnecessary duplication of facilities; (ii) to avoid the imposition of unreasonable costs upon any Transmission Owner, Transmission Customer or other user of a transmission facility; (iii) to take into account the legal and contractual rights and obligations of the Transmission Owners and the transmission-related legal and contractual rights and obligations of any other entity; (iv) to provide for coordination with existing transmission systems and with appropriate interregional and local expansion plans; (v) to properly coordinate with market responses, including generation, merchant transmission and demand-side responses.

4. Procedures for Developing a NERTO System Plan

4.1. At the initiation of an effort to update a Plan or develop a new Plan, NERTO shall solicit input on regional needs for the updated or new Plan from members of the Planning Advisory Committee. The Planning Advisory Committee shall meet to perform its respective functions in connection with the preparation of the NERTO System Plan, as specified in Section 2.1. Thereafter, drafts of the NERTO System Plan shall be provided to the Planning Advisory Committee and input from that Committee shall be received and considered in preparing and revising subsequent drafts.

4.2. The Transmission Owners, those entities requesting transmission service or interconnection, and any other entities proposing to provide facilities to be integrated into the NERTO Control Areas or alternatives to such facilities shall supply upon request and subject to applicable confidentiality requirements of the [NERTO Information Policy/Code of Conduct] any information and data reasonably required to prepare a NERTO System Plan or to perform a transmission enhancement and expansion study. Any confidential cost estimate for a proposed Transmission Upgrade to the NERTO Transmission System that is or may be subject to Section 6 shall be considered by NERTO to be competitively sensitive, confidential information and shall be considered the estimator's confidential information, and shall not be disclosed by NERTO to other entities that may be eligible to submit a proposal in accordance with Section 6, including, without limitation, other Transmission Owners. Any other information or data provided shall be subject to the rights and obligations of the NERTO [Information Policy/Code of Conduct].

4.3. A draft of a recommended NERTO System Plan shall be presented at least annually by the NERTO staff to the NERTO Board of Directors for approval. The draft NERTO System Plan shall incorporate the results of any expansion and enhancement studies performed since the last Plan was approved. Before a final draft of any recommended NERTO System Plan is presented to the NERTO 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. The final draft of the recommended NERTO System Plan shall be presented to the NERTO Board of Directors no later than [month and day] of each year and shall be acted on by the Board within __ days of receipt.

4.4. The NERTO Board of Directors may approve the recommended Plan as submitted, modify the Plan or remand all or any portion of it back with guidance for development of a revised recommendation in accordance with this Section 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 Board reflecting the public meeting held pursuant to this Section 4.3. In considering whether to include a particular Market Efficiency Transmission Upgrade in the approved Plan, the Board of Directors shall consider the relative severity of the congestion addressed by that Market Efficiency Transmission Upgrade. If the Board of Directors determines to include an Market Efficiency Transmission Upgrade in the approved Plan, it shall consider the funding mechanism in Exhibit 1 as well as any other funding mechanisms recommended by the NERTO staff with input from the Planning Advisory Committee, subject to Commission and/or state regulatory approval. In considering whether to approve the recommended Plan, the Board of Directors may, if it finds a proposed Market Efficiency Transmission Upgrade or Reliability Transmission Upgrade not to be viable from a timeliness or financial standpoint, or if no Transmission Upgrade has been proposed, direct the NERTO staff to issue a Request for Alternative Proposals ("RFAP") as described below, and withhold approval of the Plan, or portions of the Plan, pending the results of that RFAP. The RFAP shall seek generation, demand-side and merchant transmission alternatives, and normally will focus on interim ("gap") solutions. The NERTO staff shall provide the Board of Directors and Planning Advisory Committee with an analysis of the alternatives offered in response to the RFAP, and provide a recommendation together with a funding mechanism reflecting input from the Planning Advisory Committee. The Board of Directors may determine to include one of the alternatives in the approved Plan.

4.5. **Interregional Coordination**: The NERTO System Plan shall be developed in coordination with the similar plans of the surrounding RTOs and Control Areas. Interregional planning studies shall be conducted over as broad a region as feasible, including adjacent Canadian systems who are members of NPCC, MAAC and ECAR.

4.6. **Cost Allocation:** The cost responsibility for each Reliability Transmission Upgrade that is listed in the NERTO System Plan shall be determined in accordance with Exhibit 1 hereto.

5. Procedures for the Conduct of System Enhancement and Expansion Studies:

5.1. System enhancement and expansion studies shall be conducted in accordance with the procedures set forth in this Section 5. The results of these studies shall be reflected in the NERTO System Plan.

5.2. NERTO shall initiate system enhancement and expansion studies at least once every three years. A more targeted study shall be conducted if: (i) a need for additional transfer capability is identified by NERTO in its evaluation of requests for firm transmission service with a term of one year or more or as a result of NERTO’s ongoing evaluation of the bulk power supply system’s adequacy and performance; (ii) a need for additional transfer capability is identified as a result of the NERC and/or NPCC reliability assessment or more stringent publicly available local reliability criteria, if any; or (iii) constraints or available transfer capability limitations are identified as a result of generation additions or retirements, evaluation of load forecasts or proposals for the addition of transmission facilities in the NERTO Control Areas. A system enhancement and expansion study may also be initiated for any other circumstances which may warrant such a study.

5.3. Written notice of the initiation of a system enhancement and expansion study shall be provided to all members of the Planning Advisory Committee. That notice shall identify the needs supporting the initiation of the study.

5.4. NERTO shall prepare a needs assessment that examines resource adequacy, transmission adequacy, and projected congestion levels, and that considers the views, if any, of state regulators, the Market Advisor to the NERTO Board of Directors, and the NERTO Board of Directors. Meetings of the Planning Advisory Committee shall be convened to identify additional considerations relating to such a system enhancement and expansion study that were not identified in support of initiating the study, and to provide input on the study's scope, assumptions and procedures, consistent with the responsibilities of the Planning Advisory Committee as set forth in Section 2. The needs assessment will identify situations that significantly affect the efficient operation of the NERTO bulk power system, and any critical time constraints for addressing reliability needs. The criteria for determining which market efficiency needs shall be included in the completed needs assessment, and for assessing the cost-effectiveness of solutions proposed in response thereto, will be developed by NERTO with input from the Planning Advisory Committee. A subcommittee of the NERTO Board of Directors will convene a public meeting to review the proposed needs assessment.

5.5. NERTO shall publish the completed needs assessment on its website, including both reliability needs as well as projected congestion levels under various conditions, and issue a final report serving as a Request for Solutions for responses that can meet the needs described in the assessment. A period of __ days is provided for market participants and transmission owners and developers to provide solutions, which, for example, may be in the form of new transmission facilities (either by a Transmission Owner or a merchant transmission developer), generation (conventional, distributed or renewables), or demand response and conservation programs. It is expected that, whatever the market response, the affected Transmission Owner(s) will provide a regulated transmission proposal(s) in response to NERTO's needs assessment for all identified needs within the timeframe specified above.

5.6. Upon receipt of the responses to the Request for Solutions, the NERTO shall (with input from the Planning Advisory Committee) evaluate such responses to determine whether, and to what extent, any such proposals will meet the identified needs. The evaluation shall be premised on the goals of maintaining reliability and reducing congestion where economically justified under the criteria developed in accordance with Section 5.4 above. If the market response (including merchant transmission) is determined by NERTO to be sufficient to alleviate the need for a particular Transmission Upgrade, and is judged to be achievable within the required time period, the NERTO will reflect this finding (without selecting a particular market proposal) in its recommended NERTO

System Plan to be submitted to the NERTO Board for approval, and that particular additional Transmission Upgrades will be listed in the recommended NERTO System Plan subject to NERTO having the flexibility to indicate that the project should proceed at a later date. If the market response (including merchant transmission) is determined by NERTO to be insufficient to alleviate the need for a Transmission Upgrade, that Transmission Upgrade will be listed in the recommended Plan (assuming that it is considered viable from both a timeliness and a financial standpoint) with an indication to begin development in accordance with Section 3.3, together with the information required therein.

5.7. The results of the system enhancement and expansion study(ies), along with a discussion of the study assumptions and input(s), shall be made public and shall be included as part of the next annual NERTO System Plan in accordance with Sections 3 and 4.

6. Request for Proposals ("RFP") Process For Construction of Transmission Upgrades:

6.1. Siting approval for a Transmission Upgrade is the responsibility of the Project Sponsor. Except as otherwise provided in Section 6.8 below, once siting approval has been obtained by the Transmission Owner, NERTO shall develop and post on its website a request for proposals ("RFP") inviting any entity or entities, including without limitation Transmission Owners, to construct a Transmission Upgrade included in the NERTO System Plan. The RFP is for construction, and not ownership, of the Transmission Upgrade. If the Transmission Owner that will own the completed facilities (the "Project Sponsor") does not plan to submit a proposal in response to the RFP, it shall develop (in coordination with NERTO) and propose the RFP for NERTO approval. If the Project Sponsor plans to submit a proposal in response to the RFP, the RFP shall be prepared by NERTO, which shall consult with the Transmission Owner(s) to obtain necessary data, information and technical specifications that NERTO finds necessary to prepare the RFP. The RFP shall include appropriate requirements to safeguard the confidential nature of information provided to NERTO in accordance with applicable commercial practices, the requirements of the NERTO [Information Policy/Code of Conduct] and the requirements of any applicable Commission order. Each such RFP shall require that respondents meet specified technical and financial qualifications and submit proposals: (i) that conform with all the requirements of Section 3.1 and reasonable Transmission Owner requirements and specifications identified in the RFP which are not inconsistent with Commission policy, (ii) that are consistent with other applicable accepted engineering practices, governmental, technical, and financial requirements.

6.2. The RFP shall include, at a minimum: (i) a proposed construction contract; (ii) required technical and financial qualifications, including measure of the ability to implement the proposed project; and (iii) acceptable engineering practices, and governmental, technical, and financial requirements. Each shall be consistent with the technical specifications provided by the Project Sponsor and approved by NERTO.

6.3. NERTO shall develop generic selection criteria and in doing so shall consult with the Planning Advisory Committee and post the criteria on NERTO's website prior to issuance of the RFP. If the Project Sponsor does not plan to submit a proposal, NERTO shall consult with the Project Sponsor before issuing an RFP to determine if any specific selection criteria are required; NERTO shall include all reasonable selection criteria requested by the Project Sponsor. The evaluation criteria may consider any or all of the following nonexclusive factors: (i) the qualifications of the entity that would be responsible for implementing the proposal to build the proposed Transmission Upgrade; (ii) the estimated financial and reliability impacts on Transmission Customers and load during and after construction and installation of the proposed Transmission Upgrade if the proposal is accepted and implemented; (iii) the timing for completion of the proposal; (iv) the assurance that the entity responsible for implementing the proposal is able to perform; and (v) the mobilization or demobilization of facilities affected by the building of the proposed Transmission Upgrade during construction and installation.

6.4. The selection process shall be conducted as follows. (i) Where the Project Sponsor is not a bidder, the Project Sponsor selects the successful bidder. The Project Sponsor and the successful bidder execute a construction contract, and the Project Sponsor manages the construction project. NERTO approves major change orders. (ii) Where the Project Sponsor is a bidder, NERTO selects the successful bidder, and, if the Project Sponsor is the successful bidder, NERTO may arrange for third-party review of construction performance. If the successful bidder is not the Project Sponsor, the Project Sponsor shall proceed as in (i) above.

6.5. The issuance of an RFP for a Transmission Upgrade shall not preclude the modification of a NERTO System Plan in accordance with Section 3.4, including, without limitation, a modification that eliminates such Transmission Upgrade from the recommended plan.

6.6. Any entity whose proposal is accepted by NERTO in accordance with Section 6.4 shall be compensated in accordance with the terms of its accepted proposal, without regard to whether the actual project cost for the Transmission Upgrade was less than or greater than the costs reflected in the accepted proposal.

6.7. NERTO will post the following initial exemptions from the RFP requirements of this Section: (a) Transmission Upgrades costing under $20 million; (b) Transmission Upgrades that constitute general maintenance or replacements of existing equipment; (c) Transmission Upgrades with an expected construction period of less than nine months; and (d) facilities associated with interconnections for generation, Elective Transmission Upgrades, or Merchant Transmission Facilities, and with requests for transmission service under the NERTO Tariff. NERTO, in its discretion and after receiving input from the Planning Advisory Committee, may expand or supplement these initial exemptions and exempt other Transmission Upgrades from the RFP requirements of this Section 6, and post the additional or amended exemptions on the NERTO website. Where a Reliability Transmission Upgrade is exempt, the Transmission Owner or Owners on whose system(s) the proposed Reliability Transmission Upgrade in the Plan is located, or its/their designee(s), shall be designated as the appropriate entity responsible for completion of that Reliability Transmission Upgrade, in accordance with the requirements of Section 7.

6.8. No proposed Merchant Transmission Facility shall be the subject of the RFP process of this Section 6. No provision of this Regional Planning Process affects any obligations to interconnect new customers to the NERTO Transmission System imposed by other provisions of this Tariff or the Federal Power Act.

7. Obligations of Transmission Owners to Build:

7.1. Subject to the requirements of applicable law, government regulations and approvals, including, without limitation, requirements to obtain any necessary state or local siting, construction and operating permits, to the availability of required financing, to the ability to acquire necessary right-of-way, and to the right to recover, pursuant to appropriate financial arrangements and tariffs or contracts approved or accepted by those regulatory agencies with jurisdiction, all reasonably incurred costs, plus a reasonable return on investment, Transmission Owners designated by NERTO as the appropriate entities to construct and own or finance Transmission Upgrades included in the Plan shall construct and own or finance such facilities or enter into appropriate contracts to fulfill such obligations.

7.2. The costs of any Reliability Transmission Upgrades constructed pursuant to the provisions of Section 7.1 shall be allocated as specified in Exhibit 1 hereto.

8. Merchant Transmission Facilities; Compliance:

8.1. Subject to compliance with the requirements of the Tariff and any other applicable requirements with respect to the interconnection of bulk power facilities with the NERTO Transmission System, any entity shall have the right to propose and construct the addition of transmission facilities outside the Plan, none of the costs of which shall be covered under the cost allocation provisions of the Tariff ("Merchant Transmission Facilities"). Any such Merchant Transmission Facilities shall be subject to the requirements of Section 8.2 below.

In performing studies in connection with the NERTO System Plan, the prospect that proposed Merchant Transmission Facilities will be completed shall be accounted for on the same basis as the prospect that proposed generating units will be completed.

8.2. All Merchant Transmission Facilities shall be subject to: (i) an agreement (complying with the requirements of the Tariff) to transfer to NERTO operational control authority over any facilities which constitute part of the Merchant Transmission Facilities that are to be integrated with, or that will affect, the NERTO Transmission System; and (ii) taking such other action as may be required to make the facility available for use as part of the NERTO Transmission System.

9. Alternative Remedies:

Nothing herein shall limit in any way the right of any entity to seek any available relief pursuant to the provisions of the Federal Power Act.

10. Definitions:

10.1. Generator Interconnection Related Upgrade: An addition to or modification of the NERTO Transmission System (as determined pursuant to the NERTO Interconnection Process) to effect the interconnection of a new generating unit or an existing generating unit whose capacity is being materially changed and increased.

10.2. NERTO System Plan: A plan for the expansion or modification of the NERTO Transmission System which has been developed pursuant to Sections 1 through 7 hereof.

10.3. Reliability Transmission Upgrade: Those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the NERTO 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. In evaluating proposed Reliability Transmission Upgrades, the following will be used to define the system facilities required to maintain reliability: applicable principles, guidelines, criteria, rules, procedures and standards of NERC, NPCC, NYSRC, and any of their successors; the NERTO System Rules, as they may be amended from time to time; and NERTO-approved Transmission Owner criteria, rules, standards, guides, and policies.

10.4. Market Efficiency Transmission Upgrade: Those additions and upgrades that do not qualify as Reliability Transmission Upgrades, are not related to the interconnection of a generator, and are designed to improve the efficiency of the markets by, for example, reducing congestion in load pockets and relieving "bottled generation."

10.5. Regional Transmission Facilities ("RTF"): The transmission facilities subject to NERTO's operational control.

10.6. Elective Transmission Upgrade: An addition to or modification of the NERTO Transmission System that is not: (i) a Generator Interconnection Related

Upgrade; (ii) a Reliability Transmission Upgrade; (iii) an Market Efficiency Transmission Upgrade; or (iv) otherwise identified in the current NERTO Transmission Plan in publication as of the date an Elective Transmission Upgrade Application is filed with NERTO in accordance with the NERTO Tariff. An Elective Transmission Upgrade may increase transfer capability of the NERTO Transmission System, may increase the reliability or stability of the NERTO Transmission System above the requirements and criteria established by NERC, NPCC, NYSRC, or NERTO System Rules or may reduce Congestion Costs into or within the NERTO Control Areas.

Exhibit 1

Allocation of Costs of Reliability Transmission Upgrades Included in NERTO System Plan

These cost allocation principles apply to Reliability Transmission Upgrades of Regional Transmission Facilities ("RTF"), the assets subject to the NERTO planning process:

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

II. In the absence of such agreement,[*]

A. Costs of 345 kv facilities and above (other than transformers) that contribute to the parallel carrying capability of the NERTO Transmission System shall be charged to NERTO load;

B. Costs of facilities below 345 kv (other than transformers) shall be charged to the load in the sub-region (i.e., either New York or New England) in which the facilities are built, in accordance with existing practices; and

C. One-half of the costs of transformers shall be allocated in accordance with the methodology specified in II.A. or B. above, based upon the voltage at the high side of the transformer and one-half of the costs shall be allocated in accordance with the methodology specified in II.A. or B. above, based upon the voltage at the low side of the transformer.

The preceding default allocation method shall be reevaluated in light of final rules issued subsequently by the FERC.

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[*] The allocation of the costs for other technologies, such as HVDC and FACTS, shall be developed on a cas-by-case basis.

NSP Process Flow

SEES Needs Assessment

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Inform Participants

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Request for Solutions in Consultation with PAC — NERTO BOD Public Meeting

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Market Responses
- Generation
- DSM
- Merchant Transmission

Regulated Transmission
- Proposals

↓

NERTO Evaluates Market Responses and Transmission with PAC Input

↓

NERTO Formulates NSP to Maintain System Reliability and Economically Justify Congestion Reduction

↓ NERTO BOD Public Meeting

Board Approval of NSP

↓

RFP for Transmission Construction

↓ No viable/timely mkt or tx solution to an identified need

RFAP (primarily for gap)

↓

Board Approval of NSP

Revised 6/5/02

ATTACHMENT VIII

NORTHEASTERN REGIONAL TRANSMISSION ORGANIZATION
IMPLEMENTATION PLAN SUMMARY

The Northeast Regional Transmission Organization ("NERTO") created by the combination of ISO New England Inc. ("ISO-NE") and the New York Independent System Operator, Inc. ("NYISO") (together the "ISOs") will be consistent with the Commission's SMD principles. When implemented, the NERTO will operate a seamless energy market that spans the entire Northeastern region of the United States. The NERTO will also be closely integrated with the Canadian energy markets to the North and almost seamlessly connected to the energy markets administered by the PJM Interconnection to the South.

Upon approval by the Commission, the NERTO will serve approximately 33 million people and will operate a market-based system comprised of 64,000 megawatts of generating capacity, 18,000 miles of transmission, and approximately $7 billion of annual NERTO-administered settlements. The implementation of an RTO of this size and scope will require a significant effort over several years.

The information presented in this Attachment is a summary of the initial version of the implementation plan for establishing a single regional power market in the Northeast ("Implementation Plan"). The Implementation Plan has been developed jointly by the ISOs. It builds upon the "Option 1-M" market development and implementation approach developed during the Commission's mediation process for a Northeast RTO, which Administrative Law Judge Peter Young encouraged the Commission to endorse as the appropriate starting point for implementation of a Northeast market in his mediation report. The Implementation Plan has been developed using a phased approach to enable the NERTO to realize regional market benefits from the elimination of seams and export fees prior to the implementation of a single dispatch and common settlement system.

The Implementation Plan for the NERTO, described in this document, is conservative. It is the product of input from key personnel in each major functional area of the ISOs, resulting in a realistic approach to this task. The Implementation Plan has been developed with several key principles in mind:

- It presents a low-risk approach to achieving a standardized market in the Northeast, minimizing disruptions to current markets;
- It includes the "best practices" from the NYISO, ISO-NE, and elsewhere that should be included in the Northeast market design;
- It incorporates significant market improvements early in the implementation process, including ISO-NE's SMD 1.0 and NYISO's transition to SMD 2.0 and the continued resolution of "seams issues," including improved ramp management and transaction scheduling;
- It is compliant with the Commission's market standardization initiative; and
- It is vendor-neutral.

Designated senior representatives from both ISO-NE and the NYISO (the "RTO Management") will direct the NERTO implementation, including the development of a standard market design, creation of a region-wide dispatch and operations plan, and the development of integrated business functions, including settlement and billing, customer service, and other functions required to administer NERTO's responsibilities. The RTO Management Team will oversee the development of the NERTO using detailed work plans that include key milestones for tracking progress and identify specific risks to be addressed in the process.

The RTO Management Team will be comprised of individuals from various business functions, including market design, operations, settlement and billing, and customer service. It will oversee the NERTO market design process, identify and manage operational issues, oversee development and implementation activities, and address stakeholder concerns. The major elements of the Implementation Plan are summarized in Figure 1 of the Petition.

1 NERTO Integration

The early stages of the Implementation Plan focus on establishing and integrating the NERTO organization in parallel with market design and implementation activities. It is important that uncertainty is removed as early as possible so that the NERTO can focus on the market implementation.

After the NERTO receives approval from the Commission, the Board will be established and the senior executives will begin performing their duties. The Implementation Plan anticipates that this would occur by June 30, 2003. With this centralized leadership in place to provide direction, the implementation approach can be validated and potentially accelerated by employing greater re-use of interim market solutions. Additionally, the centralized leadership can provide the organization with clear direction to move forward with integration activities. Integration activities will focus on business processes, supporting technologies, and organization structure and size. There will also be activities to centralize RTO Management, Corporate Services (HR, Legal, Finance, Public and Government Affairs, and Program Management), and RTO Services (ATC, TTC, OASIS, Planning, and Market Design) into a single NERTO headquarters.

2 Market Design and Implementation

2.1 Overview of Regional Standard Market Design

When its market evolution is completed, the NERTO will operate a seamless energy market that spans the entire Northeastern region of the United States. Furthermore, the NERTO will be closely integrated, through the NPCC Common Market, with the Canadian energy markets to the north. The NERTO Market will also be consistent with the Commission's standardized market design requirements. In short, the NERTO will implement the

Commission's vision for standardized markets in both design and operation through its market implementation plan.

The NERTO Market will serve approximately 33 million people, with expected NERTO-administered settlements of $7 billion annually. The implementation of markets for an RTO of this size and scope will require a significant effort over several years. The initial phase of the NPCC Common Market (which will include Ontario and New Brunswick) will have a total of 86,000 MW of load and 98,000 MW of generation, and will serve 45 million people. Expansion of the NPCC Common Market to include other NPCC provinces would further increase these figures.

The following discussion provides a description of the NERTO Market. It also summarizes the elements of the Implementation Plan and describes the efforts that will be undertaken to form the NPCC Common Market. The ISOs anticipate that one of the early actions of the NERTO Board will be to cause management to draft a more detailed and improved system migration and implementation plan that draws on the expertise of both ISO development teams. The NERTO will work with stakeholders through the NERTO stakeholder process on continued development of the NERTO Market design and the Implementation Plan.

SMD 2.X will be based on SMD 1.0, which ISO-NE is currently developing, and SMD 2.0, which will be developed for New York, including modifications to incorporate identified best practices. When fully implemented, the NERTO Market will include day-ahead and real-time energy markets co-optimized with regulation and reserves markets, LMP-based dispatching and congestion management, a system of FTRs, security-constrained unit commitment, nodal *ex post* pricing, and a uniform ICAP market. Both physical and "virtual" bids and offers will be permitted in the NERTO-administered day-ahead energy market. All market participants will have the option to hedge the risk of congestion within the NERTO by purchasing financial transmission rights in flexible multi-period auctions and in a liquid secondary market. Participants will be able to engage in bilateral or self-supply transactions instead of participating in the NERTO Market. The NERTO Market design will be consistent with the Commission's standardized market design principles that are being developed in the rulemaking in Docket No. RM01-12-000.

The NERTO will promote robust demand-side response mechanisms, including a day-ahead demand response program based on the current New York model, to be expanded through the Northeast. These demand-side mechanisms will ultimately include the ability for qualified demand resources to participate in the ancillary services markets. The NERTO will also administer an ICAP market based on the unforced capacity design currently used in New York and PJM, at least until such time as reserve markets and demand-side response mechanisms are proven to obviate the need for an ICAP market in the Northeast. Under SMD 2.X, the NERTO will establish locational requirements for reserves. It will also employ prospective mitigation measures that will be incorporated into its software to remedy market power abuses in the day-ahead market and in real-time in New York City.

The NERTO real-time market will use a real-time scheduling and dispatch process consistent with its day-ahead security constrained unit commitment ("SCUC") model. This model includes a real-time, security-constrained scheduling process that looks ahead three hours and executes at fifteen-minute intervals and a dispatch process that looks ahead one hour and executes on five-minute intervals. The SCUC will replace the separate Balancing Market Evaluation and Security Constrained Dispatch mechanisms currently used in New York.

2.2 Phased Implementation of Regional Standard Market Design

The ISOs have developed a preliminary, three-stage Implementation Plan that will deliver the benefits of NERTO, the NERTO Market and the NPCC Common Market to the Northeast promptly and reliably. The Implementation Plan is aggressive but achievable.

The proposed SMD 2.X includes a number of sophisticated features that are consistent with, but not yet included in, either SMD 1.0 or the current NYISO market design. The ISOs estimate that the system-build, testing, and implementation of SMD 2.X can be completed in the 2005/2006 timeframe, i.e., once the markets are standardized and have been in operation across the region. During development of SMD 2.X, the NERTO will progressively improve and integrate the New England and New York markets in stages, as described below.

Stage 1 will be reached during the first quarter of 2003. At this time ISO-NE will transition to SMD 1.0 market rules while the NYISO continues to operate under its current market rules. SMD 1.0 will include LMP pricing, nodal pricing, losses, a day-ahead market, spinning reserve and regulation markets (spinning reserve markets will be added after the initial SMD 1.0 implementation). In addition, the SMD 1.0 market design will include the following:

- Nodal pricing at load buses;
- *Ex post* real-time pricing;
- Ability to accommodate transaction changes at fifteen-minute intervals;
- "E-schedules" for internal transactions permitting changes up to the start of daily settlement;
- Self-commitment by generation;
- Self-scheduling by generation; and
- Ability to accept Short Notice External Transactions.

The NYISO will work with its software vendors during this period to enhance its market design. The result of these enhancements – SMD 2.0 – will incorporate key market design features of SMD 1.0 plus certain other enhancements and leading practices to its real-time balancing market. SMD 2.0's features include:

- Simultaneous co-optimization of ancillary services and energy in day-ahead and real-time market commitment decisions;
- 10-minute spinning and non-spinning day-ahead and real-time reserve markets;
- 30-minute day-ahead and real-time operating reserve markets;
- Accommodation of demand-side participation in reserve markets;
- Automated *ex ante* mitigation procedures in day-ahead markets and in real-time in New York City;
- Price-responsive day-ahead demand reduction program;
- Ability to bid negative prices;
- Locational reserves;
- Generator bids that may vary by hour; and
- Generator bids that may change up to one hour in advance of real-time.

The NERTO is expected to be formed by the end of the second quarter of 2003. After the NERTO is formed, an organizational integration team will be responsible for the rationalization, integration and migration of the two current ISO business entities to the new administrative and operational structure of the NERTO.

Stage 2 will be reached in the first quarter of 2004, with New York's transition to operation under SMD 2.0, and is expected to last until delivery and testing of the SMD 2.X systems and software. After Stage 2 is reached, the team will determine the remaining steps necessary to move to SMD 2.X. The features of SMD 1.0 and SMD 2.0 to be included in SMD 2.X will be based on an assessment of the performance of SMD 1.0 and SMD 2.0 as well as the Commission's standardized market design. Additionally, the team will prepare for the transition to SMD 2.X by developing detailed testing processes, regional operating procedures, and training programs for both staff and customers.

Preparatory activities leading to Stage 3 will include delivery and installation of the systems and software necessary to support the NERTO's major SMD 2.X components. To provide necessary backup systems for secure market and system operations, the ISOs currently expect to create appropriate redundancy through the use of both existing control centers.

Finally, the NERTO will test all of the system components, train NERTO personnel and market participants, and conduct complete market trials. The ISOs expect the NERTO to reach SMD 2.X, i.e., Stage 3, in the 2005/2006 timeframe.

The Implementation Plan is phased to allow the NERTO to realize regional market benefits from the elimination of export fees and seams and standardized New York and New England markets, prior to any implementation of a single dispatch and common settlement. The early phases of the plan also include the activities and tasks required to meet the minimum functional requirements of an RTO (i.e., centralized TTC, ATC, OASIS, OSS and Planning). These early phases are followed by integration of administrative functions seeking synergies and the design, building, testing and implementation activities.

2.3 Interface with Neighboring Control Areas

Because the NERTO region is so closely interconnected with neighboring NPCC Canadian system operators and conducts such a high volume of trade with those entities, the NERTO will work closely with these Canadian system operators to develop and implement the NPCC Common Market, that is, a seamless NPCC trading area. The ISOs have taken a variety of steps, particularly with Ontario, to eliminate seams to the extent possible, considering international jurisdictional and sovereignty concerns. The ISOs hope to be in a position to report even greater progress in the near future. In addition, the RTO Management Team will continue current efforts to identify and address any remaining "seams" and other potential barriers to trade with PJM, as discussed below. A comprehensive summary of seams issues resolution between and among the Northeast ISOs, together with the current schedule for addressing the remaining seams issues, can be found in Appendices A and B of this Attachment.

2.3.1 Ontario

The IMO region has a peak load of approximately 25,300 MW and 29,500 MW of generating capability. Its territory encompasses 1.1 million square miles, has a population of 12 million, 6.6 million electricity customers and 17,918 miles of transmission lines. In addition to its interconnections with other provinces, the IMO region has a maximum export capability to New York of 2,500 MW, constituting almost half of the overall maximum Canadian export capability of 5,050 MW to the NERTO region.

The NYISO and the IMO have already developed improved scheduling procedures to minimize the seams problems associated with the differences between their current market designs and to facilitate transactions. In early June 2002, the ISOs and the IMO entered into a System Operations, Planning and Market Development Agreement ("IMO Agreement"). The IMO Agreement commits the parties to continue their existing efforts to coordinate transaction procedures, ensure that the transfer capabilities of shared interfaces are calculated consistently, develop reserve sharing mechanisms and institute cooperative system expansion and planning procedures. The IMO Agreement also specifies that the parties will establish a "Coordinating Committee" to develop recommendations on market design, market surveillance, business practices, system planning protocols and other coordination activities to reduce barriers to trade and improve reliability. The Coordinating Committee has had an initial, productive meeting and will meet on a regular basis. Nothing in the IMO Agreement precludes future expansions of the Coordinating Committee to include other systems.

In addition, the IMO Agreement establishes a staged plan for increasing the integration of the IMO and NERTO markets. In the first phase, the Coordinating Committee will present recommendations and implementation milestones to the ISO and IMO Boards regarding short-term objectives, such as:

- possible enhancements to better harmonize the existing markets;
- the IMO's possible adoption of components of the Commission's standardized market design that are suitable for Ontario; and
- possible modifications to the NERTO's market design to accommodate the IMO's needs and ensure seamless trading with Ontario.

In the second phase, the Coordinating Committee will present recommendations and implementation milestones to the Boards regarding intermediate-term objectives, such as:

- eliminating export charges;
- coordinating system planning;
- adopting standardized market monitoring and mitigation rules; and
- standardizing transaction scheduling procedures to permit one-stop shopping.

Finally, in the third phase, the Coordinating Committee will submit recommendations and implementation milestones to the Boards regarding long-term objectives such as the introduction of seamlessly compatible and, where possible, standardized market rules, business practices, information standards and market structures.

2.3.2 New Brunswick

Énergie NB Power serves a market with a peak load of approximately 2,800 MW and 4,100 MW of generating capability. Its territory encompasses 27,566 square miles, with a population of 760,000, approximately 340,000 electricity customers and 4,092 miles of transmission lines. New Brunswick is in the process of implementing wholesale and retail competition programs. The province is currently considering a market design focused on bilateral trading arrangements and Order No. 888 type open-access provisions that would not reflect the Commission's SMD principles. However, the ISOs have had productive discussions with representatives of the vertically-integrated provincial utility, Énergie NB Power, and the ISOs and Énergie NB Power have entered into an "Agreement on Enhancing Coordination of System Operation, Planning, and Market Development" (the "Énergie NB Power Agreement"), which is summarized below and included as Attachment III to the Petition. The ISOs are optimistic that New Brunswick will ultimately institute a market design that is compatible with the NERTO's.

The Énergie NB Power Agreement states general principles reflecting the joint goals of the ISOs and Énergie NB Power, provides for formation of a liaison committee, and establishes near-term, intermediate-term and long-term objectives. The joint goals include increased integration of services and compatibility of market designs. The liaison committee will meet regularly to advance the objectives of the Énergie NB Power Agreement, including the development and tracking of schedules for attaining these objectives.

Near-term objectives include:

- streamlining of transaction scheduling;
- expansion of transfer capability;
- consolidation of security coordinator function;

- coordinating calculation of available transfer capability and total transfer capability;
- integration of Area Control Error; and
- coordination of maintenance.

Intermediate-term objectives include:

- reserve sharing; and
- joint system planning.

Long-term objectives will involve identification of other goals conducive to achieving an end state of seamless markets across all NPCC control areas, including exploration of the following (recognizing the pendency of Énergie NB Power's market redesign and industry restructuring process):

- achievement of common market design and common energy products;
- single day-ahead commitment and real-time dispatch across the entire region;
- elimination of barriers to trade; and
- coordinated or consolidated market monitoring.

2.3.3 PJM Interconnection

The RTO Management Team will continue current efforts to identify and address "seams" and other potential barriers to trade with PJM. They will also continue to confer with PJM on market design matters. The NYISO and PJM have made great progress recently in addressing seams issues through enhanced control area checkout and transaction management processes, the implementation of an interregional congestion management pilot, and significant steps toward harmonizing the ICAP rules to allow suppliers in New York to sell ICAP to load serving entities in PJM. On March 15, 2002, the NYISO and PJM executed an Interregional

Coordination and Issue Resolution Agreement with the specific goal of resolving any remaining seams between the two control areas on an expedited basis. This Agreement includes the development of a prioritized workplan, a formal dispute resolution process and quarterly reporting of progress to both the Commission and State PUC's. The NERTO will continue in these efforts after its formation. To insure that new barriers are not created in the process of implementing the NERTO, the RTO Management Team will continue to review key elements of the NERTO market design with PJM staff and seek their input to ensure that SMD 2.X supports and enhances regional trade.

2.4 NERTO Tariff Development

When NERTO operations begin, the NERTO will administer an umbrella tariff that will address the transmission and market arrangements for the New England and New York control areas. This tariff will eliminate "border charges" for transactions between those control areas. The ISOs recommend that elimination of border charges be conditioned on the consideration by the Commission and the states, on an expedited basis, of mechanisms by which the TOs can recoup lost revenues stemming from the elimination of border charges. Those mechanisms should be designed to avoid distortions in the operation of the wholesale power market.

2.4.1 The "Day One" NERTO Tariff

The ISOs will submit, pursuant to FPA Section 205, a "Day One" Tariff to become effective on the day that the NERTO commences operations. That tariff will consist of New York and New England sub-regional tariff sets, as well as incorporating certain existing ISO tariffs/documents (with limited modifications), under an overarching "umbrella" document.

The umbrella portion of the tariff will explain the overall transmission access and electricity market arrangements that will be in place on "Day One." It will incorporate provisions establishing the NERTO planning and expansion process and the NERTO interconnection process for the two sub-regions. The umbrella tariff will address the cost allocation for new regulated transmission facilities built pursuant to the NERTO System Plan ("NSP") and for interconnection-related upgrades, and provide for the recovery of the NERTO's administrative and start-up costs.

In addition to the umbrella provisions, the Day One tariff will include sub-regional tariff sets for the New York and New England control areas. For New York, the sub-regional tariff set will include the existing NYISO OATT and the Market Administration and Control Area Services Tariff, modified to be NERTO documents. The New York sub-regional tariff sets will provide for the recovery of any NYISO start-up costs that are not recovered by the first day of NERTO operations. For New England, the sub-regional tariff sets will include relevant portions of the Restated NEPOOL Agreement and the NEPOOL OATT (modified to be NERTO documents rather than NEPOOL documents), recovery of any remaining ISO-NE restructuring costs and ISO-NE's Market Rule 1 reflecting SMD 1.0.

When the NERTO commences operations, the substantive contents of the sub-regional tariff sets will remain largely as they are today, albeit with modifications reflecting the progressive harmonization of the NYISO and ISO-NE systems prior to the NERTO's launch. Accordingly, the sub-regional tariff sets will retain the existing transmission rate designs in New York and New England. In New York, those provisions would include the individual TOs' Transmission Service Charges and the New York Power Authority Transmission Adjustment Charge.

Specialized local provisions will also remain in force. Such provisions include tax-exempt provisions for LIPA, NYPA and Con Edison, which are discussed in Section IX of the Petition, and retail rate design provisions currently in effect in New York. The tariff will accommodate retail access programs in New York and New England. The provisions for New England would include the Regional Network Service and Point-to-Point Transmission Service rates under the regional OATT. Therefore, coupled with the elimination of the border charges between the two regions, customers paying regional rates in New York can use transmission in New England without additional charge, and vice versa. On Day One, the New England TOs' local tariffs would remain in place to permit the observance of the existing NEPOOL rate settlement, pending the development of a "Day Two" Tariff as described below. Currently excepted and grandfathered transactions and long-term TCCs and TCCs awarded for transmission expansions will remain in force.

2.4.2 The "Day Two" NERTO Tariff

The Day One Tariff will evolve to reflect changes in the NERTO's markets. Ultimately, there will be a "Day Two" Tariff uniformly governing the NERTO's provision of open-access transmission service and administration of electricity markets across the entire NERTO region. The NERTO will work with the TOs and with other stakeholders to develop the rate design for the Day Two Tariff. The Day Two Tariff will supersede the Day One Tariff effective with the commencement of SMD 2.X. This should occur in the 2005/2006 timeframe.

The regional TOs have not yet proposed an incentive or performance-based transmission rate proposal. Such arrangements are currently under discussion, will be discussed with stakeholders, and may be the subject of future filings by the TOs.

2.4.3 Elimination of Existing Border Charges

As noted above, the Day One Tariff will eliminate border charges for transactions between the New England and New York control areas. As noted above, the ISOs recommend that the elimination of border charges be conditioned on the consideration by the Commission and the states, on an expedited basis, of mechanisms by which the TOs can recoup lost revenues stemming from the elimination of border charges. Those mechanisms should be designed to avoid distortions in the operation of the wholesale power market.

3 System Design and Implementation

3.1 Technology Assessment

The RTO Management Team will define a target systems architecture for the NERTO designed expressly to support SMD 2.X, including both a systems infrastructure and systems applications. A high-level assessment of the systems infrastructure and applications currently in use by ISO-NE and NYISO will be conducted to determine the extent to which current systems already in use or commercially available are able to meet the performance requirements of the NERTO's SMD 2.X. An estimate of the development costs for the necessary system enhancements will also be included in the technical assessment**.** An executive summary of Phase I of the technology assessment is contained in Attachment IX to the Petition.

3.2 System Implementation

3.2.1 Technological Solution Design

Based on the systems architecture developed in the technology assessment phase, the RTO Management Team will work with suppliers to develop comprehensive proposals for power, market, and settlement systems, with "blueprints" for their proposed technical design and firm price quotes. In assessing and selecting vendors, the RTO Management Team will analyze proposals based on their capability to meet the NERTO requirements, the extent to which proposals make use of existing technology that can be scaled to meet the needs of the NERTO, and overall performance and cost considerations

3.2.2 System Implementation and Data Transfer

The systems implementation phase is planned to begin in mid-2004, following the implementation of SMD 2.0. It begins with a systems "build period" that is estimated to last one year, with delivery of the SMD 2.X systems and software to the NERTO testing facilities scheduled for the third quarter of 2005. During the build period, the RTO Management Team will conduct unit and factory acceptance testing of all system software. Following system delivery, the RTO Management Team will oversee the conversion and transfer of data from existing systems to the new NERTO systems. Operational procedures will be developed during this period, and appropriate personnel will be trained on the NERTO systems.

3.2.3 System Testing

Following initial product delivery, the RTO Management Team will oversee installation and testing of the NERTO systems. Testing activities will include simulated operation of the NERTO control area, network testing, and detailed market and operations application tests. After the internal system testing is completed, comprehensive market trials will be conducted with market participants to ensure that all systems are ready for live operations.

4 Facilities and Operations

One of the first tasks of the RTO Management Team will be to identify and allocate staffing and other resources sufficient to develop and implement the NERTO while the ISOs continue to operate. The NERTO must have adequate staff, facilities, and resources to operate a robust, secure, and uninterrupted bulk electric system and market before it can assume those responsibilities from the ISOs. Accordingly, the RTO Management Team will develop a plan that meets these requirements while taking full advantage of existing systems, infrastructure, and technology of the existing ISOs.

4.1 Facilities

4.1.1 Interim

The RTO Management Team will develop a short-term plan to provide for the staffing needed to develop and implement the NERTO. In addition, the RTO Management Team will define the space and infrastructure requirements for these functions and identify the best means of using the existing facilities and assets of ISO-NE and NYISO.

4.1.2 Permanent

To capitalize on existing facilities and resources, the current ISO control centers will be modified so that each can serve as the NERTO operations control center, with the other serving as the back-up operations control center. At any time, either of these two control centers will be designated as the primary NERTO control center at all times and the other will be designated as the back-up control center. The primary NERTO control center will conduct region-wide functions while both the primary and the alternate control centers continue to perform local control functions, including real-time system control and monitoring. Both control centers will have identical systems, with full system redundancy at both centers and between the centers. Upon full implementation of the NERTO, each of the control centers will be capable of immediately assuming full responsibility for the entire range of NERTO functions and services in the event the primary control center is disabled.

4.2 Planning

A common planning process will be adopted upon the effectiveness of the Day One Tariff. The organizational and technical requirements for establishing a common planning process will include the formation of a Planning Advisory Committee, a NERTO Board of Directors planning committee, and the alignment of the existing planning staffs within ISO-NE and NYISO.

4.3 Interconnection

A single interconnection process for the NERTO control area will be implemented immediately upon the effectiveness of the Day One Tariff. This interconnection process will combine the best features of the existing, Commission-approved interconnection processes now in place in New York and New England and will address any new requirements that are established in the Commission's notice of proposed rulemaking regarding interconnection standards. It would be effective on the first day of NERTO operations for all new projects and would include appropriate grandfathering provisions in order to accommodate projects already in the existing New England or New York queues.

4.4 Market Operations

The RTO Management Team will closely coordinate the development of joint market operations with the efforts to develop joint power system operations, as described below. Market rules will account for the physical characteristics of the Northeast region as a whole, including system constraints and contingencies.

4.5 Power System Dispatch and Operations

The RTO Management Team will oversee extensive technical studies and analysis to define the operational requirements for the region, including regional reserves, regulation, and reactive support requirements. Through this process, the RTO Management Team will identify the physical characteristics of the Northeast region as a whole that are likely to impact upon operations, including system constraints and a comprehensive set of system contingencies. The RTO Management Team will then direct the development of regional reliability requirements and a transition plan for applying the new requirements in the NERTO control area. The RTO Management Team will also oversee the development of a common set of operating procedures to be applied through the NERTO control area.

4.6 Settlement and Billing

The RTO Management Team will analyze the business processes and key features of the NYISO and ISO-NE settlement and billing functions. In addition, the RTO Management Team will work with stakeholders to identify the best practices of the ISOs and elsewhere. The RTO

Management Team will examine the impact of market design changes on the settlement and billing process and will develop an approach that is flexible, reliable, and customer-oriented. The RTO Management Team will identify key steps required for the transition to SMD 2.X, while addressing the need to maintain the systems and data currently in use for several years.

4.7 Market Monitoring and Mitigation

The internal unit will be part of the NERTO, and will be appointed by and report directly to the NERTO's chief executive officer. The internal unit will also have a regular reporting relationship with the Board, which is expected to include periodic meetings, with executive sessions as needed. The internal unit will (i) perform real-time market monitoring for efficiency, competitiveness, anomalies, etc., (ii) when necessary, implement Commission-approved market mitigation measures, (iii) directly provide the Commission with unfettered access to data and records necessary to perform its regulatory oversight function, and (iv) consult with the external market monitoring unit to ensure that the markets are operating and evolving appropriately and, where required, to develop rule changes and other modifications to ensure appropriate market outcomes.

The external independent market monitoring unit (the "IMMU") will be a person or persons external to the NERTO staff. The IMMU will regularly report directly to the NERTO Board and will provide defined regular reports simultaneously to the Commission, the Board and state regulators. The IMMU will be appointed by the NERTO Board, with notification to the Commission. Any termination (voluntary or involuntary) of the IMMU must also be reported and explained to the Commission by the NERTO Board and the IMMU. The IMMU's functions and responsibilities will include, at least: (i) monitoring the markets for efficiency, competitiveness, anomalies, etc., including identifying flaws in the design and application of the market rules and procedures, (ii) monitoring the NERTO's administration of the market rules and procedures to ensure that NERTO practices do not result in improper market outcomes, (iii) consulting and advising the internal market monitoring unit on market efficiency and market power issues, (iv) notifying the Commission if the NERTO's administration of the markets is improper or incorrect, and (v) providing regular reports to the Commission, the NERTO Board, state regulators and market participants on the state of the market and its evolution. Finally, market participants will have direct access to the IMMU, as they do today with the ISOs' independent market advisor, and stakeholders may submit complaints or requests for investigations to the IMMU. This will help ensure the integrity of the market and facilitate the rapid identification of issues that compromise its efficiency.

In addition to these internal and external market monitoring functions, the NERTO Board will, with stakeholder input, hire an external auditor with appropriate qualifications for the purpose of ensuring that NERTO operation complies with the market rules. The NERTO will manage all operational audits and receive the reports resulting from those audits directly. Given the specific skills set necessary for the performance of these operational audits, these operational audits will not come within the purview of the market monitoring units.

4.7.1 <u>The NERTO Market Monitoring Plan</u>

The NERTO will monitor the energy and ancillary services markets that it administers for evidence of potentially abusive behavior associated with market design flaws or residual market power. Vigilant monitoring will be necessary because opportunities for the exercise of market power will continue to exist in the portions of New England and New York with slim reserve margins, highly concentrated generation ownership and severe transmission congestion, regardless of what market design is implemented by the NERTO. The NERTO will also monitor the effects of bilateral transactions on its markets and, to the extent practicable, evaluate the conditions or events outside of the NERTO region that affect the supply and demand for, or the quantity and price of, products and services sold in any of the NERTO-administered markets. Finally, the IMMU will prepare annual reports on the competitive structure and performance of the NERTO markets, other conditions in or affecting competition in those markets and their economic efficiency.

The NERTO will initially utilize the existing market monitoring plans of the ISOs. These plans will be very similar on the first day of NERTO operations, as the ISOs' existing plans already are today, and they will progressively converge as the ISO markets come together pursuant to the single market implementation plan.

4.7.2 NERTO Market Power Mitigation Measures

The NERTO's market power mitigation plan will be modeled on the NYISO's recently accepted comprehensive market power mitigation measures, which have recently been adopted for use by the California ISO. ISO-NE contributed to the formulation of the NYISO's comprehensive measures and is currently working to adopt a similar system for use in New England concurrent with the implementation of SMD 1.0. Until such time as the NERTO Market is in place, however, the NERTO will administer the mitigation plans for New England and New York. As with the NERTO's monitoring plans, the regional mitigation plans will be very similar and will progressively converge over time as the ISO markets move together. The final versions will reflect an allocation of responsibilities between monitoring entities.

Mitigation measures are necessary in the NERTO region because high levels of congestion, low reserve margins and insufficient demand-side responsiveness increase the likelihood of the exercise of market power. This is particularly true in frequently constrained sub-regions like New York City, Long Island, Boston and Southwestern Connecticut. At the same time, the NERTO's mitigation measures will be consistent with the Commission's goals that mitigation be prospective in nature and as non-intrusive as possible.

The mitigation measures focus on mitigating economic and physical withholding. They are designed to distinguish between scarcity and market power conditions and are narrowly tailored to avoid artificially depressing prices or interfering with legitimate bidding behavior. The measures also ensure that suppliers will not be required to sell energy at a price below their production costs (including legitimate opportunity cost). Finally, the measures will automatically cease to operate when the conditions responsible for market power issues in the Northeast subside, e.g., due to the construction of new transmission infrastructure or the implementation of more robust demand response mechanisms, because the mitigation thresholds will no longer be triggered.

The NERTO's mitigation plan will be constructed around a two-part "conduct" and "impact" test. To screen bidders' conduct for potential economic withholding, the NERTO will use past accepted offers over a reasonable period of time as its preferred method for establishing bidder "reference levels." Once reference levels are established, economic withholding can be identified by detecting bids at specified dollar or percentage thresholds above a particular unit's reference level for the output corresponding to the bid. If this conduct test is met, the NERTO will impose prospective mitigation only if the conduct has a significant effect on prices, as determined by the impact thresholds prescribed in the plan. The NERTO will consult with affected market participants to the greatest extent possible before mitigating to afford them an opportunity to justify bids that are legitimate but trigger the conduct and impact screens. In mitigation, a suspect bid will be replaced with a bid set at the appropriate reference level. Mitigated suppliers will still be eligible to receive the market-clearing LMP if they are selected.

Mitigation thresholds will be set at levels that are likely to be reached only if structural problems, for example, transmission congestion, enable the exercise of market power. Lower thresholds will be used for sub-regions, like New York City, that are known to be more vulnerable to market power abuses. The two-part test will be incorporated into the NERTO's day-ahead market software and, with respect to New York City, to its real-time software so that it will operate automatically and without any implementation delays. This is essential because the Commission's insistence that mitigation measures be exclusively prospective means that entities that exercise market power can reap unjust windfalls during any mitigation delays.

In addition, as a temporary demand response proxy, the NERTO tariff and market rules will retain the existing $1,000 cap on offers to sell energy. The bid cap may be eliminated as soon as demand response measures become sufficiently robust to obviate the need for it.

4.8 Credit Monitoring and Enforcement

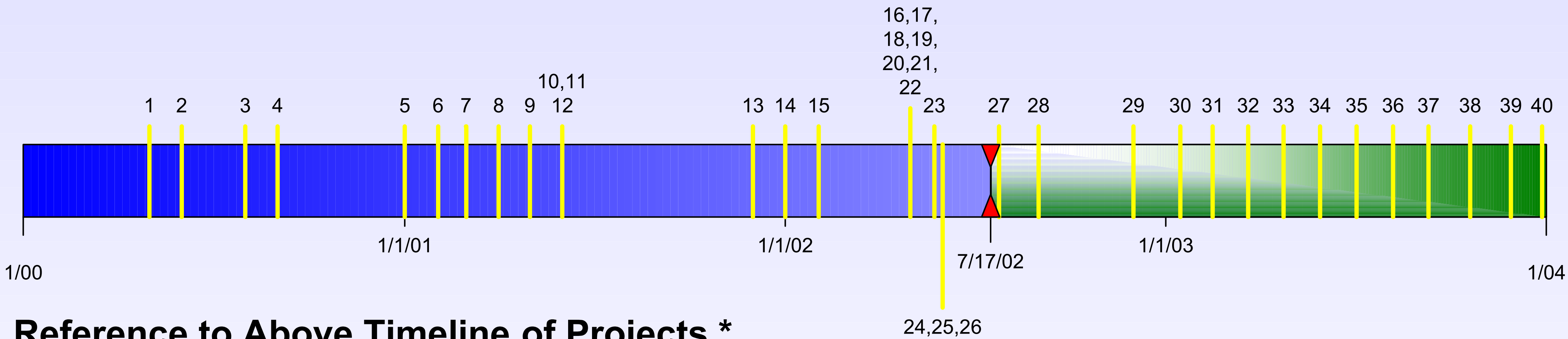
With input from stakeholders and outside credit experts, the RTO Management Team will identify the best practices used in New England, New York, and elsewhere, and will develop credit monitoring and enforcement polices that adequately account for market risk without creating unnecessary barriers to entry into the NERTO-administered markets. The NERTO credit and collection practices will be developed in conjunction with the development of billing and settlement rules to ensure the compatibility of these interrelated functions. In addition, clear standards and procedures for termination of service and transfer of load to a "provider of last resort" will be established for the NERTO.

4.9 Customer Service

The RTO Management Team will define the customer service model and functions for the NERTO and develop a plan for transitioning from the ISOs' existing customer service functions to integrated operation under the NERTO. The RTO Management Team will develop a NERTO customer "life-cycle" model that addresses all phases of customer participation, from registration to termination of service. The RTO Management Team will develop a plan for transferring existing customers to the NERTO, including any necessary customer training components. Throughout these efforts, the RTO Management Team will work with stakeholders to develop business processes and customer interface protocols based on best practices in New England, New York, and elsewhere. In addition, the RTO Management Team will oversee the development of participant training materials and programs in advance of market trials.

APPENDIX A
TO ATTACHMENT VIII

Northeast ISOs "Seams" Resolution (2000 - 2004)



Reference to Above Timeline of Projects *

2000 Seams Projects

1. May - NY Emergency Transfer agreement with PJM
2. June - NYISO Data Feed for PJM E-data tool
3. August - NY Emergency Transfer agreement with New England
4. September - NY prevention of transaction bid production cost guarantee gaming

2001 Seams Projects

5. January - PJM changes timing requirements
6. February - NY reserve sharing with ISO-NE
7. March - NY transaction curtailment notification messages
8. April - PJM modifies NYPP-E /NYPP-W LMP definition
9. May - NY Emergency Transfer Agreement with HQ
10. June - NY's implementation of transaction scheduling desk
11. June - PJM implementation of CSS
12. June - PJM/NY coordination of in-day transaction schedules to help control ramping issues
13. December - NY multi-hour block transactions

2002 Seams Projects

14. January - PJM implements NYIS interface LMP
15. February - NY transaction pre-scheduling
16. May - ISO-NE changes to ICAP rules
17. May - ISO-NE rule changes to permit/facilitate SNETs from ISO-NE to NY
18. May - NY transactions reinstatement
19. May - NY hour-ahead closing time changed from 90 to 75 minutes
20. May - Interim transaction checkout between NYISO & ISO-NE
21. May - IMO seams initiatives
22. May - NY Emergency Transfer Agreement with IMO
23. May - NYISO filing for ICAP deliverability to PJM
24. June - Display TTC /ATC for all interfaces on NPCC website
25. June - NY/PJM implement plan to enhance congestion management
26. June - Area Control Error (ACE) diversity exchange initial deployment
27. July - NY in-day commitment and scheduling enhancements
28. September - NY interconnection agreement with HQ/TE
29. December - Coordination of controllable tie lines between (Phase-Angle Regulators)

2003 Seams Projects (projected)

30. ISO-NE to implement SMD 1.0
31. ISO-NE ICAP implementation
32. NY Real-time Scheduling (RTS) implementation
33. Regional ICAP Working Group implementation
34. Harmonize NY Demand Response Programs with ISO-NE
35. June - Lake Erie emergency redispatch (LEER) project implementation
36. NY new trading hubs
37. NY TCC options for external interfaces
38. Open-scheduling system (OSS) for seams issues
39. Establish requirements for external thirty-minute reserves participation in NYISO
40. NYISO to implement SMD 2.0

*** Descriptions of these projects may be found on the accompanying sheets.**

Revised July 17, 2002

APPENDIX B
TO ATTACHMENT VIII

Northeast ISOs
Seams Resolution Report
History of Seam Issues Resolution

2000

1. **May 2000 – NY EMERGENCY TRANSFER AGREEMENT WITH PJM** – ensures that energy will flow across control area boundaries during emergency situations

2. **June 2000 - NYISO DATA FEED FOR PJM E-DATA TOOL** – provides NY zonal and generator LBMP data electronically for display on PJM's e-Data tool.

3. **August 2000 – NY EMERGENCY TRANSFER AGREEMENTS WITH ISO-NE** – ensures that energy will flow across control area boundaries during emergency situations

4. **Sept 2000 – NY PREVENTION OF TRANSACTION BID PRODUCTION COST GUARANTEE GAMING -** by scheduling transactions in NY and canceling them (or not scheduling them) in neighboring control areas, resulting in improper payments in NY and ramping difficulties in PJM. Immediate corrective action taken with a permanent fix implemented in the NY market software making this gaming scheme unprofitable.

2001

5. **Jan 2001 – PJM CHANGES TIMING REQUIREMENTS –** PJM implemented new business rules to allow schedule changes through the Enhanced Energy Scheduling (EES) system with only 20 minutes notice.

6. **Feb 2001 – NY RESERVE SHARING WITH ISO-NE –** Phase 1 allows NY to include 300 MW from ISO-NE as 30-min. reserves. Phase II (sharing of up to 100MWs of 10-minutes reserves) effective 6/15/01.

7. **March 2001 – NY TRANSACTION CURTAILMENT NOTIFICATION MESSAGES –** enhanced communication process by improving informational messages when transactions are not scheduled or curtailed.

8. **April 2001 – PJM MODIFIES NYPP-E/NYPP-W LMP DEFINITION –** PJM's NYPP-W and NYPP-E interface points are combined into a single New York Interface point. The two interfaces will continue to be used but the price at these points will be the same and reflect the definition of a single NY interface point.

9. **May 2001 – NY EMERGENCY TRANSFER AGREEMENT WITH HQ** – ensures that energy will flow across control area boundaries during emergency situations

10. **June 2001 – NY'S IMPLEMENTATION OF TRANSACTION SCHEDULING DESK** – NYISO implemented an additional scheduling position in the Control Room that can be directly accessed by market participants to address real-time scheduling questions and problems. Timely provision of information reduces business risk and facilitates a level playing field for all MP's.

11. **June 2001 – PJM IMPLEMENTATION OF CSS –** PJM implements the Collaborative Scheduling System (CSS) which is part of the EES system. It allows users to submit scheduling information to one place and the information is sent to the NY MIS system for processing.

12. **June 2001 – PJM/NY COORDINATION OF IN-DAY TRANSACTION SCHEDULES TO HELP CONTROL RAMPING ISSUES –** To help control ongoing ramping problems between NY/PJM schedules, PJM implemented an approval process for all hourly (HAM equivalent) PJM/NYISO schedules. These schedules will only be approved and hold ramp after being checked out hourly with the NY-ISO.

13. **Dec 2001 – NY MULTI-HOUR BLOCK TRANSACTIONS** - Develop process to accept and schedule external LBMP energy transactions with minimum run times. Allows a marketer to arrange the 5-day by 16-hour market products commonly offered in existing Trading Markets.

2002

Jan 2002 – ISO-NE and NYISO announce agreement providing for the development of a plan to establish a common market design and to evaluate a New England and New York RTO.

14. **Jan 2002 – PJM IMPLEMENTS NYIS INTERFACE LMP –** The NYPP-W and NYPP-E interface points are converted into a single New York Interface point (NYIS).

Jan 2002 - PJM and MISO announce plan to develop a joint and common wholesale market in all or parts of twenty seven (27) Midwest and mid-Atlantic states, the District of Columbia, and the province of Manitoba. This removes the potential for seams over a large portion of the Eastern Interconnection.

15. **Feb 2002 – NY TRANSACTIONS PRESCHEDULING** - An external LBMP or wheel-through preschedule request may be submitted up to 18 months prior to the effective transaction date. A preschedule request is checked for ramp and ATC before being approved. It is then given economic priority in the scheduling software over other external transactions that are not prescheduled, to provide the greatest certainty that the transaction will flow. NYISO implementation of Long-term Pre-scheduling provides comparable treatment of long-term firm service with PJM firm and "non-firm willing to pay congestion" service options. Long-term pre-scheduling allows preferential (firm) treatment of transactions, consistent with PJM & ISO-NE SMD 1.0, and addresses scheduling requirements for bundled ICAP/Energy products.

April 2002 - PJM and Allegheny Power System form PJM West -- The larger energy market provides one market with a common transmission tariff, business practices and market tools, thus eliminating seams issues between Allegheny Power and PJM.

16. **May 2002 - ISO-NE CHANGES TO ICAP RULES** - amending procedures for submitting external ICAP transactions between ISO-NE and NYISO. The changes to ISO-NE Market Rule 4 insure that imports from NY to NE will not exceed the TTC of the New York ties.

17. **May 2002 - ISO-NE RULE CHANGES TO PERMIT/FACILITATE SNETS FROM ISO-NE TO NY** – FERC Order dated 4/26/2002; ISO-NE can use all available resources to support short notice external transactions (SNETs) as long as ISO-NE replacement reserves aren't depleted in doing so. The short-notice scheduling capability gives market participants the ability to schedule new transactions on an hourly basis in a manner compatible with the hourly market.

18. **May 2002 – NY TRANSACTIONS REINSTATEMENT** - for transactions curtailed for in-hour due to reliability violations. NYISO will reinstate external transactions in-hour as soon as the reliability problem is resolved (previously the transaction had to wait until the next hour-ahead commitment run).

19. **May 2002 – NY HOUR-AHEAD CLOSING TIME CHANGED FROM 90 TO 75 MINUTES** - to allow for closer coordination with ISO-NE, which uses a 75-minute closing time. This allows MPs to use more current information in formulating transaction strategy.

20. **May 2002 - INTERIM TRANSACTION CHECKOUT BETWEEN NYISO AND ISO-NE** - This NYISO/ISO-NE Interim Transaction Checkout Tool addresses a seams issue requirement to enhance checkout for summer 2002 until OSS is deployed. It provides an electronic means of sharing transaction information to assist the operators during checkout and identify transaction issues more easily.

21. **May 2002 – IMO SEAMS INITIATIVES** – implemented a procedure that permits staggered HAM closing times – IMO generally closes their market to MP's 2 hours before the hour – a process is in place that will evaluate their accepted NY import/export bids in the hour-ahead commitment. Also, an interconnection agreement between NYISO and the IMO was made effective on May 1, along with several critical joint control room procedures.

22. **May 2002 – NY EMERGENCY TRANSFER AGREEMENT WITH IMO** – ensures that energy will flow across control area boundaries during emergency situations

23. **May 2002 – NYISO FILING FOR ICAP DELIVERABILITY TO PJM** – NYISO filed with FERC on May 24 to modify its tariff to provide delivery of ICAP purchased by PJM from NY suppliers, allowing NY generators the opportunity to meet the PJM deliverability requirement and participate in the PJM ICAP market.

June 2002 – **IMO, ISO-NE, NYISO sign agreement to work cooperatively to harmonize market rules, eliminate Seams issues and develop larger markets for energy and ancillary services. Elimination of export charges is a priority.**

24. **June 2002 - DISPLAY TTC/ATC FOR ALL INTERFACES ON NPCC WEBSITE** – provides market participants with a single location to view the most limiting values across neighboring control area interfaces. NPCC has developed a website where regional MP's can view in one location the TTC/ATC values for all regional interfaces.

25. **June 2002 – NY/PJM IMPLEMENT PLAN TO ENHANCE CONGESTION MANAGEMENT -** under specific conditions between NY and PJM through control room operating procedures. The pilot provides a means to relieve congestion in western PJM by shifting generation in NYISO.

26. **June 2002 – AREA CONTROL ERROR (ACE) DIVERSITY EXCHANGE INITIAL DEPLOYMENT** - intended to enhance regulation performance. Initial implementation with NYISO and ISO-NE participating; other NPCC Control Areas to participate when IT resources are available. Takes advantage of the diversity among the control areas to reduce the burden on regulating units that should aid regulation performance.

27. **July 2002 – NY IN-DAY COMMITMENT AND SCHEDULING ENHANCEMENTS -** This project implements consistent treatment of reserves in NYISO's hourly and real-time markets which will improve price convergence at the proxy (boundary) transaction busses with the neighboring control areas.

28. **Sept 2002 – NY INTERCONNECTION AGREEMENT WITH HQ/TE** - In addition, review of potential for increasing the 7040 transmission line import limit above 1500 MW and evaluation of ways to better utilize NY-HQ-ISO-NE DC facilities are scheduled to be addressed by the end of 2002.

29. **Dec 2002 – COORDINATION OF CONTROLLABLE TIE LINES (PHASE-ANGLE REGULATORS) -** for both day-ahead and real-time to support the ultimate FERC ruling on the PSEG-ConEd wheeling contracts. NYISO & PJM will develop procedures to coordinate the setting of the PARS and address same in their respective unit commitment and dispatch programs. Actual implementation within 60 days of FERC order.

Dec 2002 – PJM to Implement Spinning Reserves Market

2003

30. **1st Quarter 2003 - ISO-NE TO IMPLEMENT SMD 1.0** – Establishes market standards authority, institutes coordinated transmission planning and standardizes transmission tariff provisions. Under SMD 1.0, ISO-NE will implement LMP with day-ahead and real-time balancing markets similar to those utilized in PJM and NYISO. SMD 1.0/1.X development by ISO-NE provides long-term – firm and "non-firm willing to pay congestion" service options to customers in New England.

31. **1st Quarter 2003 – ISO-NE ICAP IMPLEMENTATION** – ISO-NE to implement NYISO-based ICAP market as part of SMD 1.0. New England market will conform to New York product definitions, schedules and auction processes.

32. **2003 – NY REAL-TIME SCHEDULING (RTS) IMPLEMENTATION** – Real-Time Scheduling (RTS) is a major portion of the overall SMD 2.0 and involves developing new real-time commitment (RTC) and dispatch (RTD) software in place of the current hour-ahead commitment and real-time dispatch

modules. The RTS time frame extends from 5 minutes in the future to 2½ hours in the future. During this period, generating units may be started or shut down, or the output of energy resources may be adjusted. Commitment and decommitment decisions are made every 15 minutes by the real-time commitment (RTC) process. Decisions to adjust the output of internal energy suppliers (dispatch) are made every 5 minutes by the real-time dispatch (RTD) process, as is the calculation of energy and ancillary services prices. RTS / SMD 2.0 development by NYISO enhances existing long-term pre-scheduling options (by providing automated check outs) and introduces In-day Pre-scheduling to complete the needed functionality in the real-time environment. With this development, all 3 Northeast ISO's will explicitly treat firm/non-firm transmission service comparably. In-day Pre-scheduling also addresses real-time ICAP recall requirements for capacity emergencies to assure ICAP deliverability providing comparable treatment to ICAP suppliers with firm tie line reservations.

33. **Projected 2003 - REGIONAL ICAP WORKING GROUP** – Set up to address ways to move the various ICAP markets closer in NYISO, PJM and ISO-NE. The goal is to make ICAP tradable anywhere in the northeast. The Joint Capacity Adequacy Group has developed a number of Near-Term and Long Term Enhancements to improve the ICAP Market design. These are listed below:

<u>Near Term (Dec. 2002)</u>
Common Planning/Capability/Power Year (recommend June 1 – May 31)
Develop common unit summer maintenance period from June 1 to Sept 30
Standardize the UCAP product to be based on the summer capability for the for uniform market design and eliminate seams issues.

<u>Long Term (2004)</u>
Common set of unit testing criteria should be developed and a working group established to address the issue
Differences in wind and solar UCAP valuation should be standardized and a working group established
A working group should be formed to determine if common market rules and operating and scheduling procedures can be developed for DSM
Develop uniform deficiency charges for all of the control areas

Stakeholders will review the recommendations of the JCAG and comment on how and when the changes will be addressed in each area.

34. **Projected 2003 - HARMONIZE NEW YORK DEMAND RESPONSE PROGRAMS WITH ISO-NE** – New England currently allows qualified demand response providers to act as reserves and also permits demand response providers to supply real-time demand reduction when prices reach preset levels; they do not have New York's Day-Ahead Demand Response Program or Emergency Demand Response Program equivalents. Proposals are under development to offer all four programs in NYISO and ISO-NE as part of SMD 2.0.

35. **Projected June 2003 – LAKE ERIE EMERGENCY REDISPATCH (LEER) PROJECT IMPLEMENTATION** - The NERC LEER procedure allows the redispatch of suppliers across regions to alleviate the potential curtailments of transactions due to TLR requests whenever a control area is in an energy short situation. The project requires implementation of operating procedures and billing and settlement process to account for the regional redispatch.

36. **Projected 2003 – NY NEW TRADING HUBS** - Establish trading hubs as requested by market participants to provide locations that would facilitate and enhance trading activity in the New York Market. Detailed project requirements in Reference Document. Working w/ ISO-NE on both.

37. **Projected 2003 – NY TCC OPTIONS FOR EXTERNAL INTERFACES** – TCC Options on external interfaces will allow parties to hedge congestion on long-term transactions. TCC options differ from TCC obligations in that the TCC holder would not pay the NYISO if the value of a TCC option were negative in any hour.

38. **Projected 2003 – OPEN SCHEDULING SYSTEM (OSS) FOR SEAMS ISSUES –** OSS will be implemented as a "one-stop shopping" tool enabling interregional transactions. Specific seams-issues-related features are:
    - Checkout of transaction failures through OSS Phase II - Define processes that will minimize transaction failures due to missing or mismatched data.
    - Ramping - Allow multiple schedule changes per hour.
    - Transaction scheduling via OSS – Defines a single system for managing inter-ISO transactions and allocating interface transfer capability.
    - ATC/TTC posting via OSS - Coordination and consistency with neighboring control areas is required.

    Initial deliverables will occur in 4Q 2002 including one-stop-shop for external transactions between NYISO-PJM. Additional functionality as described above will be deployed in 2003 to support the NYISO RTS development.

39. **Projected 2003 - ESTABLISH REQUIREMENTS FOR EXTERNAL 30-MIN. RESERVES PARTICIPATION IN NYISO** - 1st draft white paper complete Feb. 2002; added as a discussion Item for the NERTO project. Currently being addressed by NPCC TFCO CO-1 WG.

40. **Projected Dec 2003 - NYISO TO IMPLEMENT SMD 2.0 -** SMD 2.0 builds upon SMD 1.0 as well as the 2003 RTS and OSS projects and incorporates a number of "Best Practice" improvements from New York; includes all key features of FERC SMD.

New Issues

Transmission Service Charge Discounting - ability for TOs to discount TSC rates on external interfaces to selectively reduce export charges and encourage use of ties. The software capability exists, however, there does not appear to be any business incentives to exercise discounts.

Improved TTC/ATC Posting – Monthly and yearly posting of TTC/ATC values to support transaction pre-scheduling. Clarify how the ATC values calculated by each ISO should be used to ascertain the ability of the interface to support transactions.

Multiple Transmission Service Charge Invoicing - Companies that conduct business across Control Area borders are faced with receiving a TSC bill from each TO. A single charge should be provided for each transaction to the appropriate parties and revenues allocated to the TOs according to the appropriate usage formulas.

Transmission Interconnection Procedures - Need consistent approach to treating merchant transmission interconnection agreement and procedures among the ISOs.

Controllable Tie Line Scheduling – Need to determine commercial stage modeling, market treatment.

Inter-Control Area Congestion Management/Parallel Flow Management – develop congestion hedges across control area boundaries.

ATTACHMENT IX

NERTO Technology Assessment Phase 1:
Executive Summary
June 7, 2002

NERTO Technology Assessment Phase 1: Executive Summary

Background

In April 2002, ISO New England (ISO-NE) and the New York ISO (NYISO) contracted KEMA Consulting and Rational Software to provide a study of the technical feasibility of creating a common Northeast Energy Market from the merged ISO-NE and NYISO existing markets and control areas. The purpose was to provide ISO-NE and NYISO with a high-level assessment of the readiness of existing and current technology to support this endeavor, and ultimately gain Federal Energy Regulatory Commission (FERC) approval to operate the new market as the Northeast Regional Transmission Organization (RTO). This project was Phase 1 of a multi-phase technology assessment.

Scope

The study included the following tasks:

- Assess at a high-level the feasibility of implementing the NERTO with existing and near-future technologies.
- Identify the critical architecture components that are required for successful implementation given the proposed magnitude of the NERTO.
- Develop a short-term plan to optimize the use of existing applications, infrastructure, and required technology in the period leading up to Day 1 NERTO operations.
- Estimate the cost to develop the NERTO's systems based on a proposed applications components and infrastructure architecture.

Deliverable Documents

The results of the study were packaged into four deliverables:

1. Technology Assessment & Feasibility Recommendation
2. Identification of Architecture Components
3. Short-term Transition Plan
4. High-Level Investment Plan

An early draft of the first three documents was used midway through the project to prepare an interim report to ISO-NE and the NYISO. The feedback on the report was used to reinforce management's key concerns and also served as a preliminary check of the results obtained up to that point.

In parallel with the above efforts, a request for information (RFI) was prepared and issued to three selected vendors. The RFI provided a high-level description of the NERTO requirements and asked the vendors to provide high-level budgetary estimates for implementation of the NERTO applications and infrastructure. These budgetary estimates were used as one of the primary inputs to the High-Level Investment Plan.

Key Study Tasks

KEMA Consulting and Rational Software formed two teams, each made up of people from both companies, and tasked them with obtaining background information on the existing systems and operations practices and requirements for

NERTO operations through an interview process. One team focused on ISO-NE, the other on the NYISO. A common set of questions was prepared to guide interview sessions. The interviews took place over a three-week period, and included sessions with Executive Management, department personnel, and NERTO Task Force members.

The KEMA/Rational teams frequently exchanged notes and held common meetings to share findings and identify information gaps. Preliminary results related to the first three deliverables were issued and circulated for comment.

Using results obtained from the interviews, market analysis, product assessment, industry knowledge, subject matter expertise, and review of past studies, the KEMA/Rational team, through several internal sessions developed the high-level investment plan.

Study Approach

The "clean slate/green field architecture" assumption was made regarding applications and infrastructure for Day 1 NERTO Operations. In this context, green field means application and infrastructure components built from the ground-up, with the condition that it could reasonably be implemented by 2006. For this Phase 1 study, reuse of existing ISO-NE or NYISO systems, or the functions within those systems was not examined in detail, although the Transition Plan contains some information about potential candidates for reuse. Alternatives for reuse of existing functions and systems will be examined in detail during the next phase of technology assessment.

The architecture and associated analysis were organized according to eight primary components:

- Energy Management
- Market Operations
- Market Information
- Billing and Settlement
- Customer Relations Information
- Market Monitoring
- Data Warehouse
- Support Systems

The organization according to the above components was a common thread throughout the four deliverables. In the context of these components, critical demands on computers and infrastructure were identified and assessed with respect to feasibility of NERTO implementation. Also, a green field conceptual architecture diagram was constructed to illustrate logical relationship between the components and the infrastructure.

Significant Conclusions

The state of the technology, in terms of the components required to implement a common Northeast energy market and the underlying infrastructure, is generally such that feasibility of a 12-month procurement stage and a 24-month implementation stage can be confirmed. This conclusion is independent of other factors that may affect the feasibility of achieving these dates, including vendor deliverability, regulatory delays, and organizational resource constraints. There are other technology risks that need to be addressed prior to implementation.

Critical Success Factors

Critical success factors were identified for meeting the 2006 date for Day 1 NERTO operations:

1. Early identification of NERTO leadership to enable timely decisions and accountability.
2. Early acquisition of dedicated resources through staff augmentation with focus on backfilling of critical skills.
3. Implementation of a staged development process where small projects on existing systems are used as a prototype or the basis of new development to minimize risk and gain experience prior to NERTO implementation.
4. Careful selection of vendor-supplied components and integration services coupled with judicious monitoring of vendor development, integration, and testing.
5. Comprehensive testing processes for both vendor developed applications and internally developed applications.
6. Effective change management processes.
7. Preservation of architectural integrity and discipline, with implementation of new technology as appropriate.

Recommendations

Recommendations were provided in four areas: Architecture, Applications, Platforms, and Other

Architecture Recommendations

- Pursue an Enterprise Application Integration (EAI) message bus with non-proprietary messaging protocols.
- Make use of open standards (specifically XML, J2EE, and CIM where possible); for example, XML messaging / data transfer over EAI and CIM as a common information model for power system data.
- Utilize open standards for the final NERTO architecture while utilizing existing, proven technology where possible in the transition.
- Employ clustering of application servers at both sites. Implement redundant communication paths to backup systems. Design applications to enable "hot" backups. Provide synchronized data streams to backup systems.
- Design customer and staff access with security in mind. IT should have offline systems available for development, test, and quality assurance. Data access to production systems should be carefully controlled.
- Plan for and implement a data warehouse and decision support system.
- Form a common domain model, codified by the XML mechanisms and preserved in the data warehouse, to ensure common semantics and access to data.
- Employ the public web where possible, but complement this with a private WAN for sensitive operational information and information that has high performance requirements.

Applications Recommendations

- Substantial improvement in unit commitment technology and performance will be required to meet increased functional and dimensional demands in the same time window allocated for unit commitment both day-ahead and real-time. Vendor demonstration of performance and benchmark testing should be a key element in vendor selection.

- Real-time market clearing and scheduling are judged to be the most demanding in terms of performance and requirements volatility.
- Migrate ISO-NE and the NYISO to a common Northeast portal as an early deliverable of RTO systems. Develop communication/protocol standards over which any portal product could operate. Base the NERTO energy portal applications on these standards.
- Implement one power system network model for the NERTO to eliminate inconsistencies across multiple models. Perform early prototype of regional state estimation options for the NERTO. Allocate adequate resources for initial tuning and ongoing maintenance.
- Adjust Meter Authority rules to shorten settlement adjustment period with customers, trending toward real time.
- Implement customer relations information system.
- Develop capability to setup and run current, past, and future market scenarios. Develop automated mechanisms to support FERC reporting requirements.
- Initiate the definition of the common data model and selection of tools, early in the creation of the NERTO data warehouse.
- Training will be a key element in testing of market and operational systems. Development of a regional simulator requires early attention in the system integration process.
- Do not implement an architecture based on central rules engine at this time.

Platform Recommendations

- Encourage vendors to separate application logic from business rules within their components as precursor to providing rules engine functionality.
- Hardware and software at each site should be identical and redundant. Failover can take place across components or the entire facility. All data and voice links between sites and generators must be redundant, and the mechanism for communications between the sites should be XML over EAI.
- A data warehouse must be implemented to provide consistent, accurate data to end-users without compromising primary data sources.
- Where possible, and in order to insulate the system from technology churn from the major platform vendors, use open standards.

Other Recommendations

- Identify NERTO leadership early to enable timely decisions and accountability.
- Form a NERTO transition team led by key NERTO staff. Develop organization structure and dedicated staff for the development/integration activities.
- There is insufficient staff available for design, development, and testing of the NERTO system. Augment present staff and assign critical resources to project. Obtain necessary skill sets.
- Total elapsed time for the overall schedule appears adequate; however, the portion allocated to development of NERTO applications provides insufficient time for vendors to develop and deliver components.

ATTACHMENT X

ECONOMIC AND RELIABILITY ASSESSMENT OF A NORTHEASTERN RTO

August 23, 2002

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I. Executive Summary

(A) Overview

ISO New England ("ISO-NE") and the New York ISO ("NYISO") conducted an assessment of the effects on the wholesale electricity market and the organizational impacts of forming a proposed Northeast Regional Transmission Organization ("NERTO").

The results of the study will be one factor that the ISO-NE and NYISO Boards of Directors consider when they make a final decision on the formation of NERTO in June 2002. The study identifies the potential costs of implementing NERTO as well as the savings from the market efficiencies and operational consolidation expected to result from NERTO. The market efficiencies include the elimination of barriers between markets and the elimination of export fees charged when electricity travels from one market to another. The study also examines the impacts of adopting a single unit commitment and dispatch. Further, the study evaluates the potential effects of coordinated operation on system reliability and regional air emissions.

The impacts of these market changes are shown for the years 2005 and 2010 both on a region-wide and on an individual ISO basis. The study also examines the intra-regional economic impact of the proposed merger and the sensitivity of the results to particular key assumptions.

(B) Background

In December 1999, FERC issued Order 2000, which encouraged the voluntary formation of Regional Transmission Organizations ("RTOs") to support open access to transmission grids, thereby further promoting the development of competitive electricity markets.

The proposed RTOs are intended to help achieve such policy goals as correcting "seams," which are barriers that impede the flow of power between adjacent areas; adopting a standard market design, with common market rules and procedures, to facilitate trading between areas;

eliminating “export fees” (sometimes called “pancaking”), which are transmission fees for transactions between regions; and creating larger markets.

In early 2002, FERC further clarified its intent by issuing for comment a standard market design working paper that, among other things, emphasized the need to standardize U.S. electricity markets and eliminate transmission fees for transactions between regions.

Ongoing discussions between ISO-NE and NYISO led to a January 2002 agreement jointly to pursue a wide range of wholesale electric power market changes, collaborate closely on market issues with several Canadian provinces and, subject to an economic evaluation, form an RTO in the seven-state Northeast region.

To inform their deliberations, the ISO-NE and NYISO Boards of Directors directed their staffs to conduct an economic and reliability assessment to quantify the impacts of adopting a number of market changes. This study presents the results of that analysis.

(C) Assumptions and Methodologies

The study’s assumptions and data were drawn largely from public sources. Stakeholders provided input on the study methodology, scenarios and assumptions.

The impact of certain market changes on wholesale energy costs was calculated using the General Electric Multi-Area Production Simulation (“GE MAPS” or “MAPS”) model, which simulates the market scheduling and dispatch systems actually used in New York and New England. The benefits of reduced operating reserve requirements and organizational synergies were quantified using separate methodologies.

Throughout this report, the term “single dispatch” is used to mean a single unit commitment and real-time dispatch for the entire seven-state region that employs all of the resources in the region to meet the entire load in the region.

(D) Quantifiable Wholesale Market and Organizational Benefits

The tables below show the impacts in 2005 and 2010 of several key steps:

- Eliminating "seams" between New York and New England by adopting a standard market design, with common scheduling rules and procedures;
- Eliminating transmission export fees; and,
- Adopting a single unit commitment and dispatch.

The tables depict both regional impacts and the individual impacts on New York and New England.

REGIONAL ANALYSIS RESULTS

The results demonstrate that forming a Northeast RTO comprised of New York and New England could result in market efficiencies and reduce wholesale power costs when compared to the current market configuration. Moreover, the creation of an RTO could eliminate export fees and produce the benefits of standardized markets in a fairly short time period.

Table ES - 1 - Summary of Results - Northeast RTO Comprising New York/New England

	Annual Savings in Wholesale Power Costs			
	2005		2010	
NERTO Actions	**$ in Millions**	**% of Wholesale Power Costs**	**$ in Millions**	**% of Wholesale Power Costs**
Eliminate Seams/ Standardize Markets[1]	61	0.8	13	0.2
Eliminate Export Fees	142	2.0	68	0.8
Single Dispatch	7[2]	0.1	33[3]	0.4
Sub-Total Market Benefits	**210**	**2.9**	**114**	**1.4**
Organizational Benefits[4]	10	0.1	36	0.4
Total Benefits	**220**	**3.0**	**150**	**1.8**

The estimated annual regional savings of $220 million achieved in three years (2005) represent about 3 percent of projected wholesale power costs. The annual savings decline to about $150 million, or about 2 percent of total wholesale power costs, in seven years (2010). This occurs because, by 2010, new generation in New York contributes a larger share of total generation, thereby equalizing costs across regions. The installation of additional cost-effective generation in New York, over the long term, should reduce the economic benefit of importing power into New York.

[1] Continuing analysis resulted in an improvement of the hurdle-rate calibration, which brought the simulated power flows between New York and New England and between New York and PJM to within 1% of the actual flows. This refined calibration resulted in a reduction in the projected savings for the elimination of seams and the introduction of standardized markets, but it did not change the results for the elimination of export fees or the introduction of single dispatch. Regional savings from standardized markets were reduced to about $33 million in 2005 and to about $6 million in 2010. See Appendix B for a description of the additional analysis and its results.

[2] Includes $23 million in reserve savings.

[3] Includes $23 million in reserve savings.

[4] The organizational benefits are assumed to be shared equally between New York and New England. This assumption is used throughout the study.

The savings, while significant in absolute dollars, are modest in relation to the projected total annual wholesale power costs[5] in the New York-New England region. As demonstrated in the Sensitivity Analyses presented in the study, these results are sensitive to changes in the input data and assumptions (e.g., fuel prices and the location of new generation).

INTRA-REGIONAL ANALYSIS RESULTS

Table ES - 2 and Table ES - 3 below summarize the intra-regional impacts, in 2005 and 2010, of creating NERTO.

The intra-regional analysis shows that in 2005, New York and New England are affected differently. New York sees a drop in its power costs while New England sees a slight increase. However, in 2010 the difference between New York and New England narrows. In fact, New England sees a small decrease in costs. These differences are attributable to the current and projected mix of generation in the two areas.

In both 2005 and 2010, New York is expected to realize the larger share of benefits from market changes related to an RTO. This is because New York's older, higher-cost generation would be displaced by lower-cost, natural gas-fired generation from New England.

In 2005, with single dispatch, New York would import more than 4 percent of its energy from New England. The New England to New York transfers could cause New England's energy prices to rise slightly in the near term, but these increases would be partially offset by savings from shared operating reserves and organizational consolidation.

By 2010, New England could begin to experience reduced power costs from the formation of NERTO. As new, lower-cost generation is added in New York, there would be

[5] Wholesale power costs for the New York /New England region, based on the marginal-cost fuel-price assumptions used in the study, are estimated to be $7.4 billion in 2005 and $8.4 billion in 2010.

fewer opportunities for lower-cost generators from New England to reduce costs in New York, thus causing prices to equalize between New York and New England. In addition, the benefits of reduced operating reserve requirements and organizational efficiencies could offset any increase in power costs by 2010.

The results could be affected by changes to several key assumptions. For example, a fuel price sensitivity analysis demonstrated that if natural gas and oil prices were to increase by 50 percent above forecast levels, the benefits to New England from NERTO improve by $68 million in 2005 and improve by $109 million in 2010. New York's benefits decrease in this scenario by $17 million in 2005 and $54 million in 2010.[6]

Table ES - 2 - 2005 Summary of Results by Individual ISO

	Annual Savings in Wholesale Power Costs			
	New York		**New England**	
NERTO Actions	**$ in Millions**	**% of Wholesale Power Costs**	**$ in Millions**	**% of Wholesale Power Costs**
Seams Elimination/ Market Standardization	77	1.7	-16	-0.6
Eliminate Export Fees	166	3.6	-24	-0.8
Single Dispatch	34	0.7	-27	-1.0
Sub-Total Market Benefits	**277**[7]	**6.0**	**-67**[8]	**-2.4**
Organizational Benefits	5	0.1	5	0.2
Total Benefits	**282**	**6.1**	**-62**	**-2.2**

[6] In absolute terms, the higher fuel costs scenario results in substantially higher wholesale power costs for both New York and New England. The changes in the allocation of costs and benefits between New York and New England under this scenario are measured against base case fuel cost assumptions.

[7] Includes reserve benefits of $9 million.

[8] Includes reserve benefits of $14 million.

Table ES - 3 - 2010 Summary of Results by Individual ISO

	Annual Savings in Wholesale Power Costs			
	New York		New England	
NERTO Actions	**$ in Millions**	**% of Wholesale Power Costs**	**$ in Millions**	**% of Wholesale Power Costs**
Seams Elimination/ Market Standardization	18	0.4	-5	-0.1
Eliminate Export Fees	94	1.9	-26	-0.8
Single Dispatch	17[9]	0.4	16[10]	0.5
Sub Total Market Benefits	**129**	**2.7**	**-15**	**-0.4**
Organizational Benefits	18	0.4	18	0.5
Total Benefits	**147**	**3.1**	**3**	**0.1**

ORGANIZATIONAL BENEFITS OF NERTO

Table ES - 4 summarizes the organizational efficiencies anticipated from a combination of the two organizations. They are divided into three categories. Initial integration efficiencies are realized when the administration and management of the two organizations are combined into one organization. Operational efficiencies are realized throughout the organization when the two markets are combined into a single dispatch. Capital costs are also reduced under a single organization.

[9] Includes reserve benefits of $9 million.

[10] Includes reserve benefits of $14 million.

Table ES - 4 - Summary of Organizational Benefits[11]

Organizational Efficiency	Annual Benefits (2005) ($ in Millions)	Annual Benefits (2010) ($ in Millions)
Initial Integration Efficiencies (Operating Budget) (2003-2010)	10-15	10-15
Single-Dispatch Efficiencies (Operating Budget) (2006-2010)	0	15-20
Reduction in Capital Costs (2006-2010, After Single Dispatch Implementation)	0	10-30

NERTO IMPLEMENTATION COSTS

Table ES - 5 summarizes the costs associated with NERTO formation. No additional costs are attributed to the NERTO for standardizing markets and eliminating seams because financial commitments to implement Standard Market Design ("SMD") have already been made by ISO-NE and NYISO. The costs to implement NERTO will include legal fees, personnel costs and other start-up costs. The estimated costs of implementing a single dispatch include the software and other development costs associated with creating a single unit commitment and dispatch.

[11] The estimated organizational benefits are shown in the other tables in the executive summary at the lower end of the range.

Table ES - 5 - Summary of RTO Implementation Costs by Action

NERTO Action	Cost ($/millions)	Explanation
Costs of NERTO formation & organizational integration	35-60	
Standardize Markets/Eliminate Seams	N/A	Costs already committed independently of NERTO decision (SMD 1.0 in New England and SMD 2.0 in New York)
Eliminate Export Fees	N/A	Estimated transmission owner revenue losses of $36 million in New York and $14 million in New England must be recovered elsewhere
Single Dispatch	85-160	Cost of single dispatch solution

ANALYSIS OF A THREE-WAY RTO

The analysis also examined the impacts of forming an RTO composed of New England, New York and PJM ("Three-Way RTO"). The results of that analysis are summarized in Table ES - 6 below.

Table ES - 6 - RTO Scope Analysis for NERTO and Three-Way RTO

	Annual Savings in Wholesale Power Costs $/millions		
2005			
Configuration	**New York**	**New England**	**PJM**
Three-Way RTO[12]	367	-28	-136
NERTO[13]	282	-62	-97
2010			
Configuration	**New York**	**New England**	**PJM**
Three-Way RTO[14]	186	23	-144
NERTO[15]	147	3	-107

The benefits to New York and New England of creating NERTO are $220 million in 2005. The benefits to New York, New England and PJM of creating a Three-Way RTO are $203 million in 2005. The Boards of Directors of NYISO and ISO-NE are not currently considering an RTO that combines three areas.

AIR EMISSIONS

The analysis also quantified the tons of SO_2 and NO_X that could be expected to be emitted from the facilities expected to be online in the 2005 Base Case and in each scenario studied. The environmental impacts of RTO formation are small in relation to total emissions.

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[12] Includes reserve benefits of $9 million for New York, $14 million for New England and $10 million for PJM and organizational savings of $5 million for all three regions.

[13] Includes reserve benefits of $9 million for New York and $14 million for New England and organizational benefits of $5 million for both regions.

[14] Includes reserve savings of $9 million for New York, $14 million for New England and $10 million for PJM and organizational savings of $18 million for all three regions.

[15] Includes reserve savings of $9 million for New York and $14 million for New England and organizational savings of $18 million for both regions.

In 2005, creating an RTO increases SO_2 emissions by about 1.3%, while NO_X emissions decline by .4%. In 2010, SO_2 emissions increase by 1.6% in the RTO formation case, while NO_X emissions increase by 1%.

RELIABILITY

In addition to the economic benefits that can be realized through the creation of a NERTO, the reliability requirements of the electric system in the Northeast can be maintained more efficiently due to the benefits of additional resource diversity and reserve sharing.

II. Background

This study arises out of an agreement reached between the ISO-NE and NYISO Boards of Directors in January 2002 (the "January Agreement"). The January Agreement established a plan to institute numerous market improvements, resolve seams issues, standardize market designs, create the conditions for improved market relations with several Canadian Provinces and, subject to an economic evaluation, form an RTO with a single dispatch. This economic evaluation will be among the many factors taken into account by the ISO Boards of Directors to determine whether to proceed with formation of NERTO.

The January Agreement recognizes important similarities and common interests between the New York and New England regions. At the policy level, both regions have required almost total divestiture of generation previously owned by vertically integrated utilities and the rapid development of competitive wholesale and retail markets. In addition, NYISO and ISO-NE are both willing to accommodate the development of independent transmission companies, and each is committed to developing an RTO implementation plan that could resolve many seams issues while working toward a single dispatch. The existing generation inventories in the two regions are complementary, with New England having substantial base-load and intermediate generating capacity and New York having substantial quick-start capacity. The generation diversity between the regions should enable significant savings with regard to operating reserves and single dispatch operation.

The January Agreement also reflects the importance of trade between New York and New England and the nearby Canadian Provinces of Ontario, Quebec and New Brunswick. The Canadian Provinces, New York and New England together comprise the Northeast Power Coordinating Council ("NPCC"), the regional arm of the North American Electric Reliability Council ("NERC"). The Canadian Provinces, New York and New England have a history of substantial trading. The wider region could benefit from harmonizing the markets, reducing or eliminating trading barriers and providing access to additional, diverse energy resources.

III. Analytical Framework

(A) Methodology

The principal measure of benefits used in the study is wholesale power costs, which are estimated by calculating locational marginal prices and multiplying those prices by the amount of load (in MW) that would pay that price.

This study estimates the quantitative benefits and describes some of the qualitative benefits to consumers in the region that would be served by NERTO. The quantifiable benefits are measured in two ways, changes in wholesale power costs and changes in production costs. Wholesale power-cost changes are the primary focus of the report. They are used to facilitate region-specific impact analysis. Changes in bid production costs are reported because GE MAPS minimize those costs in its commitment and dispatch. The study also evaluates expected impacts on air emissions. Finally, the study discusses the reliability impacts of forming NERTO and describes the organizational costs, benefits and impacts on NYISO and ISO-NE.

The study scenarios were designed to assess the impact of a series of changes to the electricity markets in the Northeast region. The study assesses the following market improvements: (1) standardization of market design and elimination of "seams" related impediments to trade; (2) elimination of export fees (transmission charges that hinder efficient trading); and (3) central commitment and dispatch performed by a single organization that has operational control of the entire market. The study results assess changes in wholesale power costs and total production costs for each of the three scenarios.[16]

[16] This study, like others of its type, does not attempt to quantify the effect of changes in wholesale market costs on the retail price of electricity.

The study results are based on (1) the output of a regional production cost model, which includes the bulk transmission system, transmission constraints, generating operating parameters and generation unit emission rate data; (2) the calculation of inter-regional transaction fees based upon existing regional transmission tariffs; and (3) estimated costs and benefits of consolidating organizations and markets, including potential savings in the reserves markets. The study uses a "hurdle rate" approach, similar in concept to the approach employed by ICF in the cost/benefit analysis that it prepared for FERC.

GE MAPS

The principal modeling tool used is the GE MAPS model. The MAPS model is a planning tool widely used throughout the electric power industry. MAPS simulates power system operations and calculates location-specific wholesale power prices based on a detailed hourly representation of expected load, generating unit cost characteristics and availability, and a detailed representation of the regional transmission grid, including constraints. For purposes of this study, it is assumed that each generating unit bids to supply power at its marginal cost. Based on these bids, the model performs a "least cost" economic dispatch of the regional bulk power system under normal operating conditions. A detailed description of the MAPS model appears in Appendix A.

The MAPS model recognizes power flows across a total of 24 zones and sub-zones in the NERTO region, 11 in New York and 13 in New England. The analysis that addresses the Three-Way RTO recognizes 27 zones and sub-zones.[17]

[17] The regional analyses performed by ICF used a total of 9 zones, or sub-regions, in the comparable analysis of Northeast market combinations.

The study evaluates economic benefits for two Base Case time periods 2005 and 2010. The 2005 Base Case was chosen because it is assumed to be the first year that it would be possible to operate a single dispatch. The 2010 Base Case analysis measures changes in benefits over time to evaluate whether the benefits from forming NERTO justify the consolidation and development costs.

The principal assumptions, methodology and scenarios used for MAPS modeling purposes were developed through a collaborative stakeholder process that was initiated in February 2002. The Base Case assumptions are discussed beginning at page 18.

HURDLE RATES AND SCENARIOS

The study methodology uses hurdle rates to quantify the benefits of removing trade barriers between regions and creating a single dispatch. In the study, hurdle rates are financial costs that are added to transactions between regions to model existing export fees and market inefficiencies that hinder inter-regional trade. Hurdle rates were used similarly by ICF in the assessment it prepared for FERC.

The first step in the study analysis was to determine hurdle rates that represent the total of export fees and market inefficiencies in the existing market. The hurdle rates were calibrated using the MAPS model and inter-regional power system and flow data for 2000. A series of MAPS model simulations using different hurdle rates was performed to determine the hurdle rates that resulted in model flows that closely matched actual flows in 2000. The calibrated hurdle rates replicate power flows to within approximately 20% of historical levels between New York and New England, and 5% of historical levels between New York and PJM. Appendix B provides additional information about the calibration process. The calibrated hurdle rates for the Northeast region appear in the "Existing ISO Markets" line in Table 1.

Table 1 - Northeast Region Hurdle Rates for Each RTO Action Scenario ($/MWh)

RTO Action	NY-NE	NE-NY	NY-PJM	PJM-NY
Existing ISO Markets	10.00	11.00	10.00	7.00
Standardized Markets (NY/NE/PJM)	8.00	6.00	9.00	5.00
Standardized Markets No Export Fees (NY/NE/PJM)	2.00	2.00	2.00	2.00
NERTO	-	-	2.00	2.00
Three-Way RTO	-	-	-	-

The calibration of the study model for the year 2000 yields hurdle rates that represent the existing market inefficiencies and export fees at that time. These are the Base Case hurdle rates against which other savings are measured.

In the RTO Action scenario that measures the benefits of standardizing markets and eliminating seams, the study assumes that all transaction inefficiencies are eliminated and the only costs of transactions between regions are the export fees charged by transmission owners and a minimum $2.00 hurdle rate. These are shown in the "Standardized Markets" line on Table 1.

The existing export fees charged by transmission owners include specific regional transmission service, uplift and operating reserve charges. Table 8 at page 29 shows the components of the existing export fees.

Export fees are a trade barrier. The benefits of removing export fees are modeled by lowering the hurdle rates to a minimum $2.00 level, which is consistent with the assumption used by ICF in its assessment for FERC. Within a single RTO region, all market inefficiencies are assumed to be eliminated and hurdle rates are set to zero.

Forming NERTO is likely to reduce the overall cost of maintaining operating reserves for the New York/New England region while preserving reliability. Combining the operation of multiple control areas should allow the larger region to carry fewer operating reserves compared to the reserves currently carried by the individual ISOs. This study assesses the potential cost savings from revised NERTO reserve requirements by considering reductions to the existing New York and New England control area reserve requirements. The combined NERTO reserve requirements are less than the sum of the current requirements in New York and New England, and the study assumes that NERTO could satisfy these reserve requirements at lower cost without decreasing reliability. No reductions in PJM reserve requirements are assumed. The analysis of revised operating reserve requirements and potential cost savings is discussed further in Section IV.

The study also evaluates potential net benefits from consolidating the two existing organizations into one, NERTO. The study estimates the costs associated with implementing the proposed consolidation of organizations and markets and the potential savings from a merger of the two organizations. Information technology systems and software to support the NERTO organization comprise the largest cost category. The analysis of potential organizational cost savings is discussed further in Section V.

(B) Base Case Assumptions

The 2005 Base Case is a one-year assessment of the Northeast markets in 2005 that evaluates both NERTO and the Three-Way RTO scenario. The 2005 Base Case time period selection is based on (1) the expectation that 2005 is the earliest possible date by which a single dispatch could be operating, and (2) the assumption that generation and load forecasts in the selected time frame have a reasonable degree of accuracy. A 2010 Base Case was also developed to assess changes in cost savings over time.

The remainder of this section provides details on the following assumptions used for modeling purposes:

- Generation expansion plans
- Fuel costs
- Generation outage rates
- Emissions modeling
- Demand forecasts
- Transmission expansion plans.

GENERATION EXPANSION PLANS

The study used the most recent published data for installed generating capacity (summer rating) in each region. The installed capacity for New York totals 35,098 MW. For New England, the comparable amount of capacity is 26,336 MW, and for PJM, it is 60,472 MW.

Each region has a multi-stage process for generation siting and a unique set of state and local regulatory approvals that must be obtained before construction of new generation facilities may begin. In addition, each ISO has its own study and approval process for the interconnection of new generation or the expansion or repowering of existing plants. Typically, the amount of proposed new generation capacity in the interconnection study queue exceeds the amount that will actually be built. As of May 1, 2002, the queue for new generation interconnections in the Northeast markets included the following amounts of proposed generation: 10,877 MW for New York, 6,422 MW for New England and 19,142 MW for PJM.

To represent more closely the actual amount of expected new generation in the Base Case scenarios, the study adjusted the amount of capacity in the interconnection study queue for new generation in each region. For New York, the study assumes that any project in construction in 2002 plus 50% of the remaining proposed megawatts associated with projects that have an approved NYISO System Reliability Impact Study ("SRIS") and an accepted New York State Regulatory "Article X" will be built. For 2010, the study assumes that projects in construction in 2002 plus 100% of the remaining proposed megawatts for approved SRIS and accepted Article X projects will be built.

For New England, the study relies on data published in ISO-NE's "Regional Transmission Expansion Plan." The study assumes that facilities currently under construction will be in commercial operation by 2005 and that no further capacity additions will be made before 2010.

For PJM, the study uses the amount of capacity provided by PJM operations staff.

For purposes of the study, no retirements of existing New York, New England or PJM generation are assumed. There is little historical basis for predicting future generation retirements as there have been few significant retirements since the introduction of competitive wholesale markets in New York and New England. To date, no retirements have received final approval in any of the three regions.

The generation capacity assumptions for each region that resulted from the application of the above criteria appear in Table 2.

Table 2 - Cumulative Capacity Additions by Region (MW)

Region	2005	2010
New York	5,978	10,877
New England	6,422	6,422
PJM	16,558	19,142

FUEL COSTS

The study uses the most recent fuel cost projections for natural gas, residual and distillate oil and coal published by the U.S. Energy Information Administration. The projected fuel costs are adjusted for regional natural gas transportation costs. The natural gas transportation cost adder relative to PJM and applied to New York is $0.02/MBTU. The New England natural gas transportation cost adder, which is applied across the six states, is $0.05/MBTU.

The fuel costs used in the study are shown in Table 3.

Table 3 - Projected Fuel Costs ($/MBTU)

Fuel	**2005**	**2010**
Gas	3.29	3.83
Oil		
Residual	3.92	4.40
Distillate	5.48	6.39
Coal	1.26	1.28

GENERATION OUTAGE RATES

The forced and planned outage rates for the six types of generating units used in the study are taken from the national database maintained by NERC. NERC receives outage data voluntarily supplied by owners of generating units throughout the United States, and it analyzes the data, by plant size, for nuclear, coal, oil, gas, gas turbine and combined cycle generating plants. One significant adjustment was made to the national database. Although the NERC database contains historical unit availability for all generating unit types, it contains limited data relating to new combined cycle units installed since 1999. Newer combined cycle units are normally larger and reflect a more complex level of combustion-turbine technology. To capture more accurately the performance of new combined cycle units, this study uses historical unit-availability data on combined cycle units installed in New England since 1999. The data are used to develop an average planned outage rate of 7.6% and an average forced outage rate of 7.6% for the new combined cycle units.

The NERC planned and forced outage rates, as modified, are shown in Table 4.

Table 4 - Generation Outage Rate Assumptions

Unit Type	Size (MW)	Planned Outage Rate	Forced Outage Rate
Nuclear	All	10.0	6.0
Coal	0-99	9.6	4.8
	100-199	10.0	5.7
	200-299	10.6	6.1
	300-399	11.6	8.2
	400-599	11.9	8.0
	600-799	9.8	6.4
	800-999	9.7	5.9
	>=1000	12.0	7.7
Oil	0-99	7.6	4.6
	100-199	10.0	5.6
	200-299	11.0	9.6
	300-399	13.4	6.9
	400-599	13.4	5.4
	600-799	14.4	7.0
	800-999	8.1	5.1
Gas	0-99	6.4	4.2
	100-199	10.2	5.3
	200-299	12.4	3.8
	300-399	15.2	6.7
	400-599	13.2	5.4
	600-799	14.2	6.0
	800-999	10.5	6.1
GT	All	1.8	3.3
CC	All	7.6	7.6

EMISSIONS MODELING

The MAPS model can calculate hourly emission rates of sulfur dioxide (SO_2), carbon dioxide (CO_2) and nitrous oxide (NO_X) for the modeled generating units. The study uses actual emissions data for New York generators and national CEMS data for New England and PJM generators.[18]

The heat rates for new combined-cycle and gas turbine units were assumed to be 6800 MBTU/kWh and 10,000 MBTU/kWh respectively. NO_X emission rates for new gas turbine units were assumed to be 0.0075 lbs/MBTU. Heat and emissions rates for new coal, oil or gas-fired boilers are shown in Table 5.

Table 5 - Default Emissions & Heat Rates

Generator Type	Full Load Heat Rate (MBTU/kWh)				Release Rates (lbs/MBTU)		
	<100MW	100-250 MW	250-500 MW	>500 MW	SO_2	CO_2	NO_x
Coal-Fired Steam Boilers	11,970	10,950	10,800	10,400	1.38	205	0.48
Heavy Oil-Fired Steam Boilers	13,370	11,060	11,990	10,970	0.91	160	0.27
Natural Gas-Fired Steam Boilers	11,860	10,350	9,970	9,340	0.00	119	0.20

The costs of emission credits for NO_X and SO_2 are modeled as variable costs. The costs are reflected in the commitment and dispatch of units, and ultimately in the calculated power cost. Projected emission prices for NO_X and SO_2 were obtained from RDI. The projected prices are shown in Table 6.

[18] New York data from July 1999 NYPP Report; national data (CEMS or continuous emissions monitoring system) maintained by EPA.

Table 6 - Projected Emission Prices ($/ton)

Emission Type	2005	2010
NO_X	$3,170	$3844
SO_2	$263	$343

LOAD FORECASTS

The study relies on the established load-forecasting procedures used by NYISO, ISO-NE and PJM to establish load forecast assumptions.

For New York, Consolidated Edison and the Long Island Power Authority provide peak load forecasts for their service territories with adjustments for municipalities. NYISO uses an economic consulting firm to develop long-term forecasts of peak load for New York. The primary factor in these forecasts is the Gross State Product ("GSP") for New York. The New York GSP is projected to grow at a compounded annual rate of 2.0% between 2001 and 2005, and 2.13% between 2005 and 2010. This level of economic growth resulted in 1.14% compounded annual growth rate in peak demand between 2001 and 2005, and 0.98% between 2005 and 2010.

ISO-NE develops a ten-year annual electricity sales forecast that is disaggregated into hourly energy forecasts and two-year monthly energy and peak demand forecasts for the New England Power Pool ("NEPOOL") region. The ten-year hourly forecast is calibrated to be consistent with the two-year monthly forecasts to arrive at an annual long-term energy and peak-demand forecast.

PJM develops its load forecasts based on the summation of the transmission owners' load forecasts in the PJM region.

The regional load demand forecasts used in this study are shown in Table 7.

Table 7 - Regional Load Demand Forecasts

Time Period	New York	New England	PJM
2005			
Annual Energy (GWh)	170,955	131,903	286,914
Peak Demand (MW)	31,755	25,433	56,365
2010			
Annual Energy (GWh)	179,346	142,131	306,873
Peak Demand (MW)	33,346	27,269	60,645

TRANSMISSION EXPANSION PLANS

In each region, assumptions regarding transmission expansion plans were determined considering local regulatory or ISO approvals. For New York, the study considered those transmission expansion project that have an accepted New York State Article 7 filing. These projects are identified in Appendix D.

For New England, the 345 kV transmission expansion proposed for Southwest Connecticut was assumed to be in place for 2010. Portions of the Southwest Connecticut expansion were assumed to be in place by 2005.

(C) Study Scenarios

The study analyzes three market-improvement scenarios. The scenarios are intended to follow the progression of market changes anticipated in the Northeast over the next three years. The three scenarios analyzed are:

1. Standardization of market rules and elimination of inter-regional trade impediments (“seams”).
2. Elimination of export fees.
3. Establishment of a single unit commitment and dispatch process across the RTO.

The scenarios were chosen for the following reasons:

- Significant improvements to the existing Northeast markets, including standardization of market features and the eradication of cross-border trading impediments ("seams"), and elimination of export fees can be realized in the near term. Significant near-term market improvements are already being implemented, and others are planned. Certain additional market improvements are likely to occur only in the context of consolidated markets and organizations.

- Significant time and effort are required to form a single day-ahead and real-time Northeast market with centralized unit commitment and dispatch by one organization. The study assumes a single dispatch could be implemented by 2005.

Each of the study scenarios is evaluated for both a NERTO and a Three-Way RTO combination in 2005 and 2010. Results are calculated for the Northeast region and for the New York, New England and PJM sub-regions.

MARKET STANDARDIZATION AND SEAMS ISSUES

The two broad categories of market standardization and inter-regional trade improvements expected to take place prior to 2005 are the elimination of differences in significant market rules and the harmonization of scheduling practices across the existing markets. The effort to implement inter-regional market improvements takes place in the context of a number of initiatives, including (1) the August 1999 Inter-regional Coordination Agreement among the Northeast ISOs (the "MOU" process); (2) the identification of "Best Practices" in New York, New England and PJM during the RTO mediation process initiated by FERC in 2001; (3) the January Agreement between NYISO and ISO-NE; and (4) the March 2002 Inter-regional Coordination Agreement between NYISO and PJM. For purposes of this study, initiatives that take effect anytime after January 2001 are attributed to the "Market Standardization" scenario.

This scenario assumes that some portion of the difference in wholesale electricity prices in the New York, New England and PJM markets results from inefficiencies related to market differences and scheduling practices. Quantitatively, the hurdle rate used to determine the market value of eliminating these inefficiencies is derived by reducing the existing hurdle rate by the sum of the relevant inter-regional transaction fees and the $2.00/MWh minimum hurdle rate. A model run is then performed using the lower hurdle rate and compared to the Base Case to determine the impact of market standardization and the elimination of "seams."

Some examples of market standardization and scheduling improvements that have recently been implemented or will be implemented in the near term include:

- The elimination of the "Short Notice Transaction Rule" that previously limited exports from New England to New York. This rule change became effective on May 1, 2002. The rule change allows certain scheduled energy sales from New England to New York that were previously restricted to take place based on the market value of the energy in New York and New England.

- The adoption of an Installed Capacity market in New England that is based on the existing product in New York.

- The establishment of an "Open Scheduling System" that will allow the ISOs to manage ramp constraints between the regions in a more coordinated and economically efficient manner.

EXPORT FEES (INTER-REGIONAL TRANSACTION COSTS)

One of the benefits of creating an RTO is the elimination of export fees, i.e. certain transmission-related fees levied on transactions between regions. The export fees are in place now and cause transactions to be uneconomic that would be economic if the fees were eliminated. There are other transmission-related fees that affect interregional transactions. These include uplift, ancillary services and losses. The export fees and other transaction fees used in the study are shown in Table 8.

Table 8 - Export Fees for 2001 ($/MWh)

Fee Type	NY to PJM	PJM to NY	NY to NE	NE to NY
Transmission Out-service[19]	**5.13**	**2.43**	**4.28**	**2.40**
Other Charges[20]	**1.87**	**0.57**	**1.72**	**1.60**
Total Fees[21]	**7.00**	**3.00**	**6.00**	**4.00**

Currently, export fees are built into the cost of power traded between regions. New England transmission owners receive export fees for sales to New York while New York transmission owners receive export fees for sales to New England. The study results show a decrease in wholesale power costs and bid production costs when export fees are removed. Removing export fees makes it less expensive to exchange power between regions, thereby leading to a more efficient dispatch and lower costs.

Since the study does not treat transmission revenues explicitly, it assumes that any revenues lost through the elimination of export fees will be recovered by transmission owners in some other way. Based on 2000/2001 operating data, transmission owner revenues associated with export fees were approximately $36 million in New York and $14 million in New England.

The inter-regional transaction fees charged by transmission owners are 36% to 70% of the Base Case hurdle rates. After seams are eliminated and market rules are standardized, the

[19] The data for New York are based on the Transmission Service Charge Calculator, which calculates transmission charges across interfaces on a flow-weighted basis by transmission owner. The New England data are based on the rates for Through or Out Service under the NEPOOL Open Access Transmission Tariff. The PJM data are based on the applicable provisions of the PJM Open Access Transmission Tariff.

[20] The exact components of the "Other Charges" vary by region, but the charges generally comprise ancillary services, including scheduling and dispatching services, cost of operating reserves and both energy and transmission uplift charges.

[21] Because the "Other Charges" components generally vary from month to month, the totals were rounded to the nearest dollar value, with increases or decreases attributed to the "Other Charges" component.

study assumes that export fees between regions are eliminated when the regions are combined into an RTO. This assumption is consistent with the ICF assessment prepared for FERC, and it is reasonable because other inter-regional transaction charges are relatively small, and these charges may be offset by efficiency gains in any event.

SINGLE DISPATCH

In this study scenario, NERTO conducts a single day-ahead and real-time unit commitment and dispatch process for New York and New England. Local reserve requirements and current levels of regional operating reserves would be satisfied in the day-ahead commitment. As described below, a separate methodology is used to estimate the economic benefits of reduced operating reserves facilitated by the creation of NERTO. The single-dispatch scenario assumes that markets are standardized and seams eliminated between PJM and NERTO. The only export fees between PJM and NERTO are reflected in the minimum $2.00 hurdle rate.

(D) Sensitivity Analyses

The following sensitivity analyses were performed for one or more of the Base Case scenarios.

<u>Increased Trade with Canada</u>

- Energy trade availability with the Canadian Provinces is assumed to increase by 25% in 2005 and to remain at that level in 2010. Availability of additional imports is modeled as 1,500 MW capability over the Phase II intertie between Hydro-Quebec and New England and 1,500 MW capability over the Chateauguay intertie between Hydro-Quebec and New York.

<u>Increased Trade with Midwest</u>

- Energy trade availability with the Midwest is assumed to increase by 25% in 2005 and remain at that level in 2010. Availability of additional imports are modeled as a 25% increase in available capability at the PJM - ECAR interconnection.

High Fuel Prices

- Natural gas and oil prices are assumed to increase by 50% in 2005 and to remain at that level in 2010.

Decreased Capacity Additions

- Assumes that only 50% of the expected 2010 capacity expansions in the New York and PJM regions are available.

Increased Transfer Capability

- Total transfer capability between New York and New England, and between New York and PJM, is assumed to increase by 10% in 2010.

(E) Emissions Modeling

Power plant emissions are expected to change as impediments to trade across the existing markets are reduced. The study quantifies the projected impact of NERTO formation on power plant emission levels in the region. The MAPS model measures the tons of SO_2 and NO_X that may be emitted from the facilities expected to be on-line in 2005 and in each study scenario.

(F) Production Cost Benefits

In addition to analyzing wholesale power costs, the study also measures market efficiency in terms of the total production costs of resources required to meet load in each scenario. The change in total production costs is calculated by the MAPS model. The estimated production cost savings take into account changes in start-up costs, minimum load operating costs and incremental energy costs, including variable operations and maintenance, fuel and emissions costs. Changes in total production costs will be smaller than changes in wholesale energy prices.

IV. Quantitative Results

This section of the study presents the quantitative results of the analyses that were performed. The results identify benefits in terms of changes in wholesale power costs and production costs. For each case, both the expected cost savings and changes in regional power flows are shown. The results in terms of wholesale power costs are presented first, followed by the production-cost results. Within each section, the base case results are presented first and are followed by the results of the sensitivity analyses related to the base case. Finally, the results also present expected changes in air emissions.

(A) Wholesale Power Cost Analysis

2005 AND 2010 BASE CASE SUMMARY

Table 9 summarizes the projected regional savings under the 2005 Base Case. The results show the projected savings associated with taking the indicated RTO Actions. The percentage savings are calculated based on projected power costs in 2005 without any RTO Actions. The annual savings in 2005 are about $220 million representing about 3% percent of projected wholesale power costs. In the 2010 Base Case, the annual savings decrease to $150 million, or about 2% of total wholesale power costs. This decrease occurs because, by 2010, new generation in New York can provide a larger share of low-cost generation in the region, thereby reducing the economic benefit of importing power to New York.

Table 9 - 2005 & 2010 Base Case Summary of Results

	Incremental Savings in Wholesale Power Costs			
	2005		**2010**	
RTO Actions	**$/millions**	**% of Wholesale Power Costs**	**$/millions**	**% of Wholesale Power Costs**
Market Standardization	61	0.8	13	0.2
Eliminate Export Fees	142	2.0	68	0.8
Single Dispatch*	7	0.1	33	0.4
Total**	220	2.9	150	1.8

* Includes reserve savings of $23 million.

** Includes organizational savings of $10 million and $35 million for 2005 and 2010, respectively.

The study results also show that standardizing markets and eliminating export fees provide significant savings in both 2005 and 2010. In 2005, eliminating export fees accounts for nearly 70 percent of the savings while in 2010 it accounts for about 45 percent of the savings. Standardization of markets and the elimination of export fees provide a large proportion of the savings in all cases of sensitivity analysis. The reason for this can be seen in Table 11 below, which shows the power flows between the ISO sub-regions for the 2005 Base Case. The elimination of export fees alone causes average hourly flows from New England to New York to increase from 158 MW/hour to 659 MW/hour and from 600 MW/hour to 1,187 MW/hour for flows from PJM to New York.[22]

[22] The maximum flows between New York and New England are about 1,700 MW/hour and 3,000 MW/hour between New York and PJM.

2005 BASE CASE BY ISO

Table 10 summarizes the distribution of wholesale power costs savings between the ISO sub-regions for each of the RTO Actions using the 2005 Base Case assumptions. The table shows the incremental savings due to each RTO Action. The results show savings in New York, with a loss in New England. As shown in Table 12, New York continues to receive benefits in the 2010 Base Case and New England losses are eliminated.

Table 11 shows that the incremental savings in wholesale power costs are strongly coupled to changes in inter-regional transfers. The table shows the cumulative impact on flows of each RTO Action. As each NERTO market improvement is implemented, higher levels of transfers occur from New England to New York reflecting the use of transmission capability to make optimal use of generation resources. Under NERTO single-dispatch operation, hourly average energy transfers from New England to New York are over 850 MW, which is about one-half of the maximum possible flow.[23] These projected inter-regional transfers result from the displacement of New York's older, higher cost generation with low-cost natural gas-fired generation in New England.

[23] Under NERTO single dispatch operation, the New England to New York AC inter-tie transfer capabilities are assumed to increase by 5% from 1,400 MW to 1,470 MW to reflect improved operating and scheduling limits.

Table 10 - 2005 Base Case by ISO - Incremental Savings

	Incremental Savings in Wholesale Power Costs ($/millions)			
	NY		NE	
RTO Actions	$/millions	% of Wholesale Power Costs	$/millions	% of Wholesale Power Costs
Market Standardization	77	1.7	-16	-0.6
Eliminate Export Fees	166	3.6	-24	-0.8
Single Dispatch*	34	0.7	-27	-1.0
Total**	282	6.1	-62	-2.2

* Includes reserve savings of $9 million for New York and $14 million for New England.

** Includes organizational savings of $5 million each for New York and New England.

Table 11 - 2005 Base Case by ISO - Inter-Regional Transfers

	Inter-Regional Transfers					
	NE to NY Transfers			PJM to NY Transfers		
RTO Actions	Average MW	MW Limit*	Hours Limited	Average MW	MW Limit**	Hours Limited
Existing Hurdle Rates	22	1700	0	305	3100	0
Market Standardization	158	1700	28	600	3100	0
Eliminate Export Fees	659	1700	1296	1187	3100	0
Single Dispatch	858	1770	2602	1076	3100	0

* Includes 300 MW HVdc intertie capability between New York and New England.

** Includes 600 MW HVdc intertie capability between New York and PJM.

2010 BASE CASE BY ISO

As shown in Table 12 and Table 13, the 2010 Base Case results show that projected annual savings from forming NERTO decrease from about $220 million in 2005 to $150 million in 2010. This occurs because more generation throughout the region is coming from new, efficient generating units being added in New York and, to some extent, PJM. No additional generation is forecast to be added in New England between 2005 and 2010. These changes in generation resources cause prices in New York to decrease and reduce the sale of low-cost power from New England to New York. Indeed, average hourly flows change from 858 MW from New England to New York in 2005 to an average of 6 MW in the opposite direction in 2010.

These changes in regional power supply also change the small losses experienced by New England under NERTO into a small benefit, as additional capacity is added in New York and no new capacity is added in New England. In 2010, New York continues to see benefits from NERTO formation, but smaller benefits than projected for 2005.

Table 12 - 2010 Base Case by ISO - Incremental Savings

	Incremental Savings in Wholesale Power Costs ($/millions)			
	NY		NE	
RTO Actions	$/millions	% of Wholesale Power Costs	$/millions	% of Wholesale Power Costs
Market Standardization	18	0.4	-5	-0.1
Eliminate Export fees	94	1.9	-26	-0.8
Single Dispatch*	26	0.5	20	0.4
Total**	147	3.0	3	0.1

* Includes reserve savings of $9 million for New York and $14 million for New England.

****** Includes organizational savings of $18 million each for New York and New England.

Table 13 - 2010 Base Case by ISO - Inter-Regional Transfers

	Inter-Regional Transfers					
	NE to NY Transfers			PJM to NY Transfers		
RTO Actions	Average MW	MW Limit*	Hours Limited	Average MW	MW Limit**	Hours Limited
Existing Hurdle Rates	1	1700	0	161	3100	0
Market Standardization	29	1700	2	324	3100	0
Eliminate Export Fees	99	1700	150	658	3100	0
Single Dispatch	-6	1770	1876	684	3100	0

* Includes 300 MW HVdc intertie capability between New York and New England.

** Includes 600 MW HVdc intertie capability between New York and PJM.

2005 SENSITIVITY ANALYSES

The 2005 Sensitivity Analysis results are summarized in Table 14. The sensitivity analyses are intended to measure whether the benefits of NERTO formation change significantly under alternative assumptions about future conditions. Generally, the results show that for the entire region there are only small changes in benefits for different sensitivity assumptions, but the sub-regional impacts do change significantly under some scenarios. For example, under the "High Gas Fuel Prices" scenario for 2005, the overall regional benefits change by only $12 million, but the benefits to New England change from -$62 million to $23 million. The same "High Gas Fuel Price" scenario produces similar results for New England in 2010.

The table shows the savings in the 2005 Base Case and the change in savings resulting from each of the sensitivity cases. For example, the "Improved Canadian Trade" scenario results in an additional $11million in savings for New York and an additional $8 million savings for New England, resulting in cumulative benefits of $ 293 million for New York and -$54 million for New England. The incremental savings in wholesale power costs associated with the sensitivity cases are explained by the changes in inter-regional transfers shown in Table 15.

For the "Improved Canadian Trade" scenario, a 25% increase in available import capability at the New York - Chateauguay and the New England - Phase II interconnections with Quebec was assumed. Significant additional benefits, totaling $19 million of wholesale energy cost savings, were found in the "Improved Canadian Trade" scenario.

For the "High Gas Fuel Prices" and the "High Gas/Oil Fuel Prices" scenarios, an increase in New England benefits of $85 million and $68 million, respectively, result from significant energy transfers from New York to New England.

The "Low Capacity Expansion" scenario assumes that only 50% of the expected 2010 capacity expansions in the New York and PJM regions are built. This results in higher prices in

New England as power flows out of New England to meet demand that would otherwise be supplied by the new generation.

Table 14 - 2005 Sensitivity Analyses - Incremental Savings

	Incremental Savings in Wholesale Power Costs ($/millions)			
	NY		NE	
Scenarios	**$/millions**	**% of Wholesale Power Costs**	**$/millions**	**% of Wholesale Power Costs**
Total Base Case	282	6.0	-62	-2.4
Improved Canadian Trade	11	0.2	8	0.3
High Gas Fuel Prices	-73	-1.6	85	3.1
High Gas/Oil Fuel Prices	-17	-0.4	68	2.5
Low Capacity Expansion	6	0.1	-23	-0.8

Table 15 - 2005 Sensitivity Analyses - Inter-Regional Transfers

	Inter-Regional Transfers					
	NE to NY Transfers			PJM to NY Transfers		
Scenarios	Average MW	MW Limit*	Hours Limited	Average MW	MW Limit**	Hours Limited
NERTO Single Dispatch	858	1770	2602	1076	3100	0
Improved Canadian Trade	861	1770	892	1044	3100	0
High Gas Fuel Prices	167	1770	1868	1316	3100	0
High Gas/Oil Fuel Prices	445	1770	1170	1303	3100	0
Low Capacity Expansion	1040	1770	2864	786	3100	0

* Includes 300 MW HVdc intertie capability between New York and New England.

** Includes 600 MW HVdc intertie capability between New York and PJM.

2010 Sensitivity Analyses

For the 2010 Sensitivity Analyses, incremental savings in wholesale power costs are again strongly coupled to the changes in inter-regional transfers as indicated in Table 16 and Table 17. The “Improved Canadian Trade” scenario results in additional annual savings of $45 million in 2010.

For the “High Gas Fuel Prices” and the “High Gas/Oil Fuel Prices” scenarios, New England benefits of $75 million and $109 million, respectively, result from significant energy transfers from New York to New England. In the “High Gas Fuel Prices” scenario, there are large energy transfers from New York to New England with flows between the two neighboring regions averaging over 611 MW/hour.

In the “Increased Transfer Capability” scenario, the New England to New York AC inter-tie and the PJM to New York AC inter-tie transfer capabilities are assumed to increase by 10%

from 1,400 MW to 1,540 MW and from 2,500 MW to 2,750 MW respectively to reflect assumed transmission system improvements between regions. No measurable benefits, in terms of wholesale energy cost savings, were found in the "Increased Transfer Capability" scenario. This, one of the more interesting results of the study, suggests that additional transfer capability between the sub-regions is not needed given the current mix of generation resources.

Table 16 - 2010 Sensitivity Analyses - Incremental Savings

	Incremental Savings in Wholesale Power Costs ($/millions)			
	NY		**NE**	
Scenarios	**$/millions**	**% of Wholesale Power Costs**	**$/millions**	**% of Wholesale Power Costs**
Total Base Case	147	3.0	3	0.1
Improved Canadian Trade	22	0.2	23	0.3
High Gas Fuel Prices	-78	-1.6	75	2.1
High Gas/Oil Fuel Prices	-54	-0.4	109	2.5
Increased Transfer Capability	-1	0	0	0

Table 17 - 2010 Sensitivity Analyses - Inter-Regional Transfers

	Inter-Regional Transfers					
	NE to NY Transfers			PJM to NY Transfers		
Scenarios	Average MW	MW Limit*	Hours Limited	Average MW	MW Limit**	Hours Limited
NERTO Single Dispatch	-6	1770	1876	684	3100	0
Improved Canadian Trade	3	1770	1914	654	3100	0
High Gas Fuel Prices	-611	1770	2952	967	3100	6
High Gas/Oil Fuel Prices	-461	1770	1952	983	3100	8
Increased Transfer Capability	-17	1840	1692	686	3350	0

* Includes 300 MW HVdc intertie capability between New York and New England.

** Includes 600 MW HVdc intertie capability between New York and PJM.

2005 AND 2010 RTO SCOPE BASE CASES

Table 18 summarizes the projected savings in 2005 for each region from forming NERTO or a Three-Way RTO. Overall, the results show that the formation of NERTO captures a substantial portion of the benefits that would result from a Three-Way RTO. Comparing the results for New York and New England under NERTO and the results for NY/NE/PJM under a Three-Way RTO, the savings to New York/New England under NERTO are $220 million in 2005 and the savings for NY/NE/PJM under a Three-Way RTO are $203 million. However, if the results for PJM are added to the New York/New England results under NERTO, the savings under NERTO drop to $123 million for the NY/NE/PJM region.

Table 18 - 2005 RTO Scope Base Case - Incremental Savings

	Savings in Wholesale Power Costs ($/millions)				
Configuration	**New York**	**New England**	**PJM**	**NY/NE Region**	**NY/NE/PJM Region**
Three-Way RTO*	367	-28	-136	339	203
NERTO**	282	-62	-97	220	123

* Includes reserve benefits of $9 million for New York, $14 million for New England and $10 million for PJM and organizational savings of $5 million for each of the three regions.

** Includes reserve benefits of $9 million for New York and $14 million for New England and organizational savings of $5M for both regions.

Table 19 - 2005 RTO Scope Base Case - Inter-Regional Transfers

	Inter-Regional Transfers					
	NE to NY Transfers			PJM to NY Transfers		
Scenarios	**Average MW**	**MW Limit***	**Hours Limited**	**Average MW**	**MW Limit****	**Hours Limited**
Three-Way RTO*	736	1770	2490	1688	3225	0
NERTO**	858	1770	2602	1076	3100	0

* Includes 300 MW HVdc intertie capability between New York and New England.

** Includes 600 MW HVdc intertie capability between New York and PJM.

Table 20 shows that by 2010 the annual savings from both NERTO and a Three-Way RTO decrease noticeably from those in 2005. This occurs because, by 2010, new generation in New York constitutes a larger share of the low-cost generation in the region, thereby reducing the economic benefit of importing power into New York.

Table 20 - 2010 RTO Scope Base Case - Incremental Savings

	Incremental Savings in Wholesale Power Costs ($/millions)				
Configuration	**NY**	**NE**	**PJM**	**NY/NE Region**	**NY/NE/PJM Region**
Three-Way RTO*	186	23	-144	209	65
NERTO**	147	3	-107	150	43

* Includes reserve savings of $9 million for New York, $14 million for New England and $10 million for PJM and organizational savings of $18 million for all three regions.

** Includes reserve savings of $9 million for New York and $14 million for New England and organizational savings of $18 million for both regions.

Table 21 - 2010 RTO Scope Base Case - Inter-Regional Transfers

	Inter-Regional Transfers					
	NE to NY Transfers			PJM to NY Transfers		
Scenarios	**Average MW**	**MW Limit***	**Hours Limited**	**Average MW**	**MW Limit****	**Hours Limited**
Three-Way RTO*	-93	1770	2172	1138	3225	0
NERTO**	-6	1770	1876	684	3100	0

* Includes 300 MW HVdc intertie capability between New York and New England.

** Includes 600 MW HVdc intertie capability between New York and PJM.

2005 RTO Scope Sensitivity Analyses

For the 2005 RTO Scope Sensitivity Analyses, incremental savings in wholesale power costs are again strongly coupled to the changes in inter-regional transfers as indicated in Table 22 and Table 23. For the “Improved Canadian Trade” scenario, a 25% increase in available import capability at the New York - Chateauguay and the New England - Phase II interconnections with Quebec was assumed. In the “Improved Midwest Trade” scenario, a 25% increase in imports was assumed to be available at the PJM - ECAR interconnections. For the “High Gas Fuel Prices” and the “High Gas/Oil Fuel Prices” scenarios, New England benefits of

$78 million and $66 million, respectively, result from significant energy transfers from New York to New England. The "Low Capacity Expansion" scenario assumes that only 50% of the expected 2010 capacity expansion will be available in the New York and PJM regions. There are large energy transfers from New England to New York with transfers averaging over 950 MW/hour under the "Low Capacity Expansion" scenario.

Table 22 - 2005 RTO Scope Sensitivity Analysis - Incremental Savings

	Incremental Savings in Wholesale Power Costs ($/millions)			
Configuration	**NY**	**NE**	**PJM**	**Total**
Three-Way RTO*	367	-28	-136	203
Improved Canadian Trade	8	9	5	22
Improved Midwest Trade	14	5	42	60
High Gas Fuel Prices	-95	78	8	-9
High Gas/Oil Fuel Prices	-32	66	-61	-27
Low Capacity Expansion	-19	-43	47	-15

* Includes reserve savings of $9 million for New York, $14 million for New England and $10 million for PJM.

Table 23 - 2005 RTO Scope Sensitivity Analysis - Inter-Regional Transfers

	Inter-Regional Transfers					
	NE to NY Transfers			PJM to NY Transfers		
Scenarios	**Average MW**	**MW Limit***	**Hours Limited**	**Average MW**	**MW Limit****	**Hours Limited**
Three-Way RTO*	736	1770	2490	1688	3225	0
Improved Canadian Trade	744	1770	2480	1649	3225	0
Improved Midwest Trade	713	1770	2434	1704	3225	0
High Gas Fuel Prices	-8	1770	1740	1812	3225	0
High Gas/Oil Fuel Prices	272	1770	892	1771	3225	0
Low Capacity Expansion	951	1770	2776	1351	3225	0

* Includes 300 MW HVdc intertie capability between New York and New England.

** Includes 600 MW HVdc intertie capability between New York and PJM.

For the 2010 RTO Scope Sensitivity Analyses, incremental savings in wholesale power costs are again strongly coupled to changes in inter-regional transfers as indicated in Table 24 and Table 25. As in the 2005 RTO Scope Base Case, for the “Improved Canadian Trade” scenario, a 25% increase in import capability at the New York - Chateauguay and the New England - Phase II interconnections with Quebec was assumed. In the “Improved Midwest Trade” scenario, a 25% increase in imports was assumed to be available at the PJM - ECAR interconnections. For the “High Gas Fuel Prices” and the “High Gas/Oil Fuel Prices” scenarios, New England benefits of $81 million and $123 million respectively result from significant energy transfers from New York to New England. Energy transfers from New York to New England total over 720 MW/hour in the “High Gas Fuel Prices” scenario. In the “Increased Transfer Capability” scenario the New England to New York AC inter-tie and the PJM to New

York AC inter-tie transfer capabilities are assumed to be increased by 10% from 1,400 MW to 1,540 MW and from 2,500 MW to 2,750 MW respectively to reflect transmission system improvements between regions. No measurable benefits, in terms of wholesale cost savings, were found in the “Increased Transfer Capability” scenario.

Table 24 - 2010 RTO Scope Sensitivity Analysis - Incremental Savings

	Incremental Savings in Wholesale Power Costs ($/millions)			
Scenario	**NY**	**NE**	**PJM**	**Total**
Three-Way RTO*	186	23	-144	65
Improved Canadian Trade	18	20	12	51
Improved Midwest Trade	16	8	40	64
High Gas Fuel Prices	-69	81	-36	-24
High Gas/Oil Fuel Prices	-36	123	-98	-9
Increased Transfer Capability	-1	1	-1	-1

* Includes reserve Savings of $9 million for New York, $14 million for New England, and $10 million for PJM

Table 25 - 2010 RTO Scope Sensitivity Analysis - Inter-Regional Transfers

	Inter-Regional Transfers					
	NE to NY Transfers			PJM to NY Transfers		
Scenarios	**Average MW**	**MW Limit***	**Hours Limited**	**Average MW**	**MW Limit****	**Hours Limited**
Three-Way RTO*	-93	1770	2172	1138	3225	0
Improved Canadian Trade	-76	1770	2160	1093	3225	0
Improved Midwest Trade	-117	1770	2266	1172	3225	0
High Gas Fuel Prices	-727	1770	3292	1343	3225	0
High Gas/Oil Fuel Prices	-587	1770	2308	1339	3225	8
Increased Transfer Capability	-110	1840	1960	1143	3350	0

* Includes 300 MW HVdc intertie capability between New York and New England.

** Includes 600 MW HVdc intertie capability between New York and PJM.

(B) Production Cost Analysis

BASE CASE RESULTS

The estimated production cost savings are summarized for each of the base scenarios as shown in Table 26. The estimated production cost savings shown in the table are calculated only for the combined New York, New England and PJM region as a whole, not for sub-regions. Allocating production costs to a sub-region does not identify the region of the load the generation may be supplying. It could be supplying load in any of the regions studied or in other adjacent regions.

Table 26 - Production Cost Savings - Base Scenario ($/millions)

Scenario	2005	2010
Base Case	**NY/NE/PJM**	**NY/NE/PJM**
SMD & Seams Fixed (Three Separate ISOs)	**+$35**	**+$20**
SMD, Seams Fixed & Export Fees Eliminated (Three Separate ISOs)	**+$90**	**+$55**
NERTO Single Dispatch	**+$96**	**+$62**
Improved Canadian Trade NERTO	**+$3**	**+$7**
Improved Midwest Trade NERTO	**+$20**	**+$25**
Increased Inter-Regional Transfer Capability NERTO	**$0**	**$0**
Three-Way RTO Single Dispatch	**+$101**	**+$71**
Improved Canadian Trade Three-Way RTO	**+$5**	**+$7**
Improved Midwest Trade Three-Way RTO	**+$20**	**+$26**
Increased Inter-Regional Transfer Capability Three-Way RTO	**$0**	**$0**

SENSITIVITY ANALYSES

Two sensitivity analyses of the production cost scenarios were conducted.

Table 27 shows the estimated production cost savings for the entire Northeast region under the "High Gas Fuel Prices" scenario.

Table 28 shows the estimated production cost savings for the entire Northeast region under the "Low Capacity Expansion" scenario. The "Low Capacity Expansion" scenario reflects only 50% of the expected 2010 capacity expansion otherwise expected to be available in the New York and PJM regions.

Table 27 - Production Cost Savings - High Gas ($/millions)

Scenario	2005	2010
High Natural Gas Fuel Prices	**NY/NE/PJM**	**NY/NE/PJM**
SMD & Seams Fixed (Three Separate ISOs)	**+$21**	**+$17**
SMD, Seams Fixed & Export Fees Eliminated (Three Separate ISOs)	**+$49**	**+$55**
NERTO Single Dispatch	**+$52**	**+$57**
Three-Way RTO Single Dispatch	**+$49**	**+$61**

Table 28 - Production Cost Savings - Low Capacity Expansion ($/millions)

Scenario	2005
Low Capacity Expansion Scenario	**NY/NE/PJM**
SMD & Seams Fixed (Three Separate ISOs)	**+$36**
SMD, Seams Fixed & Export Fees Eliminated (Three Separate ISOs)	**+$86**
NERTO (Single Dispatch)	**+$90**
Three-Way RTO (Single Dispatch)	**+$98**

(C) Emissions Changes

The MAPS model indicates that reducing barriers to trade and forming any Northeast RTO increases the emissions of SO_2 from all generating facilities expected to be on line in 2005. The Three-Way RTO results in a larger increase in tons of SO_2 emitted than NERTO does due to increased production from coal-fired generation in PJM. The MAPS model revealed no significant change in tons of NO_X emitted, over a 2005 base case, for any of the scenarios studied.

The Three-Way RTO combination causes an increase of approximately 22,515 tons (1.7%) of SO_2 emitted from all generating facilities in the region in 2005. The formation of NERTO produces a slightly lower increase of 17,274 tons of SO_2 emitted (1.3%).

The MAPS model shows, on the other hand, that none of the changes in trade or organizational structure studied produces materially different impacts with regard to NO_X emissions. In 2005, elimination of trade barriers and formation of NERTO reduces NO_X

emissions by 0.44% and 0.37%, respectively, while the Three-Way RTO increases NO_X emissions by 0.4%.

V. Reliability Analysis

An electric power system must satisfy system load requirements at a high level of continuity and quality. The ability to deliver electricity continuously at satisfactory quality levels is defined in terms of reliability criteria, which are best understood in the context of two basic features, adequacy and security.

Adequacy is a static measure of the ability of the facilities within the electric system to satisfy total electrical demand. These facilities include both generating facilities required to produce sufficient energy to meet load requirements and the transmission and distribution facilities required to transport energy to load. An electric power system satisfies an adequacy requirement if it has sufficient installed capacity to meet its projected peak load plus a reserve requirement.

Security relates to the ability of the system to respond to unexpected disturbances or contingencies, such as the loss of major generation and transmission facilities. Power systems are designed to withstand the loss of major facilities without having to disconnect customers.

Reliability standards and criteria are determined at the national, regional and local level. At the national level, ISO-NE and the NYISO are members of NERC and NPCC. The NPCC is the NERC subregion that covers the Northeastern portion of North America including the Canadian Provinces of Ontario, Quebec, New Brunswick and Nova Scotia, as well as the areas served by NYISO and ISO-NE. In addition to national and regional reliability standards, the power systems in New York and New England are designed and operated to meet more stringent local standards established to address the area specific requirements of local power systems.

The NERTO region would have a peak load exceeding 50,000 MW, a transmission system comprising 18,775 miles of transmission lines, and several hundred generating plants with total installed capacity in excess of 61,000 MW. NERTO would serve a geographical area including seven states, encompassing an area of 110,024 square miles and a population of 32.9 million. The combined system would have a more diverse generating base and load-diversity advantages relative to today's individual markets, which could provide greater flexibility and efficiency in meeting reliability standards and criteria.

(A) Resource Adequacy

The New England and New York markets are structured so that the power systems have sufficient supply and demand resources to meet the NPCC's resource adequacy criteria:

> Each Area's resources will be planned in such a manner that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and regions, and capacity and/or load relief from available operating procedures, the probability of disconnecting non-interruptible customers due to resource deficiencies, on the average, will be no more than once in ten years.[24]

This criterion requires each area to have sufficient resources to meet its demand plus reserves while allowing for planned maintenance and forced outages and for assistance over interconnections with neighboring areas and regions. For example, if New York were viewed as a totally isolated system it could require installed reserves of approximately 25%,[25] or available resources equivalent to at least 125% of forecasted peak load, to meet the NPCC criteria. However, because of the availability of resources in neighboring regions through control-area assistance arrangements, New York's installed reserve requirement is 18%, an interconnection benefit of approximately 7% or more than 2,000 MW. The NPCC resource adequacy definition also factors in Emergency Operating Procedures, essentially an analytical method of anticipating capacity shortages.

[24] NPCC, Document A-2, Basic Criteria for Design and Operation of Interconnected Power Systems, 3.0 Resource Adequacy - Design Criteria (rev. Aug. 9, 1995).

[25] See New York Control Area Installed Capacity Requirement For The Period May 2002 - April 2003, New York State Reliability Council (December 14, 2001).

The New York and New England control areas currently meet the NPCC resource adequacy criteria and already realize the benefit of a reduction in their individual capacity requirements as a result of control-area assistance arrangements. Over time, a number of other factors should result in an overall reduction in the installed capacity needed to satisfy the NPCC resource adequacy criteria for the NERTO region, including:

- Further elimination of market barriers.
- Integrated system planning for the NERTO region.
- Additional diversity of generation resources in a combined region.
- Increased availability of demand response.
- Realization of the full control area assistance benefits through internalization into the combined systems.
- Economies of scale in the application of Emergency Operating Procedures.

Prior to NERTO formation additional analysis will be undertaken to quantify the potential benefits of using New England and New York resources to meet NERTO capacity requirements.

(B) Operating Reserve Requirements

The existing New York and New England control-area reserve requirements are based on operating reliability requirements specific to the Northeast region and each control area. At the regional level, the NPCC sets requirements that are observed by NYISO and ISO-NE. NPCC requirements are established to ensure that reserves will be available following certain contingency events.[26] The intra-control area requirements include the NERC reliability requirement that operating reserves be dispersed throughout the control area and that the

[26] NPCC Policy A-6.

selection of reserve resources consider the effective use of those reserves in an emergency, transmission limitations and local area requirements.[27] In New York, locational requirements are based on internal transmission limitations that result in the inability to activate reserves outside of transmission-constrained areas following either transmission or capacity-related contingencies.

Following implementation of a single dispatch, reductions may be possible in the overall cost of maintaining operating reserves for the NERTO region while maintaining or even improving reliability. Combined operation of multiple control areas could offer, in particular, potential reductions in reserves needed for a second contingency and total operating reserves relative to current requirements. Thus, the study examines the NERTO reserve requirements in the context of the existing New York and New England control area reserve requirements. The reserve requirements for NERTO will thus be less than the existing combined requirements of NYISO and ISO-NE while still maintaining the reliability of the region.

The study also estimates the potential cost savings based on the reduced NERTO reserve requirements. A minimum estimate of reserve savings can be derived from historical NYISO reserve cost data. The process of determining the historical NYISO reserve cost is detailed in Appendix C. This methodology generally assumes that the NYISO has the highest reserve costs. If this is not the case, the estimate understates the actual savings and is conservative; actual NERTO reserve cost savings could be larger.

Since New England is "electrically east" and PJM is "electrically west" of the New York Central-East interface, combined operation of the New York, New England and/or PJM markets could potentially value New England reserves at Eastern New York reserve prices and PJM

[27] NERC Operating Policy 1, Section A.1

reserves at Western New York reserve prices. Assuming revised reserve requirements for NERTO, the total regional savings amount to $22.8 million/year. Within NERTO, the distribution of reserve costs savings is $9 million for New York and $14 million for New England.[28] The revised operating reserve requirements and calculations of the cost savings associated with the formation of NERTO and a Three-Way RTO are shown in Appendix C.

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[28] Reserve savings for PJM were not specifically calculated. However, in a Three-Way RTO $10 million of the total savings are allocated to PJM. This is a conservative assumption given the location of the PJM reserves, which are on the western side of New York transmission constraints.

VI. Organizational Benefits and Costs

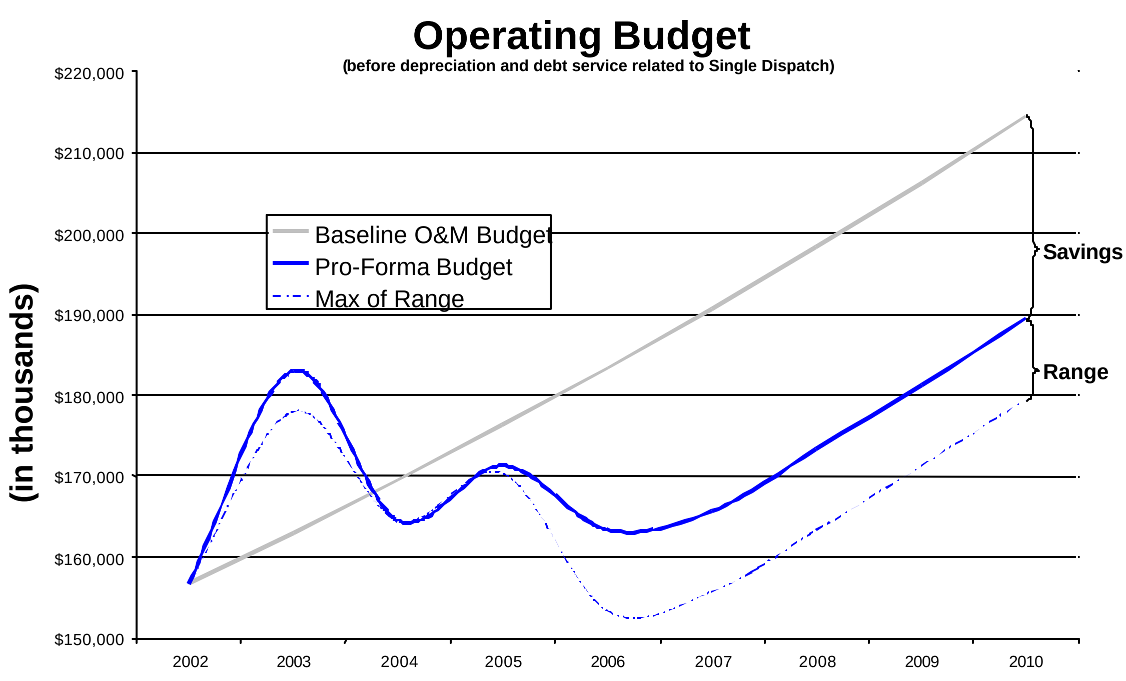
Synergy savings of the types normally seen in most business combinations will be realized from the formation of NERTO. The benefits and costs of combining the New York and New England markets and organizations, however, are not expected to follow, at least initially, the timing and pattern for conventional business combinations. Conventional combinations typically extract significant savings from operational synergies and attempt to realize this value early and quickly. The initial focus of the NERTO is capturing market efficiencies while continuing to operate similar, yet distinct, market systems in each of the existing regions. Operational savings in the initial years following formation of NERTO are projected to be modest. Synergies are expected to deliver small gains because the combined organization will focus on implementing more current versions of the Standard Market Design in the two existing regions, while beginning the design work necessary for a single dispatch across the regions. The savings that result from organizational optimization are expected to be realized in the operations and maintenance (O&M) and capital budgets.

(A) Operational Budget

Most of the O&M cost savings are expected to be realized once business processes and systems are integrated and rationalized; that is, once the development of the single dispatch is complete. These savings will come from workforce efficiencies gained by integrating business functions. The cost of integration in the earlier years following the combination will be offset in part by these savings. In the first year following the combination, savings will be realized by establishing one Board of Directors for the region and by centralizing executive management. Once NERTO leadership is centralized, many of the support functions, not related to market and system operations, may begin to consolidate their operations. Some business functions may be integrated fairly early. These functions will see some efficiency gain in the latter half of 2003 and 2004, with the greatest gains coming in 2005 and 2006. Later, O&M cost savings will be realized with the combination of an efficiently-sized workforce, synergies in the use of professional services, and efficiency gains in infrastructure services. The bulk of O&M cost savings will be realized by integrating the information technology delivery and operations activities once a single dispatch is implemented (See Figure 1).

The early gains in these functions may be offset by the costs of employee turnover, relocation and redeployment expected during the combination. In addition, it is unrealistic to believe that any material workforce efficiency could be realized when two markets are being operated and a single dispatch is under development. Significant operating efficiencies will not be realized until after the implementation of a single dispatch.

Figure 1 - Operating Budget Savings



In addition to functional efficiencies, savings are also anticipated from the ability of NERTO to obtain volume discounts on purchases and transactions in areas such as insurance, telecommunications, banking fees and building services.

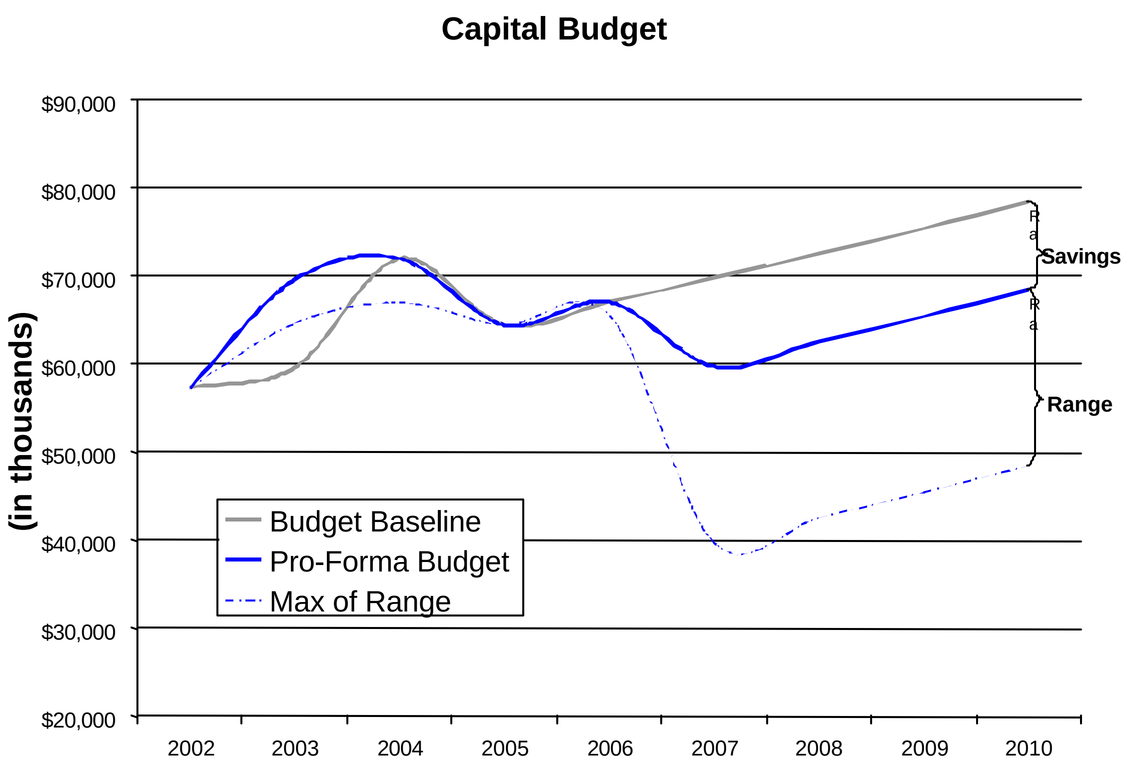
These latter-year operations and maintenance cost savings are expected to be $22-30 million annually, or beween 13% and 17% of the combined current year operating budgets of NYISO and ISO-NE.

(B) Capital Budget

The historical level of capital expenditures will continue in the early years while developing the single dispatch system. The capital costs are not additive to these historical levels of capital spending but rather a redeployment of those resources.

As shown in Figure 2, capital-budget savings are also expected in the latter years, after the implementation of a single dispatch. The study assumes that implementing a single, standardized market platform for the New York/New England region will reduce costs for future upgrades in applications and technology architecture. The substantial reduction in capital expenditures is estimated to be between $10 million and $30 million annually after single dispatch implementation.

Figure 2 - Capital Budget Savings



Efficiencies will come in two forms: cost-avoidance savings and synergy savings. Cost avoidance will occur as a result of using the existing control centers as redundant back-up sites for each other. Avoiding the construction of two new back-up control centers will result in cost savings of $10 to $15 million in 2004. Synergy savings will result from having a single focus on market designs and systems. Currently, enhancements to existing market systems amount to $50 to $60 million annually. It is expected that these future costs will be reduced after the single dispatch implementation.

(C) Estimated Costs and Benefits

Estimated organizational costs and benefits are shown in Table 29.

Table 29 - Organizational Costs and Benefits ($/millions)

Organizational Cost/Benefit

	2002	2003	2004	2005	2006	2007	2008	2009	2010	Total
Costs										
Operating Costs										
Startup and Organizational Integration Cost	5-10	20-30	5-10	5-10						35-60
Capital Costs										
Single Dispatch Costs**		5-10	40-70	30-50	10-30					85-160
Subtotal Costs	**5-10**	**25-40**	**45-80**	**35-60**	**10-30**					**120-220**
Benefits										
Operating Benefits										
Organizational Efficiencies (Initial Integration)		5-10	10-15	10-15	10-15	10-15	10-15	10-15	10-15	75-115
Organizational Efficiencies (Single Dispatch)					10-15	15-20	15-20	15-20	15-20	70-95
Capital Expenditure Benefits			40-65*	30-50*	10-30*	10-30	10-30	10-30	10-30	120-265
Subtotal Benefits		**5-10**	**50-80**	**40-65**	**30-60**	**35-65**	**35-65**	**35-65**	**35-65**	**265-475**
Net Benefits (Costs)	**(5-10)**	**(20-30)**	**0-5**	**5-5**	**20-30**	**35-65**	**35-65**	**35-65**	**35-65**	**145-255**

***Cost of single dispatch is not additive to historical levels of spending, therefore an offset has been applied in 2004 and 2005 to reflect the redeployment of capital expenditures to develop the single dispatch system.**

**** The capital costs of single dispatch are the costs of design, development, testing and implementation of a single dispatch and settlement mechanism. These costs are based on the high level plan developed by the NERTO task forces.**

Appendix A

Description of GE MAPS Model

MAPS

(Multi-Area Production Simulation)

Fundamental power system operating principles define the feasible alternatives for providing the required amount of electricity at any given point in time. MAPS (a proprietary software product from GE Power Systems Energy Consulting) simulates power system operations to predict the future price of electricity. The following describes the MAPS simulation model and its application in forecasting location specific power prices.

MAPS Power System Simulation Model

MAPS simulates power system operations based on a highly detailed system model. Individual generating units are modeled in terms of variable production cost contributors (fuel price, heat rate, and variable O&M) to determine the marginal (incremental) cost that unit would incur in supplying power to the grid. Sufficient generation is committed to satisfy load demand within the system control area and to satisfy operating reserve requirements. Operating flexibility characteristics (minimum and maximum power levels, minimum down time, etc.) are included to reflect limitations on individual unit operations. The transmission system is modeled in terms of the expected power flow that would occur as a result of the injection of power at each location and in terms of the limits that apply to the amount of power that can be transported on each line. A full security constrained dispatch is performed that recognizes transmission line flow under contingency conditions as well as normal operation.

Power demand is specified for each of the 8760 hours in a year and distributed between the various load buses in the system based on historical load patterns. MAPS uses a chronological, hourly simulation of system operations to capture the dynamic requirements imposed by hourly, daily, and seasonal changes in demand.

Optimizing System Operations

The MAPS operating model assumes individual generating units “bid” to supply power at their marginal cost of supplying power. MAPS uses a linear optimization process to determine the unit dispatch pattern that will minimize the total “cost” of supplying the power necessary to satisfy the load, subject to the constraints imposed by unit operating limits and transmission system limits. Based on the resulting dispatch pattern, MAPS determines the cost of providing an additional megawatt of power at each monitored location in the system, thus developing a location-based marginal price (LBMP) that fully reflects the transmission system congestion cost that exists during that hour. The resulting LBMP, combined with the predicted dispatch, determines the revenue a generating unit can expect to receive from a perfectly competitive wholesale energy market. Additional revenue streams to account for a unit’s failure to recover all variable operating costs from the energy market are included if these are provided for in the applicable market rules.

Appendix B

Hurdle Rate Calibration Methodology

Calibration of Hurdle Rates to Year 2000 Historical Transactions

Definition

Hurdle rates are used to represent all costs and other barriers to transactions between markets. In this study, hurdle rates are used to quantify the market impact of factors, such as:

1. Seams issues – inconsistent market rules and/or scheduling practices between regions that prevent transactions from occurring.

2. Export fees – transmission tariff charges and/or other fees incurred when importing or exporting power.

The hurdle rates employed in the study were determined pursuant to a calibration exercise based on actual data for 2000. The calibration exercise was used to produce results that are as close as possible to the actual transactions for 2000.

Calibration Methodology

The hurdle rates used in the simulation were determined using the MAPS model for a historic period (2000) and adjusting the hurdle rate until the simulated level of net interchange approximated the historical level of interchange. These hurdle rates were expressed as a dollar-per-megawatt-hour ($/MWh) barrier, and were adjusted between the Northeast ISO regions until predicted MAPS model flows were within approximately twenty percent (20%) of historically observed flows between the ISOs.

The calibration was performed on historical flows using a MAPS database with fuel costs and observed load data all using 2000 data. In addition, historical interchange in 2000 was adjusted to account for any known non-economic based transactions between regions, specifically the New York Power Authority ("NYPA") out-of-state deliveries. The net interchange for one-year historical flows was approximately 10,327 GWh from PJM to NYISO and 1,731 GWh from NYISO to ISO-NE, after adjusting for NYPA flows.

The hurdle rates that resulted in predicted MAPS model inter-ISO flows that most closely approximated the historical year 2000 inter-ISO flows are shown below:

NY->NE:	$10/MWh
NE->NY:	$11/MWh
NY->PJM:	$10/MWh
PJM->NY:	$7/MWh

These hurdle rates resulted in interchange within 95% of the PJM/NYISO 2000 net interchange and 79% of the NYISO/ISO-NE historic net interchange.

The following table presents the results of the various model runs used in the calibration process for several hurdle rate assumptions. The percentages shown below are the predicted MAPS model inter-ISO flows as a percentage of the 2000 net interchange less NYPA deliveries.

Calibration of Hurdle Rates		
Actual Inter-ISO Transactions	**Net PJM to NY**	**Net NE to NY**
• *2000 net interchange*	9,384,157.00	(2,384,172.00)
• ***2000 net interchange less NYPA deliveries***	**10,327,122.00**	**(1,731,041.00)**
Hurdle Rate Tested	**Net PJM to NY**	**Net NE to NY**
NY to NE:13, NY to PJM:12 NE to NY:14, PJM to NY:9	8,764,806	84,490
	85%	-5%
NY to NE:11, NY to PJM:12 NE to NY:12, PJM to NY:9	8,838,113	(354,885)
	86%	21%
NY to NE:10, NY to PJM:11 NE to NY:11, PJM to NY:8	9,437,555	(1,326,480)
	91%	77%
NY to NE:10, NY to PJM :10 **NE to NY:11, PJM to NY:7**	**9,815,627**	**(1,365,462)**
	95%	**79%**
NY to NE:9, NY to PJM 10 NE to NY:10, PJM to NY:7	9,974,680	(3,070,516)
	97%	177%

The values in bold were used in the study.

Refinement of the Hurdle Rate Calibration

This section provides further information about the hurdle rate calibration that was developed after the initial release of the draft study.

As indicated above, the objective of the calibration process was to determine year 2000 hurdle rates between regions such that the resulting GE MAPS model flows would closely approximate the actual year 2000 flows. The hurdle rate calibration resulted in predicted model flows that were within 79% of New York to New England actual flows and within 95% of New York to PJM actual flows.

The hurdle rate calibration employed in the study uses a grid search that considered only integer dollar values of hurdle rates. The restriction of hurdle rates to only integer values was a simplifying assumption necessitated by the short time available for completing the study. This restriction limited the potential for exact calibration of the year 2000 hurdle rates in the initial release of the study.

A subsequent analysis to validate the year 2000 hurdle rates was conducted using a finer grid search. This refined calibration process resulted in GE MAPS model flows that were within 1% of actual New York to New England and PJM to New York flows. The following tables present the effects of the various NERTO actions on wholesale power costs when they are evaluated using the refined hurdle rates.

Table B-1 - Revised Summary of Results

Northeast RTO Comprising New York/New England

	Annual Savings in Wholesale Power Costs			
	2005		2010	
NERTO Actions	**$ in Millions**	**% of Wholesale Power Costs**	**$ in Millions**	**% of Wholesale Power Costs**
Eliminate Seams/ Standardize Markets	33	0.4	6	0 0.1
Eliminate Export Fees	142	2.0	68	0.8
Single Dispatch	7[29]	0.1	33[30]	0.4
Sub-Total Market Benefits	**182**	**2.5**	**107**	**1.3**
Organizational Benefits[31]	10	0.1	36	0.4
Total Benefits	**192**	**2.6**	**143**	**1.7**

[29] Includes $23 million in reserve savings.

[30] Includes $23 million in reserve savings.

[31] The organizational benefits are assumed to be shared equally between New York and New England. This assumption is used throughout the study.

Table B-2 - Revised 2005 Summary of Results by Individual ISO

	Annual Savings in Wholesale Power Costs			
	New York		New England	
NERTO Actions	$ in Millions	% of Wholesale Power Costs	$ in Millions	% of Wholesale Power Costs
Seams Elimination/ Market Standardization	50	1.0	-17	-0.6
Eliminate Export Fees	166	3.6	-24	-0.8
Single Dispatch	34	0.7	-27	-1.0
Sub-Total Market Benefits	**250**	**5.3**	**-68**	**-2.4**
Organizational Benefits	5	0.1	5	0.2
Total Benefits	**255**	**5.4**	**-63**	**-2.2**

Table B-3 - Revised 2010 Summary of Results by Individual ISO

	Annual Savings in Wholesale Power Costs			
	New York		New England	
NERTO Actions	$ in Millions	% of Wholesale Power Costs	$ in Millions	% of Wholesale Power Costs
Seams Elimination/ Market Standardization	12	.0.3	-6	-0.1
Eliminate Export Fees	94	1.9	-26	-0.8
Single Dispatch	17[32]	0.4	16[33]	0.5
Sub Total Market Benefits	**123**	**2.6**	**- 16**	**-0.4**
Organizational Benefits	18	0.4	18	0.5
Total Benefits	**141**	**3.0**	**2**	**0.1**

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[32] Includes reserve benefits of $9 million.

[33] Includes reserve benefits of $14 million.

Appendix C

Operating Reserves Analysis

NERTO Operating Reserve Evaluation

There is a potential for reductions in the overall cost of maintaining operating reserves for the New York and New England regions following the single dispatch operation of NERTO. Combined operation of multiple control areas would, in particular, offer the potential for reductions in contingency reserves and total operating reserves relative to the current reserve requirements, In this evaluation, it is assumed that the combination of the individual ISOs into a larger RTO would permit realization of cost savings arising from reductions in operating reserve requirements. This evaluation attempts to quantify these potential savings given assumed reductions in locational operating reserve requirements for NERTO and the Three-Way RTO.

To evaluate the operating reserve benefits in this study, historical data from the NYISO was used because New York currently has the only operating market for operating reserves. The annual costs of supplying a month of operating reserves was calculated using historic operating reserve prices from New York. This amount was then multiplied by an estimate of the reduction in operating reserves possible under combined operation of NERTO or a Three-Way RTO.

It is possible to measure the incremental cost of operating reserves rather precisely for the NYISO, as the shadow price of each category of each type of reserves in the security-constrained unit commitment is currently extracted and saved.[34] The shadow price represents what it would cost to increase or decrease locational operating reserve requirements by one MW. These data have been extracted for the period September 2000 through February 2002.[35] Because the cost of reserves is seasonal, cost assessments can be skewed by the inclusion of individual months. The cost assessments discussed below have therefore all been prepared for 12 month periods within the period September 2000 through February 2002. The range in the cost assessments over various 12 month periods provides an indication in the variability in these potential cost savings.

The cost of reserves satisfying the overall NYISO control area reserve requirement reflects the historical cost of western New York operating reserves and is appropriate to assessing the potential reductions in operating reserve costs arising from combined RTO operation between NY and PJM. This is because reserves carried in western PJM would likely be able to satisfy the NYISO reserve requirement. The incremental cost of western spin over the various 12 month periods between September 2000 and February 2002 has ranged from $38,912/MWyear to $49,059/Mw year ($4.44/MWh to $5.60/MWh). The similar cost of Western 10 minute non spinning reserves has ranged from $10,470 to $14,765/Mwyear ($1.19/MWh to $1.69/MWh),

[34] The shadow price of reserves in the SCUC solution is not the same as the day-ahead component of the day-ahead clearing price of reserves, which does not include opportunity costs. The analysis in this appendix cannot be replicated from posted data.

[35] Locational pricing of NYISO reserves was implemented in October 2001. The data used in this analysis is the shadow price of these reserves in SCUC which was extracted and stored beginning in September 2000 for the original planned implementation date of locational reserve pricing. The actual implementation date was delayed by lack of timely FERC approval.

and the cost of Western 30 minute reserves has ranged from $10,467 to $14,164/MW year ($1.19/MWh - $1.62/MWh). [36]

Similarly, the cost of reserves satisfying the NYISO Eastern locational requirements (East of Central East) has ranged from $47,995 to $51,741/MW year ($5.48/MWh to $5.91/MWh) for spin, from $16,335 to $16,776/MW year ($1.86/MWh to $1.91/MWh) for 10 minute non spinning reserves, and from $10,489 to $14,169/MW year ($1.19/MWh to $1.62/MWh for 30 minute reserves on an annual basis. The higher value of the range for incremental reserve costs was used in the reserve cost savings analysis. Since ISO-NE is electrically East of Central east, combined operation of NYISO and ISO-NE would potentially permit reductions in the total reserves carried East of Central East by the NERTO.

These data measure the potential cost reductions from reducing the various operating reserve requirements if the most expensive reserves currently being carried are within the NYISO. Thus, if the reserves carried in ISO-NE were currently consistently lower cost than those carried in the NYISO, a reduction in the overall NERTO reserve target would enable the NERTO to reduce its purchases of reserves and, given the assumption, the most expensive reserves would be those located in New York. The figures developed above are therefore in the nature of a minimum cost saving as the cost savings would be higher if ISO-NE were currently scheduling reserves at a higher cost than that reflected in the NYISO data. In addition, to the extent that the incremental cost of reserves currently differs between NYISO East and ISO-NE or between NYISO West and PJM, there would be a potential for reducing total operating reserve costs prior to implementing reductions in the target level of operating reserves.

ISO-NE does not currently clear day-ahead reserve and energy markets and the day-ahead unit commitment process does not produce meaningful reserve shadow prices that could be used for historical cost assessment, so it is not possible to develop a fuller estimate of the potential NERTO operating reserve cost reductions reflecting more efficient reserve procurement between ISO-NE and NYISO East.

PJM does not currently operate explicit reserve markets, and does not publish information regarding the shadow price of capacity in its day-ahead reliability commitment. As a result, there does not appear to be a well defined reserve shadow price for PJM reserves that could be used to develop an improved estimate of the potential NERTO operating reserve cost reductions reflecting more efficient reserve procurement between ISO-NE and NYISO West.

[36] The shadow price of the various categories of operating reserves is calculated given the current operating reserve requirements and would be most accurate for small changes in operating reserve requirements. Reductions in the reserve requirements might somewhat also reduce the incremental cost of operating reserves, leading to gradually declining cost benefits associated with further reductions in operating reserve requirements.

NERTO Operating Reserves Analysis

Reserve Product	Max WNY (MWs)	Min ENY (MWs)	Min Total NY (MWs)	Min NE (MWs)	Min NY&NE (MWs)	Min ENY&NE (MWs)	East Reserve $/MW	NY Annual Reserve Savings	NE Annual Reserve Savings	NERTO Reserve Savings
10 Minute Sync										
Existing ISO	300	300	600	750	1350	1050				
Potential RTO	300	175	475	625	1100	800				
Reduced Req.	0	125		125	250	250	$5.91	$6,471,450	$6,471,450	
10 Minute Total										
Existing ISO	200	1000	1200	1500	2700	2500				
Potential RTO	200	750	950	1250	2200	2000				
Reduced Req.	0	250		250	500	500	$1.91	$2,091,450	$2,091,450	
30 Minute Total										
Existing ISO	800	1000	1800	2100	3900	3100				
Potential RTO	800	750	1550	1450	3000	2200				
Reduced Req.	0	250		650	900	900	$1.62	$0	$5,676,480	
							TOTAL	$8,562,900	$14,239,380	$22,802,280

Within NERTO, the distribution of reserve costs savings is $9 million for New York and $14 million for New England.

Three-Way RTO Operating Reserves Analysis

Reserve Product	Max WNY (MWs)	Min ENY (MWs)	Min Total NY (MWs)	Min NE (MWs)	Min NY&NE (MWs)	Min ENY&NE (MWs)	West Reserve $/MW	East Reserve $/MW	NY Annual Reserve Savings	NE Annual Reserve Savings	NERTO Reserve Savings
10 Minute Sync											
Existing ISO	300	300	600	750	1350	1050					
Potential RTO	300	175	475	625	1100	800					
Reduced Req.	0	125		125	250	250	$5.61	$5.91	$6,471,450	$6,471,450	
10 Minute Total											
Existing ISO	200	1000	1200	1500	2700	2500					
Potential RTO	200	750	950	1250	2200	2000					
Reduced Req.	0	250		250	500	500	$1.69	$1.91	$2,091,450	$2,091,450	
30 Minute Total											
Existing ISO	800	1000	1800	2100	3900	3100					
Potential RTO	400	750	1150	1450	2600	2200					
Reduced Req.	400	250		650	1300	900	$1.62	$1.62	$5,676,480	$5,676,480	
								TOTAL	$14,239,380	$14,239,380	$28,478,760

Within the Three-Way RTO, the distribution of reserve costs savings is $14 million for New York and $14 million for New England.

Appendix D

Capacity Assumptions for New England and New York

NEW ENGLAND CAPACITY ASSUMPTIONS

Existing Capacity

Existing capacity modeled in the cost benefit analysis will include all units listed in January 2002, Seasonal Claimed Capability Report (SCC) listed as Energy Management System Units (EMS). Units listed as Settlements Only (SO) will be disregarded.

Proposed Capacity

New unit additions are based on approved NEPOOL 18.4 applications and reflect only those that have started actual construction as of March 2002. Under these criteria, there are no units that are to be added to the NEPOOL system after 2005 and before 2010. Therefore, the total NEPOOL capacity is not expected to change.

Table 1: Assumed New England Capacity Additions

Unit Name	Assumed In-Service Date	Winter Capacity (MW)	Summer Capacity (MW)
Lake Road 1	Spring 02	279	236
Lake Road 2	Spring 02	279	236
Lake Road 3	Summer 02	279	236
ANP Bellingham 1	Summer 02	307	288
ConEd Newington	Summer 02	561	522
West Springfield 1	Summer 02	49	40
West Springfield 2	Summer 02	49	40
ANP Bellingham 2	Summer 02	307	288
AES Londonderry	Summer 02	768	678

Kendall Repowering	Summer 02	234	172
Milford Power 2	Summer 02	287	268
Sithe Mystic Block 8	Summer 02	850	707
Hope Energy	Summer 02	531	500
Milford Power 1	Summer 02	287	268
Fore River	Fall 02	843	700
Sithe Mystic Block 9	Fall 02	850	707
Meriden Power	Fall 03	574	536

Capacity Attrition

The capacity attrition assumptions that correspond to those assumptions reported within the "NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission 2001-2010", 2001 CELT Report, and is the same assumption as those assumed for the RTEP01 and RTEP02 projects. In those projects, there are no projected generating unit retirements.

NYISO Capacity and Transmission Projects

Accepted for Inclusion in the Annual Transmission Reliability Assessments

Class 2001 and Prior Projects Developer / Project	Size (MW)	Original In-Service Date	SRIS Approval	Status of Article X or Article VII Application
Pre-Class 2001 Projects				
PG&E Athens	1080	2003	Yes	Approved
PSEG Bethlehem (incr.)	350	2003	Yes	Approved
Class 2001 Projects				
LIPA/TE CT-LI DC Tie-line	330	2002	Yes	Approved
ANP Ramapo Energy	1100	2003	Yes	Accepted
KeySpan Ravenswood (1)	270	2003	Yes	Approved
NYPA Poletti Project	500	2004	Yes	Accepted
ConEd East River Repowering	288	2002	Yes	Approved
Mirant Bowline Point 3	750	2003	Yes	Accepted
Sithe Heritage Station	800	2003	Yes	Approved
SCS Astoria Energy	1000	2003	Yes	Approved
Class 2002 Projects Developer / Project	Size (MW)	Original In-Service Date	SRIS Approval	Regulatory Milestone Met (2)
NYC Energy Kent Ave	79.9	2002	Yes	Yes
Calpine Wawayanda	500	2003	Yes	Yes
ANP Brookhaven	580	2003	Yes	Yes
GenPower N.S.-NYC 49th St. DC Line	800	2004	Yes	Yes
LMA Lockport II	79.9	2002	Yes	Yes
Orion Repowering Phases 1 & 2 (incr.)	546	2004-5	Yes	Yes
AE Neptune PJM-NYC/LIPA DC Line 49th St.	600	2003	Yes	Yes
Fortistar VP –Staten Island	79.9	2002	Yes	Yes
Fortistar VAN –Staten Island	79.9	2002	Yes	Yes
PSEG Cross Hudson 49th St. Gen.	1018	2003-4	Yes	Yes
Calpine JFK Expansion	45	2002	Yes	Yes

Notes:

1. KeySpan is studying an alternate interconnection plan for the Ravenswood project (345kV vs. 138kV).
2. Regulatory Milestone:
   - Generation subject to Article X - Article X Application deemed complete or approved.
   - Generation not subject to Article X – application for environmental permit filed.
   - Transmission subject to Article VII – Article VII Application accepted or approved.

Source: NYISO Analysis and Planning Department
3/18/02

ATTACHMENT XI

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	)	
New York Independent System	)	**Docket No. RT02-___-000**
Operator, Inc.	)	

AFFIDAVIT OF DAVID B. PATTON, PH.D.

I. Qualifications and Summary

1. My name is David B. Patton. I am an economist and President of Potomac Economics. Our offices are located at 4029 Ridge Top Road, Fairfax, Virginia 22030. Potomac Economics is a firm specializing in expert economic analysis and monitoring of wholesale electricity markets.

2. I currently serve as the Independent Market Advisor for the New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE"). I have served in this capacity for the NYISO since May 1999 and for ISO-NE since June 2001. As the Independent Market Advisor, I am responsible for assessing the competitive performance of the markets, including assisting in the implementation of a monitoring plan to identify and remedy market design flaws and abuses of market power. This has included preparing a number of reports that assess the performance of these markets. These reports generally analyze the trading patterns in the Northeast, the extent to which barriers to trade compromise the efficiency of the markets, and the impact of certain market rules on the efficiency of the markets.

3. I have worked as an energy economist for thirteen years, focusing primarily on the electric utility and natural gas industries. I have provided strategic advice, analysis, and expert testimony in the areas of electric power industry restructuring, pricing, mergers, and market power. I have also advised other existing and prospective RTOs on transmission pricing, market design, and congestion management issues. With regard to competitive analysis, I have provided expert testimony and analysis regarding market power issues in a number of mergers and market-based pricing cases before the Federal Energy Regulatory Commission ("Commission"), state regulatory commissions, and the U.S. Department of Justice.

4. Prior to my experience as a consultant, I served as a Senior Economist in the Office of Economic Policy at the Commission, advising on a variety of policy issues including transmission pricing and open-access policies and electric utility mergers. As a member of the Commission's advisory staff, I worked on policies reflected in Order No. 888, particularly on issues related to power pool restructuring,

independent system operators, and functional unbundling. I also analyzed the competitive characteristics of alternative transmission pricing and electricity auctions proposed by ISOs.

5. Before joining the Commission, I worked as an economist for the U.S. Department of Energy. During this time, I helped to develop and analyze policies related to investment in oil and gas exploration, electric utility demand side management, residential and commercial energy efficiency, and the deployment of new energy technologies. This work included the development of policies in former President Bush's National Energy Strategy and the Energy Policy Act of 1992.

6. I have a Ph.D. in Economics and a M.A. in Economics from George Mason University, and a B.A. in Economics with a minor in Mathematics from New Mexico State University.

7. The purpose of this affidavit is two-fold. The first is to assess the validity of the assumptions and methods underlying the study of the costs and benefits of forming a Northeast RTO ("NERTO Study"). The NERTO Study was conducted by the NYISO and ISO-NE ("the ISOs") and included in the ISOs' Joint Petition for Declaratory Order Regarding the Creation of a Northeast Regional Transmission Organization ("NERTO") dated August 23, 2002 (the "Joint Petition"). The second purpose of this affidavit is to assess whether a combination of the New York and New England regions have attributes that are consistent with a "natural market".

8. Based on my review of the NERTO Study, I have concluded that the assumptions and methodology are reasonable and provide a sound basis for estimating the benefits that are likely to be achieved. However, the NERTO Study does not quantify all potential sources of benefits of the NERTO. For example, the formation of the NERTO and implementation of a single dispatch will reduce the frequency of capacity shortages in New York and New England by allowing power to freely flow in real-time to the areas of greatest demand. Because these conditions have historically occurred in both New York and New England, resulting in sharp

price increases in the spot market, the NERTO is likely to deliver net benefits to the two regions beyond those reported in the NERTO Study.

9. This is particularly important to recognize for New England where the NERTO Study shows that the total benefits for consumers in 2005 are negative. When the additional sources of benefits are realized, including the reduction in capacity shortages and the improved coordination of trade with Canada described in Section IV, I expect that New England will realize significant net benefits.

10. In discussing the appropriate configuration of RTOs, the Commission has introduced the concept of a "natural market" but has not provided clear guidance on how it intends to evaluate and define natural markets. The discussion of natural markets in the context of RTOs has generally focused on identifying those market areas where having a single RTO in operation rather than versus multiple RTOs would generate the largest net efficiency benefits (including potential diseconomies of expanding the operating area). These benefits fall into three categories – improving the efficiency of flows between the RTO areas, improving the management of internal transmission constraints within the an RTO area, and achieving unit-commitment efficiencies and operating-reserves savings.

11. Each of these categories is qualitatively assessed in Section IV with respect to the NERTO region. Based on this assessment and the benefits estimated in the NERTO Study, I am able to conclude that the NERTO region encompasses a natural market.

II. The Cost-Benefit Study: Assumptions and Methodology

12. I have reviewed the study titled "Northeast RTO Economic and Reliability Assessment" (the NERTO Study) submitted with the Joint Petition. I have also separately reviewed a document titled "Final Northeast RTO Cost Benefit Study Assumptions," which was prepared by the staff of the ISOs and presented to stakeholders in the course of the consultative process leading up to the present filing. I have also discussed the assumptions and methodologies applied in the NERTO Study with ISO-NE and NYISO personnel.

13. The NERTO Study evaluates the relative benefits of eliminating various barriers to trade between the ISO areas and of forming a Northeast RTO. The NERTO Study was performed using the GE Multi-Area Production Simulation Model ("GE MAPS"), which is a production-cost model that simulates the operation of the electricity system. Like the existing systems utilized by the ISOs in the Northeast, the GE MAPS model performs a daily commitment of regional generation and an hourly dispatch of regional resources to minimize the costs of serving load.

14. The load in the Northeast is dispersed across the region and relies on the transmission network for the deliveries of electricity required to serve it. The GE MAPS model includes a detailed representation of the regional transmission network that respects the limits on each transmission facility. In simulating market outcomes, the model assumes that each generator bids at variable cost. Using these bids, the model estimates locational prices equal to the marginal cost of serving load at each location on the network. This is comparable to the current energy pricing methodology used by the NYISO and PJM ISO and the methodology that will be adopted under ISO-NE's Standard Market Design.[1] Accurately reflecting the

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[1] Participants in these markets are not required to offer resources at prices equal to their variable production costs. However, most offers are close to this level in reality since offering a resource at its marginal cost will maximize a supplier's profit absent market power. Some resources have marginal costs that exceed their variable production costs. For these resources the GE MAPS offer-price assumption will be understated.

constraints on the transmission network is essential for producing reliable estimates of the benefits of forming a Northeast RTO.

15. GE MAPS also models the daily unit commitment process. This process involves determining which generators to commit for the following day to meet the system's energy and reserve requirements, given that each generator will incur fixed start-up costs. Models that do not address unit commitment generally assume that all generators are on-line, which would substantially distort the estimated energy price effects of forming an RTO and ignores entirely the unit-commitment savings.

16. Therefore, the GE MAPS model offers a reasonable methodological approach to evaluating the cost and benefits of NERTO formation.

A. Hurdle Rates

17. One of the key methodological choices in the MAPS Model is the use of hurdle rates to represent the current barriers to trade between the existing ISO systems. A hurdle rate is an economic barrier between two areas that prevents the model from dispatching additional power across the border between the two areas when the benefit of the transfer is less than the hurdle rate. For example, if the price difference between the areas is $11 per MWh and the hurdle rate is $9 per MWh, additional transfers will be scheduled, which will reduce the price difference. Once the price difference falls to $9 per MWh or less, no additional transactions will be scheduled.

18. A calibration process was employed in the NERTO Study to establish hurdle rates that reflect current conditions by running the model with 2000 data and attempting to match the net transactions between PJM and New York, and between New York and New England in 2000. The approach is reasonable at the aggregate level and is consistent with the approach taken by ICF Consulting in the RTO study sponsored by the Commission.[2] However, the calibration approach taken in the NERTO Study

[2] ICF Consulting, *Economic Assessment of RTO Policy*, prepared for the Federal Energy Regulatory Commission, February 2002, ("ICF Consulting Study").

was more accurate than the ICF Consulting Study because the latter attempted to match only the regional generation output levels in each area rather than the transaction levels between the areas, which is a much smaller target value (i.e., it results in a more accurate calibration).

19. The hurdle rates initially identified and used in the NERTO Study produced modeled net flows equal to 95 percent of the actual flows on the PJM-NY interface and 79 percent of the actual flows on the NY-NE interface. This initial calibration analysis was limited to integer hurdle-rate values, which limited its ability to yield modeled flows that approximated actual flows on the interfaces.

20. A subsequent calibration analysis employing a finer hurdle rate search identified hurdle rates that produced modeled flows within 1 percent of the actual net flows in each of the interfaces. These revised hurdle rates are slightly lower than the original hurdle rates used in the NERTO Study. This refined calibration resulted in a reduction in the projected savings for the "market standardization" case, but did not change the results for the elimination of export fees or the introduction of a single dispatch. The results of this additional analysis are reported in Appendix B of the NERTO Study.

21. Although the hurdle rate methodology is most appropriate for estimating the benefits of more efficient flows between ISO areas, it does have some important shortfalls. Hurdle rates are well suited to reflect the effects of market rules or other trade barriers that increase transaction costs for participants trading between the areas. However, some of the trade barriers are not economic and limit trading even when the difference in prices between two ISO areas is much larger than the hurdle rates. These are described in more detail in the Natural Markets section of this affidavit where I qualitatively describe the additional benefits that a NERTO would provide beyond those quantified in the NERTO Study.

22. Another limitation of the hurdle-rate methodology is that some of the barriers to trade could also change under different market conditions. For example, risks associated with trading between areas may increase under peak conditions when

prices are more volatile so that the hurdle rate may be higher in these hours and lower in off-peak hours. Note, however, that the portion of the hurdle rate attributable to the inter-ISO transmission charges would remain fixed since those tariff charges do not vary with market conditions.

23. Last, the fact that the calibration is based on 2000 data may cause the hurdle rates to be overstated since some improvements in market rules and scheduling have been made since 2000. The year 2000 was selected for the calibration in the Study because inter-regional transaction data would be consistent with readily available GE MAPS model data. If using the 2000 data caused the hurdle rates to be higher, the only effect on the NERTO Study results would be to attribute to "market-standardization" the benefits of some steps that the ISOs have already taken. Some portion of the market-standardization class of benefits reported in the NERTO Study is already being or will soon be realized.

B. Single-Dispatch Case Assumptions

24. To estimate the benefits of the single commitment and dispatch that would be possible under NERTO, the NERTO Study assumes that two improvements will occur when the NERTO is implemented. First, a residual $2 per MWh hurdle rate that is assumed to remain after market standardization is reduced to zero and inter-regional transmission fees are eliminated.[3] Second, the transmission capacity between the ISO areas is assumed to increase by 5 percent. In my opinion, both of these assumptions are reasonable.

25. These assumptions are conservative in comparison to the assumptions made in the ICF Consulting Study, which assumed:

- a 5 percent increase in all transmission capability (rather than just the capability at the interface between control areas);
- a 6 percent improvement in heat rates and 2.5 percent increase in availability for fossil-fired units by 2010; and

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[3] This assumption is consistent with the assumption made for the same purpose in the ICF Consulting Study.

- a 3.5 percent decrease in peak load associated with demand response by 2006.

26. Differences in assumptions between the ICF Consulting Study and NERTO Study are appropriate because the NERTO Study evaluates the benefits of combining two operating markets into a single RTO for the region while the ICF Consulting Study estimates the benefits of forming RTOs with operating spot markets in regions that currently rely on decentralized trading. To the extent that some of the improvements assumed in the ICF Consulting study are associated with the incentives provided by an efficient wholesale spot market, most of these incentives exist under the current markets operated by the NYISO and ISO New England.

27. With regard to the $2 hurdle rate, it is reasonable to assume that some residual barrier to trading would remain even after the inter-ISO transmission charges are eliminated and the barriers related to market rules and scheduling procedures are eliminated (prior to the implementation of a single market under NERTO). This $2 hurdle rate would reflect the uncertainty regarding which market will be more profitable and the residual costs of arranging transactions between the areas.

28. My only concern regarding the $2 per MWh hurdle rate assumption is that it may be too high (which would tend to overstate the benefits attributable to the formation of NERTO). Absent the transactions costs or other barriers that are assumed to be eliminated through the market standardization and elimination of transmission charges, market participants would likely respond to price differences of less than $2 per MWh. This is particularly true if the scheduling timeframes are reduced significantly to ease the scheduling uncertainties or procedures are modified to allow the ISOs more directly to dispatch the flows between the markets. However, because these transactions costs and uncertainties are not likely to be completely eliminated through market standardization and improvements in scheduling procedures, the $2 per MWh assumption is reasonable. In addition, the ICF Consulting Study sponsored by the FERC also assumed a $2 hurdle rate to reflect the seam between RTOs.

29. The other primary assumption employed in the Study for the single dispatch case is that the formation of the NERTO will increase the available transmission capability. Transactions are currently scheduled using a contract-path scheduling limit between the areas that assumes any generating units dispatched to transfer power between the areas result in the same flow on the interface connecting them. In reality, some generating units may cause more flow on the limiting transmission facilities than others so that optimizing the dispatch of the resources under a single RTO will make it possible to transmit more power between the areas.

30. The ISOs have utilized their engineering judgment to determine that five percent would be a reasonable approximation of this increase. Although I have not attempted to validate the engineering basis for the magnitude of the increase, the analysis shows that this increase in capability does not result in substantial changes in the regional benefits or flows. For example, the sensitivity case for increased transfer capability shows that the number of hours that the transmission constraint is binding is not reduced significantly when the capability of the interface is increased by 10 percent. Likewise, the benefits that forming the NERTO is expected to bring do not increase substantially with higher transfer capability.

C. Other Assumptions

31. I have reviewed each of the other assumptions that underlie the NERTO Study, including assumptions on fuel prices, capacity expansion, and load growth. I am of the opinion that these assumptions are reasonable, although sensitivity analyses are necessary in a number of areas to capture a wider array of potential future conditions and to determine how sensitive the results are to changes in these assumptions. The NERTO Study includes these sensitivity analyses, which I have reviewed and discuss below.

32. The assumptions that are likely to have the largest impact on regional flows in 2005 and 2010 are the fuel-price and capacity-expansion assumptions. Changes in fuel prices can significantly change the economic incentive to transfer power between regions. For example, rising natural gas and oil prices will increase the incentive to

export coal-fired and hydroelectric power from the Midwest, PJM, and Canada into the Northeast. Further, forecasts of fuel prices are subject to more uncertainty than forecasts of other variables underlying the analysis, such as load growth. For these reasons, the fuel price sensitivities are an important component of the analysis.

33. The capacity-expansion assumptions also play an important role. In the 2005 and 2010 timeframes, the assumed expansion in capacity will determine the relative quantities of excess capacity in each of the ISO areas and, thus, whether the region will be a net importer or exporter. For example, currently New York generally exports power to New England. By 2005, however, the capacity in New England is assumed to expand by close to 25 percent while the capacity in New York is assumed to expand by 17 percent. The NERTO Study results for that timeframe show that New England becomes a net exporter to New York due, in part, to the assumed capacity expansion.

34. The NERTO Study uses relatively conservative capacity-expansion assumptions, assuming far less capacity will be built than is currently in the generator-interconnection queue. This is reasonable because it is widely recognized that not all projects currently in the queue will be completed. Therefore, ISO-NE assumed that only projects currently under construction will be in service by 2005 and that no additional capacity will be added through 2010.

35. The NYISO was slightly less conservative in assuming that any project currently under construction and 50 percent of the projects with an approved System Reliability Impact Study ("SRIS") from the NYISO and an accepted Article X application with New York State will be in service by 2005, with the remaining 50 percent in service by 2010. This is conservative because all of the projects with an approved SRIS and accepted Article X have planned in-service dates prior to 2005, and this assumption does not consider the possibility of any additional projects. If more capacity came into service prior to 2005, the benefits in each of the cases

would be reduced as it would be less economic to import power to New York from PJM and New England.[4]

36. One concern regarding the assumptions used in the NERTO Study is that PJM's capacity expansion assumptions are much less conservative than the ISO-NE and NYISO assumptions (i.e., PJM's not requiring that projects be in an advanced stage of approval or under construction before including them in the study). For the base case, the ISOs agreed to accept PJM's assumption regarding capacity expansion, which includes almost 17 gigawatts of new capacity by 2005 -- nearly three times the quantities assumed in New York and New England.

37. If PJM realizes a smaller fraction of its projected capacity expansion than New York and New England realize, the NERTO Study will overstate the increase in power flows from PJM to New York as barriers to trade are reduced because less supply will exist in PJM. Since less supply would be entering New York from PJM, the net imports from New England to New York would increase as the marginal value of power in New York rises. Therefore, the PJM capacity-expansion assumption could both overstate the benefits of improved trading on the PJM-New York interface and understate the benefits of improving trading on the New York-New England interface.

38. At least one sensitivity case accounts for this concern by reducing the estimated new capacity for PJM. This case reduces the capacity built in PJM by 2005 from 16,558 MW to 9,571 MW, and in New York from 5,978 MW to 5,438 MW (so that in 2005 each entity has 50 percent of the total capacity additions projected by 2010). This case results in almost no change to the benefits in New York, but reduces the benefits slightly for New England, which would be exporting more power to New York.

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4 The 2010 results provide an indication of how the 2005 results would change if more capacity entered New York prior to 2005 since all of the planned capacity will enter by 2010 and no additional capacity is added to New England after 2005.

39. The last key assumption of the NERTO Study relates to the improvement in Canadian imports that may be facilitated by the formation of NERTO. The NERTO Study includes a sensitivity case that assumes a 25 percent increase in Canadian imports. This case does not include the full potential benefits of improved coordination of Canadian imports that would be possible under a NERTO. These benefits are discussed in more detail below in the Natural Markets section.

40. In summary, my review of the assumptions and methods utilized in the NERTO Study indicates that they are reasonable and appropriate for estimating the benefits of forming the NERTO, although some classes of benefits could not be captured by the Study. These additional benefits are described qualitatively in the Natural Markets section below.

III. The Cost-Benefit Study: Evaluation of Conclusions

41. The full results of the base-case analysis and the sensitivity cases are reported in detail in the NERTO Study. This section highlights some key results and findings that are important to consider in making policy choices regarding the NERTO proposal.

42. First, the NERTO Study shows that the vast majority of benefits available from improving the efficiency of the power flows between the ISO areas are attributable to eliminating barriers to trade, including eliminating multiple transmission fees and improving the standardization of market rules and scheduling procedures. This is not a surprising result since most of these barriers can be substantially eliminated through changes in the current ISOs' market rules and procedures.

43. However, the single-dispatch cases in the NERTO Study also quantify another main source of benefits that is exclusive to the formation of a NERTO – the improved utilization of the transmission capability between the ISOs' areas in transitioning from contract-path scheduling to determining flows under a single dispatch. This benefit is shown to be relatively modest for each of the increases in interface capability studied, including the 5 percent increase in capability in each of the

single-dispatch cases and the 10 percent increase in the "Increased Transfer Capability" case. The results of these cases indicate that the improved transfer capability that a NERTO could facilitate is not as significant to the market as eliminating the barriers to trade between the ISO areas.

44. Second, the production-costs savings confirm these results. Most of the savings reported in the NERTO Study correspond to consumer savings (i.e., reduced wholesale cost to load calculated as the change in the spot energy prices times the load). However, production-cost savings are a more direct measure of the economic efficiencies that are achieved in each of the scenarios because they encompass all changes in payments and revenues by loads and suppliers. Therefore, it is important to determine whether any of the conclusions of the NERTO Study based on consumer savings change when the analysis is based on the production costs.

45. In general, the production-cost savings are roughly half as large as the consumer savings, although the relative savings across the various cases are very similar under the alternative measures of savings. Therefore, the majority of the production-cost savings accrue from eliminating the transaction fees and standardizing market rules and procedures.

46. There is one important difference in the relative savings using the production-cost measure versus the consumer-savings measure. This difference relates to the incremental savings of forming the 3-way RTO compared to the NERTO. In consumer-savings terms, the total savings would be \$200 million for the 3-Way RTO versus \$130 million for the NERTO in 2005.

47. Alternatively, when measured by production-cost savings, the total savings would be \$85 million in the NERTO single-dispatch case versus \$91 million in the 3-Way RTO case in 2005. Given the magnitude of the total production costs in the PJM-NY-NE region, the savings under the two cases are indistinguishable. This is important since the production costs most accurately reflect the net economic efficiency of forming a Northeast RTO.

48. Third, the NERTO Study's sensitivity cases for high fuel price are important because any forecast of natural gas and oil prices is subject to substantial uncertainty in the timeframes analyzed. Therefore, it is important to understand how the results change with variations in assumed fuel prices.

49. The high fuel-price sensitivity cases result in higher prices throughout the region and change the distribution of benefits of eliminating trade barriers and implementing a single dispatch. The High Natural Gas and High Natural Gas/Oil cases increase the benefits for 2005 to New England by $85 million and $68 million while decreasing the benefits to New York by $73 million and $17 million, respectively.

50. In addition, the number of hours in which the limit on the transmission interface between New York and New England is binding decreases significantly, from 2,602 hours in the base case to 1,868 and 1,170 hours in the two cases with high fuel prices. This reduction is due to the change in the relative economics of generation in the ISO areas.

51. These results illustrate that fuel prices can substantially affect the economics of the power flows in the region. Nevertheless, eliminating barriers to trade will generate net benefits regardless of the future fuel-market conditions. Further, eliminating these trade barriers provides a form of economic hedge for the region against changes in fuel prices and other factors since the market area whose prices would be increased the most due to a change in these factors will increase its imports and mitigate the price effects.

IV. Natural Markets and RTO Configuration

52. In discussing the appropriate configuration of RTOs, the Commission has introduced the concept of a "natural market" but has not provided clear guidance on how to evaluate and define natural markets. This section identifies several factors that I believe are characteristic of natural markets and evaluates whether the proposed NERTO would have them.

53. "Natural" wholesale power markets are difficult to define because power flows, and by implication the suppliers that would be economical in some given area, will be substantially affected by fuel prices, generator outages, demand conditions, and other factors. In the context of RTOs, the discussion of natural markets has generally focused on identifying those market areas where having a single RTO in operation rather than multiple RTOs would generate the largest net efficiency benefits. These benefits fall into three categories – improving the efficiency of flows between the RTO areas, improving the management of internal transmission constraints within an RTO area, and achieving unit-commitment efficiencies and operating-reserves savings.[5] Each of these categories is qualitatively assessed below with respect to the NERTO region.

54. Any effort to define a natural market in the RTO context should focus on identifying those areas that maximize the benefits described above. It does not follow that the volume of current inter-area transactions indicates appropriate boundaries of a natural market. Relying on that measure ignores other factors that are more important in evaluating the comparative benefits of alternative RTO configurations.

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[5] Although benefits flow from expanding the scope of RTOs by encompassing increasingly broad areas, potential diseconomies can arise from operating markets over these larger areas. Such diseconomies can arise as transmission operators are compelled to use increasingly conservative operating assumptions and procedures that reduce the utilization of the transmission capability. The Commission recognized this potential diseconomy in Order 2000. Based on the size of the NERTO that would result from combining the NYISO and ISO-NE markets, I am of the opinion that these potential diseconomies are not likely to be significant.

A. Improving the Efficiency of Flows between Geographic Areas

55. One of the most significant attributes of a natural market is that operating a single market in a broader region (as opposed to relying on market participants to engage in transactions across the seam between the areas) results in improvements in the dispatch of energy and reserves between the regions.

56. RTO operation over a larger region may or may not facilitate increased electrical flows between the subregions it comprises. For example, when one area generally enjoys a cost advantage over an adjacent area due to differences in the costs of supplies, relatively large transactions may be scheduled from the low-cost area to the high-cost area to the full extent that the transmission system allows. The quantities of these transactions would not increase significantly from the formation of an RTO encompassing the two areas.

57. Alternatively, areas with supplies of similar costs can rely heavily on transactions to arbitrage the prices between them. In these cases, the transactions may be smaller and the direction of the net flows much less predictable. It is in such cases, despite the smaller transaction quantities, that the two areas are likely to constitute a "natural market" because a single RTO spanning the combined area can improve the effectiveness of this arbitrage and thereby generate benefits.

58. New York and New England have this natural market characteristic. Both areas rely on similar portfolios of generation and capacity margins, so that the transactions between them play a key role in arbitraging differences in prices between the areas. One way to evaluate the extent to which this occurs is to examine the price differences between the ISO areas when transmission capability is available.

59. Table 1 shows the percentage of the hours from January 1, 2001 to May 31, 2002 in which real-time prices in New York and New England differed by more than $10 per MWh and transmission constraints were not binding between the areas.

Table 1
Real-Time Price Differences Between
New York and New England
January 2001 to May 2002

Price Difference	New York Price Higher	New England Price Higher
\$10 - \$20	9.2%	11.5%
\$20 - \$30	3.2%	3.7%
\$30 and up	3.8%	2.4%
Total \$10 and up	16.2%	17.6%

Notes : To exclude the effects of transmission constraints, hours are excluded when the flow over the interface between New York and New England is within 100 MW of its limit. Percentage values reflect hours in category relative to all hours.

Source : NYISO and ISO-NE market databases.

60. This table shows that nearly 34 percent of the hours exhibit a price difference greater than \$10 per MWh, which exceeds the magnitude of the transaction charges to transmit power between the regions. These results also show that at the various levels of price differences, the differences favor each region roughly the same fraction of the time. This is evidence that these two markets rely on arbitrage to set efficient prices and reveals that the NERTO could bring significant benefits by improving this arbitrage.

61. The NERTO Study does not fully capture the benefits of improving the efficiency of the trade between New York and New England through the arbitrage of these price differences. First, the GE MAPS Model hurdle-rate methodology does not recognize the benefits of arbitraging price differentials larger than the estimated hurdle rate (e.g., \$8 to \$10 in the case of the New York – New England interface) even though a substantial portion of the hours exhibits price differences larger than this level. In other words, the base case against which the NERTO Study measures benefits (which includes the hurdle rates that represent current trading barriers), would not include any hours in which the price difference is greater than the estimated hurdle rate and the interface is not congested – the types of hours shown in Table 1.

62. Second, the NERTO Study's bidding assumption, that bids equal to generators' variable production costs estimate their marginal costs, limits its ability to reflect shortage conditions. Generators have generally bid competitively in the New York and New England markets with offer prices close to marginal costs. This is not surprising as this is the profit-maximizing offer for a generator lacking market power. However, a small share of the generating resources has marginal costs that exceed variable production cost levels due to operating risks and opportunity costs associated with production limitations.

63. When the system experiences capacity shortages – when the energy and reserve requirements cannot be satisfied under peak-load conditions – it will frequently dispatch resources with very high marginal costs and set energy prices that reflect the shortage condition. The GE MAPS model, which assumes bids at variable production cost, cannot set energy prices reflecting the capacity shortage.

64. During 2001, New York and New England each experienced capacity shortages while the other area was not in shortage and while transmission capability on the interface was available. Under these conditions, prices in the area with the capacity deficiency generally reflect the shortage. The following two tables identify instances when of these conditions existed.

65. Table 2 shows the hours in which (i) the real-time price in New York was more than $200 per MWh higher than the price in New England and (ii) New England was not experiencing a capacity shortage and yet thetransmission interface between the markets was not congested. (Hence, hours are excluded during which New England could not meet its own energy and reserve requirements are excluded even though the energy price in New England was well below the price in New York.)

Table 2
Unconstrained Hours with Large Price Differences into New York
January 2001 to May 2002

Date	Hour	New York Price	New England Price	Difference	Net Imports to NY
2 / 5 / 2001	17	$604.78	$61.86	$542.92	-1203
5 / 6 / 2001	13	$244.57	$40.95	$203.62	-663
5 / 12 / 2001	8	$544.06	$43.57	$500.49	-1039
5 / 12 / 2001	11	$830.21	$64.37	$765.84	-1091
5 / 12 / 2001	12	$1,035.87	$85.40	$950.47	-95
5 / 12 / 2001	13	$1,078.35	$82.57	$995.78	-349
5 / 12 / 2001	14	$1,068.39	$84.71	$983.68	-328
5 / 12 / 2001	15	$719.23	$69.47	$649.76	-463
5 / 12 / 2001	16	$292.34	$69.86	$222.48	-431
5 / 12 / 2001	17	$559.22	$59.30	$499.92	-486
5 / 12 / 2001	18	$421.95	$54.06	$367.89	-434
5 / 12 / 2001	19	$316.45	$45.36	$271.09	-392
6 / 16 / 2001	16	$455.97	$53.48	$402.49	-392
6 / 20 / 2001	15	$346.31	$108.37	$237.94	374
7 / 10 / 2001	12	$361.33	$65.00	$296.33	64
7 / 10 / 2001	13	$475.52	$65.00	$410.52	-286
8 / 8 / 2001	8	$763.10	$52.32	$710.78	-1216
8 / 8 / 2001	9	$602.53	$62.65	$539.88	-996
8 / 8 / 2001	10	$368.98	$78.94	$290.04	-954
8 / 8 / 2001	11	$285.30	$70.34	$214.96	-638
8 / 8 / 2001	13	$380.82	$65.00	$315.82	-800
8 / 8 / 2001	14	$683.05	$66.30	$616.75	-600
8 / 8 / 2001	16	$318.54	$73.76	$244.78	-305
8 / 8 / 2001	18	$337.08	$72.64	$264.44	-95
8 / 8 / 2001	19	$949.10	$77.50	$871.60	1
8 / 8 / 2001	20	$921.21	$88.01	$833.20	-131
8 / 9 / 2001	21	$389.30	$55.81	$333.49	-486
8 / 10 / 2001	10	$309.55	$99.52	$210.03	-454
9 / 9 / 2001	18	$246.55	$40.92	$205.63	-200
9 / 9 / 2001	19	$282.70	$62.36	$220.34	-11
9 / 9 / 2001	20	$475.41	$50.57	$424.84	66
12 / 26 / 2001	18	$281.24	$33.43	$247.81	-100
3 / 17 / 2002	18	$264.95	$40.31	$224.64	4

Note : Hours are excluded when the limit on the interface between New York and New England is binding or when New England is capacity constrained (i.e., cannot meet its own energy and reserve requirements).
Source : NYISO and ISO-NE market databases.

66. This table shows 33 hours during which the energy price was much higher in New York than in New England. The price shown for New York is the real-time Capital Zone price because this reflects the internal energy price in New York near the New

England interface. New York's proxy bus price for New England was not used because it could reflect interface constraints; the Capital Zone price better reflects the value of power within New York.

67. One caveat is that constraints could be binding within the New England system (not on the interface) that could limit exports to New York in some of these hours. Because New England is a net importer of power from New York in all but 5 of the 33 hours in the table, this factor probably does not explain why the net flow from New England to New York was not higher.

68. Table 3 shows the same data for those hours when the New England prices are more than $200 per MWh greater than the prices in New York in hours when the transmission interface between the two markets is not binding and New York is not capacity constrained.

Table 3
Unconstrained Hours with Large Price Differences into New England
January 2001 to May 2002

Date	Hour	New England Price	New York Price	Difference	Net Imports to NY
1 / 15 / 2001	16	$395.06	$52.10	-$342.96	-1298
2 / 16 / 2001	7	$427.48	$42.45	-$385.03	-629
3 / 10 / 2001	23	$288.41	$57.89	-$230.52	-1208
3 / 26 / 2001	7	$329.18	$56.96	-$272.22	-649
7 / 23 / 2001	18	$1,000.00	$52.70	-$947.30	-91
7 / 23 / 2001	19	$1,000.00	$48.46	-$951.54	-87
7 / 24 / 2001	13	$1,000.00	$70.42	-$929.58	-323
7 / 24 / 2001	14	$1,000.00	$67.92	-$932.08	-246
7 / 24 / 2001	15	$1,000.00	$81.39	-$918.61	-348
7 / 25 / 2001	12	$1,000.00	$267.72	-$732.28	-473
7 / 25 / 2001	13	$1,000.00	$199.87	-$800.13	-136
7 / 25 / 2001	14	$1,000.00	$692.94	-$307.06	-114
7 / 25 / 2001	17	$1,000.00	$57.90	-$942.10	-206

Note: Hours are excluded when the limit on the interface between New York and New England is binding or when New York is capacity constrained (i.e., cannot meet its own energy and reserve requirements).
Source: NYISO and ISO-NE market databases.

69. Table 3 shows that 13 hours meet this condition in New England, compared to the 33 hours in New York shown in Table 2. Although the prices shown in Tables 2 and 3 occur in only a limited number of hours in the real-time spot market where

only a fraction of the power is traded, these prices have broader implications since they affect prices in the forward energy markets. Therefore, improving the arbitrage in these hours can generate substantial benefits for both the forward and spot energy markets. This is a key element in determining whether the combined New England-New York region is a natural market.

70. Further, the net benefits that accrue in these hours are likely to be positive even when effects in the low-priced market are considered. The magnitude of the price effect in each market of facilitating additional trade is directly related to the slope of each region's supply curve. Under the conditions reflected in Tables 2 and 3 the high-priced market would generally be clearing at a very steep point on the supply curve, and the low-priced market would be clearing at a flatter point. Improving the transfers between the markets will generally cause the prices to fall in the capacity-constrained area by far more than the prices will rise in the adjacent area.

71. Therefore, the fuller utilization of the interface that would result from resolving the seams issues and employing a single dispatch would cause capacity shortages in New York and New England to occur less frequently, and result in significant cost savings for loads in the short run. The fact that a single dispatch would produce significant efficiency improvements associated with the flows of power between the two areas supports the conclusions that the combined region constitutes a natural market.

B. Commitment Efficiencies and Operating Reserves

72. The benefits of RTO formation extend well beyond facilitating transactions. In particular, improved regional commitment of resources and management of operating reserves are potential sources of substantial benefits from establishing an RTO. The fact that an RTO captures these benefits provides additional support for the conclusion that it encompasses a natural market. The NERTO would do this for the following reasons.

73. First, the NERTO's formation would allow for a reduction in the total operating reserves for the two ISO areas. An initial reduction in operating reserves of 200 MW was realized through a reserve-sharing agreement initiated in 2001 and plans are underway to expand this agreement to increase the quantity of reserve sharing. In practice, such reductions are limited by the ability of the ISOs to rely on protocols to activate the reserves in the adjacent region in response to system contingencies.

74. Further reductions in reserve requirements would be facilitated by the NERTO since it would procure operating reserves for the combined New York – New England region. These reductions together with the associated cost savings were estimated in the NERTO Study.[6] In addition to these quantity reductions, additional savings would result from the optimal designation of the operating reserves throughout the region.

75. The potential for improvement in the designation of operating reserves is due, in part, to the complementary nature of the generating portfolios in New York and New England. For example, New York generally has a surplus of peaking generation while such generation is relatively scarce in New England. Table 4 shows the types of generating capacity located in New York and New England.

Table 4
Comparison of New York and New England Plant Types in 2002

		New York		New England	
Plant Type	Technology/Fuel	MW	%	MW	%
Baseload	Nuclear	5,119	13.0%	4,340	16.2%
	Coal Steam	3,814	9.7%	2,414	9.0%
	Hydro and Other	6,735	17.1%	4,274	16.0%
Intermediate	Gas Steam	14,471	36.8%	6,954	26.0%
	Oil Steam	3,478	8.8%	6,941	25.9%
Peaking	Gas Turbine	5,723	14.5%	1,865	7.0%

6 *NERTO Study*, Appendix B.

76. Table 4 shows that New York has more than three times the quantity of peaking generation than New England. The balance of the regions' portfolios is comparable.[7] The similarities in the composition of the baseload and intermediate generation resources in New York and New England help explain why the markets have been difficult to fully arbitrage and why the direction of inter-regional flows has varied.

77. The NERTO would have the flexibility to optimize its selection of reserves, subject only to those locational requirements necessary to ensure the reliability of the system. This could result in having one of the ISO areas carry a much larger share of the region's operating reserves than is possible today. New York likely would hold additional reserves for the region since peaking resources are generally relied on to provide a significant share of the 10-minute operating reserves.

78. The benefits of the improved optimization of operating reserve designations would accrue not only in the reserve markets, but also in the energy market. Energy market benefits would result as resources are made available to the energy market that otherwise would have been designated to provide operating reserves under the existing ISOs' arrangements .

79. Hence, this is another area in which the characteristics of the markets in the Northeast suggest that the formation of the NERTO likely would result in significant benefits, providing additional support for the proposition that the NERTO area constitutes a natural market.

C. Improved Management of Canadian Imports

80. The last aspect of the NERTO formation that will generate savings and provides additional support for the conclusion that the NERTO area is a natural market relates to the management of imports from Canada. The interfaces from Canada into the Northeast are located in western New York (from Ontario) and northern

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[7] Although New York has a larger share of gas steam capacity, the age and other attributes of this capacity result in operating characteristics similar to oil steam capacity.

New York (from Hydro Quebec), and in northern New England (from Hydro Quebec and New Brunswick).

81. The NYISO and ISO New England have signed agreements with the market operators in Ontario and New Brunswick to work together to coordinate the development of the respective markets and facilitate trading throughout the NPCC. These agreements promise benefits to the entire region as the wholesale power markets develop throughout the NPCC.

82. The NERTO is likely to result in even greater benefits associated with improved coordination with Quebec due to the multiple interconnections between Hydro Quebec and the Northeast. Hydro Quebec is an active participant in both the NYISO and ISO New England electricity markets. Currently, to ensure system reliability each ISO individually limits the imports from Hydro Quebec below the physical capability of the interfaces. A substantial share of the imports into New York is actually wheeled to New England. The formation of the NERTO will allow the RTO to coordinate the imports across each of these interfaces to maximize the possible imports into the Northeast. The increase in import capability will have both economic and reliability benefits for the combined region.

83. The importance of the Canadian imports to the region was recognized by the New Hampshire Public Utilities Commission and the Vermont Public Service Board in their critique of the RTO study performed by ICF Consulting:

> "The fact is Canadian imports, *in toto,* are the single most significant power source defining reliability reserves for both New England and New York."[8]

84. This observation is correct as the Northeast allows Canadian imports to supply economic energy as well as to meet its installed capability requirements.

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8 Joint Comments of the Vermont Public Service Board the Vermont Department of Public Service and the New Hampshire Public Utilities Commission, Docket No. RM01-12-000, et al., at 29 (April 9, 2002)..

85. In sum, the improvements in the integration of the Northeast and Canadian electricity markets that would be possible with the formation of the NERTO are a source of benefits and provide an additional indication that the NERTO region encompasses a natural market.

V. Conclusion

86. The NERTO Study provides an appropriate analysis of the benefits that are likely to be achieved by the formation of a NERTO by the NYISO and ISO-NE. Although the assumptions and methodology employed in the NERTO Study are reasonable, the NERTO Study does not quantify all potential sources of benefits that would support the conclusion that the proposed NERTO region constitutes a natural market.

87. The natural-market policy criteria proposed by the Commission for establishing the scope and configuration of an RTO have not been clearly defined. I have suggested that these criteria be applied by identifying those geographic areas where having a single RTO operation rather than multiple RTOs would generate significant efficiency benefits while minimizing diseconomies of scale. The formation of the NERTO encompassing New York and New England would generate benefits in a number of ways as described above. Many of these benefits are estimated in the NERTO Study. Others that are difficult to estimate with the GE MAPS model have not been quantified but are significant nonetheless.

88. These additional benefits are described in the prior section and, together with the benefits quantified in the NERTO Study, support my conclusion that the NERTO region does indeed encompass a natural market.

89. This concludes my affidavit.

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ATTESTATION

I am the witness identified in the foregoing affidavit. I have read the affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

____
David B. Patton

August _____, 2002

Subscribed and sworn to before me
this _____ day of August, 2002

____
Notary Public

My commission expires: ___________________

ATTACHMENT XII

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	)	
	)	
New York Independent System Operator, Inc.	)	**Docket No. RT02-___ -000**
	)	

NOTICE OF FILING

Take notice that on August 23, 2002 ISO New England Inc. ("ISO-NE") and the New York Independent System Operator, Inc. ("NYISO") filed a Petition for a Declaratory Order seeking an order that the proposed Northeastern Regional Transmission Organization would qualify as a Regional Transmission Organization.

ISO-NE and the NYISO are serving a copy of the petition on the Governors and utility regulatory commissions of Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island and Vermont. A copy is also being posted on the websites of ISO-NE and the NYISO.

Any person desiring to intervene or to protest this filing should file with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). 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. All such motions or protests should be filed on or before the comment date, and, to the extent applicable, must be served on the applicant and on any other person designated on the official service list. This filing is available for review at the Commission or may be viewed on the Commission's web site at http://www.ferc.gov, using the "FERRIS" link. Enter the docket number excluding the last three digits in the docket number filed to access the document. For assistance, call (202) 502-8222 or TTY, (202) 208-1659. 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. The Commission strongly encourages electronic filings.

Comment Date:

Magalie R. Salas, Esq.
Secretary