APPENDIX A

STAKEHOLDER-IDENTIFIED SUB-ISSUES
ORGANIZED BY TOPIC

BUSINESS PLAN
FOR THE DEVELOPMENT AND IMPLEMENTATION
OF A SINGLE REGIONAL TRANSMISSION ORGANIZATION
FOR THE NORTHEASTERN UNITED STATES

September 10, 2001

APPENDIX A-1

Stakeholder-identified Sub-issues Pertaining to RTO Governance and Organizational Structure, ITCs, Market Monitoring and Mitigation, Costs, Financing and Recovery of Costs, and Information Release

I. Governance and Organizational Structure

A. Organizational Structure

- What will be the roles and responsibilities of the RTO and how will they be determined?
- If a single RTO is inevitable, what will make it work best in the long run for all its participants?
- If a single RTO is inevitable, what will best maintain reliability through the transition period?
- Who will lead?
- Should the NERTO be governed by an independent, non-stakeholder board that is advised by a broadly representative stakeholder structure (Stakeholder Committee or SC) and be managed by an independent staff under the board's direction?
- Should the Northeast RTO organizational and governance agreements, tariffs, and the like be structured to permit the incorporation of other control areas and market participants, consistent with the "open architecture" requirement of Order 2000?
- Should the NERTO governance structure and decision-making process encourage decisions that: solve issues in a fair and timely manner, use stakeholders' time and resources most efficiently, allocate costs equitably, and make the workings of the transmission system and wholesale markets transparent?
- Should the permanent staff operate independently under Board supervision? Transitional staff needs to draw from existing professional staff of all three ISOs, but not be necessarily co-equal with existing staff?
- What should be the basic organizational framework for the Northeast RTO, for-profit transmission company, not-for-profit regional system operator or a combination?
- What are the advantages and disadvantages of different organizational forms? (e.g.: Independent transmission company or transco as the RTO, possibly with ISO, IMO or other entity contracted to operate markets; Hybrid RTO consisting of ITC and ISO with defined division of authority (e.g., Jan. 2001 New England proposal as starting point); or RTO with provision for multiple ITCs with defined authority over transmission issues).
- What are the advantages and disadvantages for each structure, based on the structure's ability to deliver value to customers, including: accountability to transmission customers and market participants; potential benefits of separate transmission business unit and market business unit for the RTO; incentives for efficient and reliable operation of transmission system and markets; ability to manage and deliver interconnections; incentives for efficient investment in appropriate new transmission facilities; ability to attract financing to fund operations and investment in necessary new transmission facilities; incentives for innovation and deployment of new technologies; acceptability to asset owners and other stakeholders; and other factors?
- What are the division of responsibilities?

- Should the RTO be a for-profit corporation governed by an independent board elected by its members?
- Should the RTO be authorized to engage in lines of business which are not in conflict with its responsibilities as a transmission operator?
- Should RTO members consist of two classes: (1) Market Participants/Transmission/End Users and (2) Public Interest Members?
- Should market participants be signatories to RTO operating and reliability agreements, plus any other agreements required by their market participation?
- Should all market participants share in the liability of the RTO?
- Should the RTO be composed of at least two integrated but independent components, each with its own separate corporate structure and assigned functions?
- What are the RTO related agreements, including agreements necessary to establish the RTO, transfer control of designated transmission assets to the RTO and protect transmission owner rights, establish provisions for the termination of the RTO, and ensure that system reliability is maintained?
- What is the legal form of the RTO and what jurisdiction will it be organized in?
- What is the human resource plan?
- Should the RTO Board be a not-for-profit or for-profit organization?
- Should the Northeast RTO be founded as a non-profit or zero-profit organization?
- Should the Northeast RTO be permitted to own transmission facilities?
- Should the Northeast RTO have the authority to direct that facilities be constructed?
- Should there be a permanent legal entity created upon the creation of the RTO, subject to FERC approval?
- How will the RTO account for the issue that in some states public power cannot join for-profit organizations?
- How will the problems of combining for-profit and not-for-profit entities be resolved?
- What will be the organizational structure of the single Northeast RTO?
- How and when will responsibilities and functions performed by the existing three ISOs (PJM, New York and New England) be consolidated into the single Northeast RTO?
- Where will the single Northeast RTO's administrative staff be located? Will the Northeast RTO's offices be located in the same place as one of the existing ISO's control centers?
- Will the single Northeast RTO be a non-profit (ISO), a for-profit (transco/ITC), or a hybrid?
- What are the anticipated economic costs and benefits for consumers from each of the proposed RTO structure alternatives?
- Will the single Northeast RTO include an ISO?
- Should the Northeast RTO include an ITC? If so, should there be more than one ITC included as part of the single Northeast RTO? Under what circumstances would it make sense for there to be multiple ITCs within a single Northeast RTO?
- If there is one or more ITCs, how will responsibilities be divided among such ITC(s) and other parts of the RTO?
- Will all Transmission Owners be required to participate in one or more ITCs?
- Will the RTO (and/or the ITC) be stock corporations? If so, will their stock be publicly-held?
- If the RTO (and/or the ITC) is a stock corporation that is not publicly held, on what terms will participants be able to acquire ownership interests in the RTO?

- If the RTO is a non-stock corporation, on what terms may membership interests be acquired?
- Besides the RTO governing board, what committees (if any) will the RTO's decision-making employ? How will they be composed? What will their responsibilities and authority be?
- To what extent will the "Members Committee" structure employed in PJM, including the existing set of Members Committee voting (and other) rights and responsibilities, be included in the single Northeast RTO?
- If the Members Committee structure employed in PJM is used throughout the single Northeast RTO, will it be expanded to include a publicly-owned entities sector, as currently exists in NEPOOL?
- Will the single Northeast RTO be a FERC-regulated entity?
- In what NERC region will the single Northeast RTO be included?
- How should transitional RTO staff be established? How should permanent staff be established?
- What is the liability of the TOs?
- Should TOs be liable if they have no control?
- Should the RTO be liable if it has no means to absorb liability?
- Should the RTO be a for-profit corporation?
- Should the RTO be a not-for-profit organization that only operates and monitors the transmission system for owners who may be either for-profit or not-for-profit entities?

B. Board Composition, Rights, and Responsibilities

- Should the new Northeast RTO have a single Board, with its initial members taken from each ISO's Board in proportion to each ISO's load? Should this been done using "load-ratio" weighting?
- Should the total size of the new Board be consistent with the size of the current Boards (small, manageable number)? Should the maximum size be 10 members? Should the new Board initially have 6 from PJM, 3 from New York, and 2 from New England?
- As a transition measure, should there be a larger board to retain a broader range of talents from each region? Should the transition board include 8 from PJM, 4 from New York, and 3 from New England, for a total of 15?
- Should each existing Board nominate from among its current members to fill these new Board positions?
- Who should fill these vacancies?
- Should the governance structure set out under the Operating Agreement of PJM Interconnection, LLC, be applied to the Northeast RTO without change, other than to establish the new Board's initial composition and to provide for its enlargement during the transition period?
- Should there be a requirement for regional representation?
- Should the new board be seated promptly following approval of the consolidated governance structure by the FERC?
- What should the make-up of the RTO Board be and how should that be determined and maintained?

- Should the initial NERTO board be comprised of 3 or more members of each existing ISO board with the current ISO CEOs serving as ex-officio, non-voting board members?
- Should the board members who serve on the initial board reflect all of the areas of expertise and/or experience required of board members of the three Northeast ISOs?
- Should Board vacancies be filled either by the board (self-perpetuating per NY and NE) or by a 2/3s majority vote of the SC (per PJM) after an independent search firm recommends two nominees for each vacancy based on specific expertise needed on the board?
- Should, among the expertise required on subsequent NERTO boards, at least one member be required to have expertise on non-traditional electric resources such as customer-owned DG, load reduction resources, and/or renewable technologies; one member, expertise on environmental impacts of the electric industry; and one member, expertise on the impacts of electricity policies on small consumers?
- Should a self-perpetuating independent, non-stakeholder permanent board be created as soon as possible, no later than 24 months from the date of FERC authorization for the RTO?
- Should a transitional board be established?
- In two years, should a stable, permanent board of 12-15 board members remain (similar to New York ISO)?
- Should no more than nine members come from the existing ISO Boards of the merging institutions?
- Should the permanent board be developed through a search firm with two candidates for every position?
- In the interim, should a transitional board be established and should it be comprised of representatives of the three existing ISO boards (no more than three from each Board) and new board members with unique expertise (no more than three), e.g. in integrating large scale software systems?
- If established, should the transitional board phase out within six months of the establishment of the permanent board?
- What are the role and responsibilities of the RTO board of directors, including its responsibilities with respect to: development of RTO policies and procedures; development of the RTO budget; revisions to RTO tariffs and related agreements; market monitoring and mitigation; transmission expansion; adherence to reliability standards and maintenance of system reliability?
- Should the RTO be governed by an independent Board holding section 205 powers, but with an obligation to exercise those powers fairly and in consideration of all positions and obligated to provide in detail reasons for rejecting any advisory proposal?
- Should the board be installed immediately after FERC issues its final mediation order?
- Should the board consist of members selected from the existing three ISO boards in proportion to the load each system presently carries?
- Should the new board consists of a total of eleven individuals: 10 board members plus the CEO? (5 existing board members from PJM, 3 from NYISO, 2 from NEISO, CEO, selected by the board)
- Should the RTO board be selected by each ISO board selecting among the existing board members?
- Should the RTO board select the new CEO?

- Should the board be responsible for shepherding the new RTO market design and implementation?
- Should the transitional board continue in being for the duration of the transition process or 4 years whichever is shorter?
- Should, after the transition process, one fifth of the board stand for election each year by the RTO members?
- Should the CEO serve at the pleasure of the Board?
- Should elections for new board members be done annually?
- Should the election for new board members require both a simple and load weighted majority of all members?
- Should qualified candidates not be affiliated, employed or retained by any market participant prior to, during or for at least two years after serving as board members?
- Should the board have all Federal Power Act section 205 filing powers (except for those shared with the market monitoring unit with respect to market power and market abuse filings)?
- What is the governance structure to ensure independence of RTO in light of organizational framework selected? (Independent Board for ITC/Transco, if selected; Passive Ownership Rights in ITC/Transco, if selected; Independent Governance for Non-Profit RTO, if selected).
- Should the primary responsibilities for the Northeast RTO Board be consistent with those assigned to the PJM Board under 7.7(i) of the PJM Operating Agreement, namely, (a) the safe and reliable operation of the Interconnection, (b) the creation and operation of a robust, competitive, and non-discriminatory electric power market, and (c) that members or groups of members shall not have undue influence over Interconnection operations?
- Should there be one independent governing body for the entire Northeast RTO with Board membership qualifications consistent with the PJM Operating Agreement Section 7.2, viz., closing membership to any person having an employment or business relationship with a member of the Interconnection within at least the past 5 years?
- Should the meetings of the RTO Board be open except where closed meetings are necessary to address administrative matters such as hiring, disciplining and firing of employees or sensitive matters related to market power abuse or other investigations involving confidential information?
- Should the independent Board have exclusive authority for making decisions for the RTO, i.e., should the Board retain all Sec. 205 filing rights subject to meaningful stakeholder input and potential protests by stakeholders under Sec. 206?
- Should the Board seek the input of stakeholders on all matters and proposed FERC filings?
- Should the rules governing Board decisions include frequent and unrestricted opportunities for the inclusion of advice, information and proposals from stakeholder committees?
- Should the Board be required to act on all stakeholder-approved proposals within a reasonable amount of time?
- Should the Board be required to seek extensive stakeholder input regarding all planned FERC filings within a reasonable time frame prior to such filings except in emergencies?
- Should the Board be required to fully explain its decisions in writing, by posting on its web site, including its reasons for proceeding with emergency filings?

- Should the Board be required to maintain a written record of its meetings, to be posted on its web site?
- Should the Board be required to fully justify, via posting on its web site, its decisions, particularly regarding cases in which the Board has acted in a manner inconsistent with stakeholder consensus?
- Should the Board fully inform stakeholders, via posting on its web site, regarding planned actions prior to its approval of those initiatives? If so,
  - Should such notice be given sufficiently in advance as to allow the appropriate stakeholder committees to address the matter at their next routinely scheduled business meetings?
  - Should notice topics include plans, research, and proposals which are under consideration, including planned FERC filings?
  - Should notice also include financial information, risks and budgets?
  - Should information from the Board include operational performance of the Interconnection and problems?
- Should the Board post on the RTO web sites its contacts with all members, stakeholders and other parties? If so,
  - Should this requirement be restricted to only formal contacts?
  - To which types of unofficial contacts with stakeholders and outside parties should this requirement extend?
  - Should contacts be documented to include a brief description of the substance of what was communicated?
  - Which Board communications should be protected by confidentiality, for example, administrative matters such as hiring, disciplining and firing of employees or sensitive matters related to market power abuse or other investigations involving confidential information?
- Should the Board be responsible for providing an Annual Report, to be posted on its web site and, for critical issues, more frequent reports as requested by an appropriate majority of stakeholders?
- What is the size of the board, its composition and the qualifications of its members?
- What should be the process for the selection of the initial board members?
- Should the RTO governance structure use an approach under which one-third of the members of the RTO governing board would be selected from a pool nominated by state governments, similar to the public representatives on some Corporate Boards of Trustees? These public interest representatives could be explicitly chosen to represent the public interest, but would not be subject to short-term political maneuvering. To ensure their independence, the public interest representatives could have long and tenured terms (6-10 years) and they could only be removed 'for cause.' This would insure their independence, insulate them from short-term political influence, and result in important institutional longevity, since only one or two of these positions would change each year.
- Will there be a single governing board for the single Northeast RTO?
- Will the existing ISO boards be disbanded? If so, when? What will be the relationship between the single Northeast RTO board and the boards of the existing ISOs? How will conflicting decisions be resolved?
- How many board members will the single Northeast RTO's board have?
- Will there be regional restrictions on Board membership?
- What type of board will it be (stakeholder, non-stakeholder, hybrid)?
- How will the initial directors be selected?

- What should be the term of each RTO Board member?
- How will vacancies be filled?
- Can directors be removed before the end of their terms? Under what circumstances? By whom?
- Will there be any limits on the scope of the board's authority? Will any board decisions be subject to veto by RTO shareholders (if any)? Will there be any matters regarding which the board is not permitted to vote?
- What authority will the single Northeast RTO Board have concerning any potential ITC or ITCs created as part of the single Northeast RTO?
- What voting rules will apply (e.g., allocation of votes, need for a quorum)?
- What fiduciary duties will RTO management have and to whom?
- Will the fiduciary obligations of RTO management be set forth in a written and enforceable agreement?
- Will board meetings be open or closed?
- If board meetings are to be closed, what procedures will be in place to ensure that adequate information is disseminated to stakeholders?
- What obligations will the board have to respond formally to stakeholder concerns?
- How do we assure that the RTO board is structured and composed in a manner that will be sufficiently responsive to the environmental and renewable aspects of national energy policy, such as those articulated in Chapter Three of the National Energy Plan (i.e., Report of the National Energy Policy Development Group, "Reliable, Affordable and Environmentally Sound Energy for America's Future")?
- How should RTO Board membership be determined?
- Should the RTO board include a majority of new members that are not members of the three existing ISO boards?
- Should elections for new board members be done annually?
- Should the board members be added/replaced by market participants?
- Should the election for new board members require both a simple and load weighted majority of all members?
- Should qualified candidates not be affiliated, employed or retained by any market participant prior to, during or for at least two years after serving as board members?
- Should a new CEO be selected (from outside of the current ISOs) to organize the combined ISO staffs?
- Should the RTO board select the new CEO?
- Should the CEO serve at the pleasure of the Board?
- Should there be a process by which market participants review the performance of the CEO?
- Should the Board select a new law firm to represent the RTO?
- What are the Section 205/206 filing rights of an ITC, if there is one?
- Should the NYISO model be adopted with respect to Section 205/206 filing rights be adopted as a viable option?
- Should the board be required to comply with all Sections of the Federal Power Act, including Sections 210-212?
- Does the board have the right to change any of the enabling agreements other than through Section 206 of the Federal Power Act?
- Should the organizational RTO documents recognize the environmental implications of NRETO operation and policies (including market developments) and articulate the Board's responsibility to consider the environmental consequences of NERTO

policies and operations and to balance, as reasonably as possible, the risks of harm to the environment against the benefits derived from such policies and operations?

- Will the RTO Board be the only decision-making body in the RTO, or will it delegate specific decision-making authority to other committees?

C. Stakeholder Role

- How to provide for stakeholder input while permitting the RTO to make a Section 205 filing without stakeholder committee approval?
- How to ensure sufficient state public commission input into RTO decisions?
- How can the stakeholder committees be structured to provide a fair representation of the parties and be made effective in advising the RTO Board?
- How can funding be provided to stakeholders who do not have the resources to adequately participate?
- Should the NERTO Stakeholders Committee (SC) be comprised of six sectors – e.g., (1) Transmission Owners; (2) Generators; (3) End-use Customers; (4) Wholesale Marketers and Other Suppliers; (5) Load-serving Entities; and (6) Public Sector entities, which should include Northeast State Utility Regulatory Commissions, State Consumer Advocate Offices, and bona fide NGO environmental and consumer public interest groups?
- Should all sector definitions be broad enough to enable participation by (or avoid participation barriers for) smaller members of stakeholder groups?
- Should proposed market rule changes and other recommendations to the NERTO board be adopted by a two-thirds, sector-weighted majority using the existing PJM rules for voting, with the clarification that abstentions not be counted as affirmative or negative votes?
- Should the Northeast RTO be required to respond to SC recommendations within five business days either by making a FERC filing seeking approval of changes recommended by the Stakeholders Committee or providing a written explanation of why the RTO declines to make the filing, including any modifications deemed by the RTO to be necessary for it to make a NERTO filing at FERC on the matter?
- If the RTO declines to file for FERC approval of an SC recommendation within the 5-day period, should the SC have the right to require RTO staff to make the filing under Section 205 on behalf the RTO SC?
- Should the SC be authorized to designate, as it deems appropriate, SC sub-committees, which are subordinate to the SC?
- Should the Northeast RTO staff chair each sub-committee and perform all administrative functions, including timely internet posting of agendas and minutes, associated with sub-committee activities?
- Should all sub-committee meetings be open to all interested stakeholders?
- Regardless of whether the NERTO governance structure provides a voting or non-voting role for stakeholders on market and transmission issues, should it provide a meaningful opportunity for stakeholder input, for airing and resolving stakeholder concerns, have low barriers to entry to facilitate broad representation, and afford meaningful participation for stakeholders that have traditionally not had a voice in decision-making on wholesale electrical issues (e.g. small consumer, renewable, and environmental interests)?
- Should a permanent Advisory Stakeholder Group be comprised of six sectors: (1) Transmission Owners; (2) Generators; (3) End-Use Customers; (4) Wholesale

Marketers and Other Suppliers, including energy service companies, (5) Load Serving Entities and (6) bona fide public interest groups?

- Should a Transitional Advisory Stakeholder Group be similarly constituted?
- Should the role of the transitional stakeholder group be to negotiate the implementation of the RTO, and to serve in an advisory capacity until replaced by a permanent stakeholder group?
- Should voting by the stakeholder group be three-fifths majority vote (approximately the New York model)?
- Should governmental entities be advisory only, except for public power entities?
- What are the role and responsibilities of RTO stakeholder committees, including: eligibility to participate in RTO stakeholder committees; the structure and voting rules of the committees; relationship between committees and the RTO board and staff; the number of committees and their responsibilities with respect to: development of RTO policies and procedures; development of the RTO budget; revisions to RTO tariffs and related agreements; transmission expansion; and selection of RTO board members?
- Should stakeholder committees be advisory to the board and not have FPA section 205 rights?
- Should advisory committees have the right to select their own leadership and conduct meetings according to a uniform procedure common to all RTO advisory committees?
- Should committees follow an open and collaborative discussion and dispute resolution process?
- What are the provisions for meaningful stakeholder participation?
- Should all stakeholder committee meetings be open with sufficient advance notice posted on the website?
- Should all minutes of all stakeholder meetings be posted timely on the RTO website?
- Should there be a single stakeholder process for the entire Northeast RTO?
- Should membership criteria for stakeholder sectors be uniform throughout the Northeast RTO and be designed to prevent improper influence and prohibit votes in multiple sectors by affiliates?
- Should regional differences which must continue be managed through regional stakeholder subgroups within the overall Northeast RTO stakeholder process?
- Should stakeholder voting be on a weighted sector basis provided that each sector is free to communicate its position in writing to the Board by means of a motion adopted by a majority of the sector?
- Should stakeholder voting ensure equal weighting among sectors and ensure that no single stakeholder has unbalanced weighting in the voting protocol within any sector?
- Should the advisory function of stakeholder committees be genuine and meaningful?
- Should stakeholder committees be responsible for initiating proposals, including proposed tariff filings and changes in market structure, design and rules, for Board consideration?
- Should governmental entities be granted voting rights which are equal with other stakeholders with no financial liability, other than a reasonable annual fee consistent with their status as governmental entities?
- Should state and federal regulatory agencies have the right to participate fully in non-voting status in the activities of any committee?
- What is the relationship between the RTO and transmission owners including: TO § 205 rights to ensure full recovery of revenue requirements; TO ability to satisfy

obligation to provide safe and reliable service, including the ability to make system enhancements needed to ensure reliability; TO ability to take appropriate action during emergency situations to maintain safety and reliability, and to protect people and assets?

- Should entities with affiliates choose only one sector and have only one vote?
- Should all committees follow an open and collaborative discussion and dispute resolution process?
- Should there be standing committees, such as Members Committee, Finance, Reliability, Tariff, Operations, and Public Interest and Environmental?
- Should any committee or subcommittee have the right to form a working group by request of 5 or more members?
- Should voting protocol be uniform?
- Should there be a simple majority for voting on matters not involving modifications or additions to an RTO tariff?
- Should voting be based on a simple majority and sector majority bases for tariff related issues?
- Should sector membership be self selecting?
- How can the stakeholder process provide meaningful representation of residential and small business interests that traditionally are under-represented?
- Should the RTO provide funding for the adequate representation of these customers?
- Should consumer advocates be given the opportunity to represent small consumers, as in New York?
- Should the RTO Board certify "Regional Consumer Advocates" that represent small consumer interests in the different regions? The NYISO certified a "State-Wide Consumer Advocate."
- Should consumer advocates be active members of the RTO with full voting rights in the different committees, as in New York?
- If consumer advocates are not given voting membership, who will represent the interest of the millions of residential and small business customers?
- How will small consumer interests be fairly represented in the Transitional Stakeholder Process established to negotiate the formation and implementation of the RTO?
- Who are the stakeholders with respect to the single Northeast RTO?
- What role will the stakeholders play in the affairs of the single Northeast RTO?
- What mechanisms will be in place to enable the stakeholders to hold the single Northeast RTO accountable for meeting its obligations?
- What rights will RTO stakeholders have to make filings with the Commission to amend RTO arrangements?
- Will the stakeholders of the single Northeast RTO conduct business pursuant to a sector voting arrangement?
- If a sector voting arrangement is adopted, will there be a separate sector for Public Power as there is in NEPOOL?
- If there is a Public Power sector, will membership be limited to publicly-owned or cooperatively-owned entities that own facilities for the generation, transmission, or distribution of electricity?
- If a sector voting arrangement is adopted, will it be a one-entity, one-vote structure or will there be weighted voting?
- If voting is on a one-entity, one-vote basis, will an entity be able to split its single vote among its separate affiliates?

- How will the voting structure accommodate proxy voting?
- Will sector membership be determined on a self-selection basis or will sector selection be made by a separate entity?
- Will there be a single stakeholder advisory committee, or will there be multiple subject matter committees in which stakeholders may participate?
- How will any such stakeholder committee(s) be composed? How will the stakeholders be organized?
- When will the stakeholder committee(s) be formed?
- How will stakeholder committee(s) interact with the board?
- How will stakeholders be kept apprised of matters the board intends to consider at regularly-scheduled and special board meetings?
- Will stakeholders have an opportunity to review and comment on the RTO's proposed budget?
- Will stakeholders have an opportunity to review and comment in advance on drafts of filings the RTO intends to make with the Commission?
- How will the stakeholder advisory process be structured to ensure that both majority and minority stakeholder positions come to the attention of the board?
- What responsibility will the board have (if any) to respond formally to rejected stakeholder positions?
- How will the stakeholders present their position(s) on issues to the single Northeast RTO?
- What mechanism will exist to challenge actions of the managing entity of the single Northeast RTO?
- Who will have the right to challenge actions of the managing entity of the single Northeast RTO?
- With regard to market monitoring and mitigation plans, how will stakeholders' rights to make Section 206 filings without first pursuing remedies through the RTO stakeholder process be explicitly reserved under the Northeast RTO?
- How can the stakeholder process provide meaningful representation of residential and small business interests that traditionally are under-represented?
- Should the RTO provide funding for the adequate representation of these customers?
- Should consumer advocates be given the opportunity to represent small consumers, as in New York?
- Should the RTO Board certify "Regional Consumer Advocates" that represent small consumer interests in the different regions? The NYISO certified a "State-Wide Consumer Advocate."
- Should consumer advocates be active members of the RTO with full voting rights in the different committees, as in New York?
- If consumer advocates are not given voting membership, who will represent the interest of the millions of residential and small business customers?
- How will small consumer interests be fairly represented in the Transitional Stakeholder Process established to negotiate the formation and implementation of the RTO?
- How do we assure that any stakeholder structure or process will be sufficiently responsive to the environmental and renewable aspects of national energy policy, including those aspects articulated in the National Energy Plan?
- How will the RTO Board be held accountable to the market participants and asset owners?
- Does sector voting result in proposals that are in the public interest?

- Does sector voting allow fair participation by all interested stakeholders?
- Should non-member stakeholders be provided opportunity for input and comment on proposals for Board consideration? Should there be a mechanism for non-participant stakeholders to submit proposals of their own? How could such a process be designed so it would not be overly burdensome for the RTO?
- Should proposals for Board consideration be noticed and presented in standard format (e.g. problem or opportunity to be addressed, advantages, disadvantages, major alternatives)?
- How can the advisory process be designed to facilitate input from stakeholders with geographic and/or economic constraints?
- Should the state regulatory commissions have representatives on the Public Sector of the RTO Stakeholders Committee (including those states that PJM-West extends into: Ohio, Virginia and West Virginia)?

D. RTO Expansion

- Should each component be designed to be capable of growing beyond the current boundaries of the "Northeast"?
- How will the Northeast RTO governance documents accommodate new control areas?
- How will the Northeast RTO governance documents accommodate changes to governance?
- Will the single Northeast RTO be either encouraged or prohibited to expand geographically?
- What provisions will be included to facilitate expansion of the single Northeast RTO into Canada or its affiliation with counterpart Canadian entities?
- Will there be any limits on the ability of the single Northeast RTO to diversify into other lines of business (e.g., telecommunications)?
- What should be the provisions regarding expansion or contraction of ISOs with respect to LSEs? For example, under the NYISO tariffs and agreements, additional LSEs/utilities may join the NY control area by signing a service agreement under the Services Tariff. Of course adequate metering and communications must be in place. If an LSE in the NY control area wants to leave the control area, it must either (a) join another NERC-recognized control area, and if that control area is interconnected to the NYCA, it too must have an interconnection agreement or similar arrangements in place with NYCA; or (b) become its own NERC-recognized control area and enter into interconnection or similar arrangements with NYCA and any other neighboring control areas. These provisions on control area membership by all LSEs/utilities assures that they will directly or indirectly be responsible for all control area obligations and cannot lean on others.

E. Additional stakeholder-identified sub-issues generally under the Governance heading:

- Should the NERTO have full Section 205 filing authority on all issues affecting RTO duties and RTO operations, and should the RTO be required to make filings on behalf of the RTO SC upon the agreement of a two-thirds, sector-weighted majority under PJM voting rules as provided above?
- During the NERTO formation transition period to be established, should an interim group composed of existing ISO staff, under the direction of a transition oversight

authority (TOA) composed of two board members and the CEOs of each of the three NE ISOs, manage the transition to the NERTO? Should the TOA make decisions about NERTO-wide transition matters based upon consultations with state commissions and other stakeholders in the region?

- Should there be an interim nine- to fifteen-member Steering Committee, including CEOs of three ISOs (or designated representatives), and twelve other stakeholder representatives (with no more than three from any sector)?
- What are the mechanisms to ensure RTO board and staff accountability to market participants with respect to significant areas of responsibility, including: maintenance of reliability; efficient operation of competitive markets; responsiveness to stakeholder concerns; and cost control?
- What is the relationship between RTO and separate entities that establish reliability standards?
- What are the mechanisms to ensure that reliability standards, including local reliability rules, will be maintained throughout the RTO control areas?
- What are the provisions for a subregional reliability organization similar to the New York State Reliability Council?
- What is the relationship between the RTO and state regulators?
- What are the terms for the withdrawal of TO assets from RTO operational control?
- What are the appropriate limitations on liability and indemnity provisions?
- What should be the process for the selection of the RTO president?
- What are the initial staffing requirements of the RTO, including staffing for individual control centers?
- What are the mechanics for actual transfer of assets and control of transmission facilities and control centers?
- What is the plan for testing of systems (including software and computer systems) prior to actual RTO start-up?
- Should the Independent Market Operator ("IMO") have a governance structure based heavily on the PJM platform?
- Should the IMO operate the market(s), provide ancillary services?
- Should a transitional structure for organizing the creation of the Northeast RTO be established?
- Should the ISOs coordinate the development of the IMO, with steady reporting to all stakeholders?
- Should the Northeast RTO encourage participation by public power entities to the extent permitted by law?
- Should participation in the Northeast RTO by governmental entities be guaranteed?
- Is an interim governance procedure necessary or can we proceed immediately to the "permanent" governance structure?
- To the extent that the RTO is formed as a legal entity and begins start-up activities before an independent board is in place, how will the RTO be governed?
- If start-up activities begin before an independent board is in place and before the permanent stakeholder committee structure is established, how will the RTO's interim governance be structured to ensure independence and provide for stakeholder input?
- What actions will the interim management be permitted to take, and what actions will be deferred until an independent board is in place?
- What is the split of authority between an RTO, ISO, and an ITC?

II. Independent Transmission Companies

- How will ITCs be coordinated with the RTO and the transmission owners to ensure proper design and operation of the bulk power system?
- How will ITCs be created without causing inefficiencies such as intra-RTO pancaked rates, complexities and seams issues?
- How will expansion planning be coordinated between ITCs, the RTO, and the transmission owners?
- Should ITCs or any of their subsidiaries be permitted to own generation within the RTO?
- Should the Northeast RTO accommodate the development of ITCs, but with functional responsibilities remaining with the NERTO unless an ITC obtains FERC approval to transfer one or more responsibilities from the RTO to the ITC?
- How can the governance structure accommodate ITCs and other forms of transmission organizations?
- What are the role and responsibilities of an ITC within the RTO struc ture?
- Will the governance structure have an open architecture that will accommodate future structural change?
- Should a for-profit independent transmission company ("ITC") or an organization comprised of for-profit ITCs be established?
- Should this company or the constituent companies be governed by board(s) of directors and management(s) charged to uphold ordinary corporate fiduciary duties to their shareholders and reliability obligations to the interconnected grid?
- Should the ITC(s) be transmission owners who are not market participants?
- Should Transmission Owners who are market participants have an appropriately confined role for the management of their assets?
- Should they contract with the ITC, or an ITC, to perform the relevant functions for their assets?
- Should the ITC(s) be charged with driving the expansion of, and coordinating interconnection with, the transmission system, providing service to customers, and maintaining reliability of the assets under their control?
- Should an ITC, to the extent it shares responsibility with the Northeast RTO for any RTO functions, be required to satisfy all of FERC's criteria pertaining to RTOs?
- Should the RTO adopt an appendix to its governing agreement that sets forth which functions may be eligible to be shared with ITCs and the criteria for determining whether ITCs should share such functions? If so,
  - Should any shared functions remain under the oversight and final authority of the RTO?
  - Should any Board decision to allow a sharing of functions with an ITC be conditioned on substantive stakeholder input and subject to FERC approval?
- Should the Transmission owners coordinate the development of the ITC(s), with steady reporting to all stakeholders?
- Should there be an ITC? If so, how many?
- How many transmission tariffs would be administered by the ITC(s)?
- How much would it cost to create such ITC(s)?
- How much will it cost to operate ITC(s) on an annual basis?
- What benefits are ITC(s) expected to achieve?
- To what performance criteria will ITC(s) be held?
- Who will pay the start-up costs of creating ITC(s)?

- How will ownership terms be structured to minimize barriers to ITC ownership by public power and other non-jurisdictional entities?
- How will terms be structured to minimize barriers to non-ownership ITC participation by public power and other non-jurisdictional entities?
- Will the ITC be a stock corporation?
- If the ITC is a stock corporation, how many classes of stock will there be? What voting rights would attach to each class of stock?
- How will the Commission's restrictions on active ownership by market participants be implemented in the ITC?
- Will any ITC be a free-standing, fully staffed entity or will its functions be performed (in whole or in part) by existing Transmission Owner or ISO staff?
- What relationship would any such ITC(s) have to the Northeast RTO?
- Would the ITC(s) be considered a stakeholder or part of the RTO?
- Would an ITC be limited to ownership or operation of assets within the geographic boundaries of the single Northeast RTO?
- What responsibilities would the ITC(s) have? How would responsibilities be divided between the ITC(s) and other parts of the RTO?
- What legal relationships would exist between the ITC(s) and other parts of the RTO? Would there be a contract between the ITC(s) and the RTO?
- Who would be permitted to acquire an equity interest in the ITC(s) and on what terms?
- What rights would be given to those who transfer operational control of their facilities to an ITC but do not acquire an equity interest in it?
- How will the ITC be structured to facilitate the construction of transmission facilities by merchant providers/third parties?
- What will be the relationship between the ITC(s) and Transmission Owners that do not belong to the ITC with respect to revenue requirements and the RTO Transmission Tariff (including incentive rates, if any)?
- What kind of board would an ITC have (stakeholder, non-stakeholder, hybrid)?
- How many ITC board members would there be?
- How would initial ITC board members be selected?
- How will vacancies on the ITC board be filled?
- Can ITC directors be removed before the end of their terms? Under what circumstances? By whom?
- Will there be any limits on the scope of the ITC board's authority?
- Will any board decisions be subject to veto by ITC shareholders?
- Will there be any matters regarding which the ITC board is not permitted to vote?
- What voting rules will apply (e.g., allocation of votes, need for a quorum)?
- What fiduciary duties will ITC management have and to whom?
- Who may attend ITC board meetings? Will board meetings be open or closed?
- If board meetings are closed, what procedures will be in place to ensure that adequate information is disseminated to stakeholders?
- What obligations will the ITC board have to respond formally to stakeholder concerns?
- What fiduciary duties would ITC management have, and to whom?
- Will the ITC have a stakeholder advisory process and how will it be structured?
- What decisional role would stakeholders have (if any) in the management of ITC?
- What advisory role would stakeholders have in an ITC's decision-making?
- What ability will stakeholders have to challenge ITC actions expeditiously?

- How would stakeholders be kept apprised of matters the ITC board intends to consider at regularly-scheduled and special board meetings?
- Will stakeholders have an opportunity to review and comment on the ITC's proposed budget?
- Will stakeholders have an opportunity to review and comment in advance on drafts of filings the ITC intends to make with the Commission?
- How will the stakeholder advisory process be structured to ensure that both majority and minority stakeholder positions come to the attention of the ITC board?
- What responsibility will the ITC board have (if any) to respond formally to rejected stakeholder positions?
- Will an ITC be either encouraged or prohibited to expand geographically?
- Will there be any limits on an ITC's ability to diversify into other lines of business (e.g., telecommunications)?
- To the extent that multiple ITCs are part of the single Northeast RTO, what provisions will be put in place to encourage the ITCs to consolidate?
- What penalties will be imposed on the ITCs to the extent that they continue to act separately instead of on a consolidated basis?

III. Market Monitoring and Mitigation

- Should market monitoring and mitigation be done by the RTO and/or a separate organization, such as an independent organization or one hired by FERC?
- What roles should be played by an independent market monitor?
- How will the RTO ensure that wholesale rates are just and reasonable?
- How will the RTO identify market power and mitigate the exercise of market power abuse?
- How will the RTO adequately provide information publicly about its monitoring and mitigation activities?
- How should the RTO provide access to confidential information necessary for both the FERC and state regulators to carry out their responsibilities mandated by law?
- What will the RTO monitor and mitigate?
- What market mitigation process should exist for highly constrained areas such as New York City?
- How will the existing New York ISO market mitigation programs be incorporated into the RTO?
- How should the RTO get the necessary information to adequately address vertical market power in the region?
- Should NERTO establish a single market monitoring unit ("MMU") for the entire Northeast?
- Should the MMU incorporate the best practices of the existing ISOs, as identified by stakeholders?
- Should the MMU either be an independent separate entity under FERC authority or an independent unit within the RTO that is fully insulated from RTO management? In either case, should the MMU report directly (and only) to the FERC, Northeast State Commissions, and the RTO Board?
- Should the Market Monitor be an ITC/Transco, Non-Profit RTO or a third party?
- Should the IMO be the Market and reliability Monitor?

- Should the Market and Reliability Monitor ("MRM") be an independent non-profit institution charged with ensuring the integrity of the energy market and policing other decisions for inappropriately exercised conflicts of interest?
- Should this MRM also assume the duties currently performed by MAAC, NPCC and ECAR?
- Should the MRM be managed by a structure wherein all stakeholder interests are represented?
- Should the administration of ADR functions also be consolidated into the MRM?
- Should the FERC back up the MRM as an appellate body?
- Should committees representing all stakeholders negotiate the creation of the MRM?
- Should the Market Monitor include quasi-independence from the RTO as well as section 205 powers to submit additions and modifications to RTO tariffs to address or ameliorate market power and abuses?
- Should the Market Monitor have the power to sanction market participants for the market power or market abuses, but without the power to retroactively modify market results not obtained by fraud, collusion or by actions contrary to filed tariffs or market rules?
- Should the market monitor have meaningful enforcement powers and the ability to timely and directly compel production of data from market participants?
- Should the market monitor be obligated to coordinate its activities and share data with state regulatory agencies which have market-related responsibilities?
- Should the MMU have section 205 rights to file market power or market abuse related fixes to RTO tariffs?
- Should the MMU be obligated to respond to the request of the RTO or any members, federal or state agency to report on an alleged exercise of market power? Should such a report be made public and submitted to FERC without RTO, board or members review?
- Should the market monitor have the ability to timely and directly compel production of data from market participants?
- Should the market monitor be obligated to coordinate its activities and share data with state regulatory agencies which have market-related responsibilities?
- Should the market monitor have power to retroactively modify market results not obtained by fraud, collusion or actions contrary to filed tariffs or market rules?
- What are the RTO's responsibilities with respect to market monitoring including the ability to mitigate prices and assess penalties, and to address special conditions in different control areas and transmission constrained areas?
- What is the tariff language needed to implement market monitoring functions?
- What is the relationship of state regulators with respect to market monitoring?
- Is the market monitoring unit part of the RTO or independent?
- Will there be a mechanism included under Market Mitigation, which will enable recovery of costs incurred by harmed market participants as a result of intentional manipulation and/or market power by other market participants?
- Should market monitoring be independent, in both appearance and practice, from undue influence by stakeholders or any other party including the RTO management or Board?
- Should there be a single Market Monitor for the entire northeast region?
- Should the Market Monitor have the authority to detect market manipulation and the ability to monitor the real-time operation of the market?

- Should the Market Monitor have the authority to take deterrent action against market manipulation or market dysfunctions?
- Should the Market Monitor have mitigation authority regarding market manipulation or market dysfunctions?
- How should the Market Monitor ensure that the Northeast RTO is free of stakeholder influence?
- How should the Market Monitor ensure that the Northeast RTO operates in the public interest?
- How should the Market Monitor report on issues pertaining to the operation of all markets?
- Should the Market Monitor issue reports evaluating the operation of all markets to detect design flaws in the rules or procedures of the RTO?
- What should be the timing and frequency of Market Monitor reports?
- Who should provide the definitions used by the Market Monitor for market manipulation and market power?
- Should the Market Monitor be able to define the data which it needs to do its job?
- Should the Market Monitor be able to define how often and how quickly it will receive the data it needs to do its job?
- Should the Market Monitor have ready access to any data which it requires subject to confidentiality of the originator of the data?
- Should the Market Monitor be funded at a level which permits it to effectively complete its work as it defines that work?
- Should the Market Monitor have the authority to unilaterally act to seek market and rule modifications from FERC, as is currently the case in PJM?
- What level of sanction should the Market Monitor have the authority to unilaterally impose?
- Should the Market Monitor have complete editorial control of its reports?
- Should all reports from the Market Monitor to the Board and/or RTO Management be simultaneously released to stakeholders?
- How should reports which contain commercially sensitive information be provided to FERC or any other regulatory or government authority so that these offices may independently assess whether further investigation or action is merited?
- What are the data requirements that will be needed for market monitoring purposes for the NE RTO, including the following?
- What is the type of data needed for effective market monitoring purposes?
  - Operations (e.g. power flows; generator outages/derates; transmission line outages/derates; transformer outages/derates; PAR settings, outages/derates; schedules; transactions)
  - Market (e.g. LMP prices; transactions; curtailments; ICAP ownership, payments, and revenues; TCC/FTR ownership, payments, and revenues)
  - Billing (e.g. invoices, collateral, A/R)
  - Planning (e.g. congestion statistics, line capabilities, expansion plans)
- What are the various data sources? (EMS, Billing System, Market Information System)
- What is the speed/timeliness requirements of the various types of data to support an effective market monitoring and mitigation function?
- What are the tools needed for an effective market monitoring and mitigation process?
- What are the software requirements to support the following analytical functions?
  - Market replication (e.g. Day Ahead commitment, RT dispatch, LMP)

  - Congestion analysis (e.g. LMP sensitivity to contingencies)
  - Power system simulation (e.g. load flow)
  - General analysis (e.g. statistical, spreadsheet)
  - General office (e.g. word processing, presentation)
- How are the technology requirements for market monitoring and mitigation defined in terms of the following? (Hardware, Computers, Storage, Backup/emergency recovery, RT operations displays)
- What are the staffing requirements for the market monitoring unit?
- Among the skill sets needed for the Market monitoring unit the following should be included: economists, power systems engineers, analysts, financial expertise, data base programming skills, legal and anti-trust expertise.
- What are the specific monitoring responsibilities, authorities that the NE RTO market monitoring unit should have?
- What measures should be employed for the detection and mitigation of market power? RTO wide? NYC (special rules)? Temporary system congestion (NYC TSA, load pocket)? Retroactive vs prospective mitigation?
- What are the appropriate measures to be used for the detection of gaming and what corrective actions are appropriate?
- What should be the role of the Market Monitoring Unit in the detection of market flaws?
- Should the NE RTO have any temporary remediation authority (e.g. – similar to the NYISO's current TEP authority to issue ECA's?)
- Should the NE RTO, or its market monitoring unit have 205 authority to file for a tariff revision to correct market power abuse that is not specifically covered in its tariff?
- What is the NE RTO's responsibility/obligations regarding assuring price accuracy?
- What is the process for reservation of suspect prices?
- What is the process for correction of incorrect prices?
- What are the consultation requirements with market participants?
  - Prior to mitigation/penalties?
  - To address changes in bidding patterns?
  - To address unit outages/deratings?
- What are the reporting requirements related to the market monitoring function?
  - Periodic reports?
  - Special reports initiated by MMU?
  - Requests from stakeholders?
  - Requests from Board/RTO Management?
  - Requests from FERC?
  - Requests from other government authorities/regulatory agencies?
- What is the authority of the market monitoring unit to conduct:
  - General investigations?
  - Investigations to determine compliance with market rules?
  - Investigation of RTO monitoring/mitigation activities?
  - Investigations regarding ownership concentration?
- Should the NE RTO MMU have pre-approved mitigation authority based on bright line tests?
  - What are the markets and quantities subject to such mitigation?
  - What are the appropriate screens/thresholds to be used for automatic mitigation?

- Should the NE RTO MMU have the ability to impose sanctions/penalties?
- Should the MMU have the authority to make a FERC filing (with/without Board approval) for the following purposes:
  - To request data from market participants?
  - To request data from RTO operations?
  - To enforce compliance with market rules?
  - To analyze ICAP supply/purchase behavior?
  - To verify compliance with the obligation to offer energy/ancillary services?
- Should the NE RTO have the authority/obligation to make an antitrust filing on its own initiative?
- What are the rules for market participant challenges to MMU actions? (Internal review? Arbitration? FERC appeal? Legal proceedings?)
- What is the accountability of the MMU? (To the Board? To RTO management? To Market Participant committees? To Market Advisor?)
- What are the specific MMU Staff code of conduct requirements?
- What are the specific confidentiality requirements for the MMU?
- What is the scope of any MMU operations and procedures audits?
- Should there be an independent Market Advisor?
- What is the reporting relationship of the Market Advisor?
- What is the role and responsibility of the Market Advisor?
- What is the relationship of the Market Advisor with the MMU, RTO Senior Management, RTO Board?
- Will there be a market monitoring unit independent of the Northeast RTO?
- What process will the market monitor use to identify potential problems with the market or with market-participant behavior?
- What will be the scope of the mitigation authority of the market monitor and how will that authority be exercised?
- Will market monitoring and mitigation processes be automated or manual?
- Under what circumstances will the market monitor consult with stakeholders generally?
- Under what circumstances will the market monitor consult with individual market participants regarding specific behavior?
- What information will the market monitor compile concerning the operation of the markets generally (including the amounts and locations of congestion costs)?
- When and how will information provided to the market monitor concerning the operation of the markets generally be released to the stakeholders?
- What information will be made publicly available to allow the market participants to monitor the performance of the markets (i.e., what operational and participant bid/offer data will be made available and in what timeframe)?
- What information will the market monitor compile concerning specific instances in which the relevant screens or thresholds were exceeded?
- When and how will information provided to the market monitor concerning specific instances in which the relevant screens or thresholds were exceeded be released to the stakeholders?
- Should reliability compliance and enforcement continue to be independent of both the operation of the market, as well as, the market monitoring function?
- How will the RTO market monitoring function be coordinated with the reliability responsibilities of an independent organization which establishes and enforces criteria for the entire Northeastern North America?

- Should the RTO be authorized to adjust prices retroactively or prospectively when it determines market power or market flaws to exist?
- What provisions should be made for refunds that result from RTO or FERC ordered price corrections?
- Should the market monitoring unit (MMU) be an independent entity, not under the authority or control of the RTO?
- Should the MMU report directly to the FERC?
- Should the MMU have independent authority to propose tariff changes to address market problems?
- Should the MMU be designed as a data collection unit that submits the data directly to the FERC, with information copies only to the RTO?
- If the MMU assumes functions currently performed by the NERC sub-regions (such as MAAC and NPCC), will it also assume all NERC required functions?
- Should the RTO have the authority to determine penalties and sanctions for abuses identified by the market monitoring process and by FERC, or will this authority be left solely with the FERC?

IV. Recovery of Costs

- How should the system be designed so that those who benefit from RTO activities pay their share of RTO costs to avoid unnecessarily assigning those costs directly to load?
- How will costs be distributed in a manner that is fair and does not perpetuate economic inefficiencies?
- Should some costs be paid on a transactional basis?
- Should the RTO have control over recovery of its own costs by means of a tariff filed under Sec. 205?
- What methods should be used to ensure that RTO start-up costs are reasonable and reasonably allocated?
- How will the RTO's revenue requirement be collected?
- How much is it expected to cost to create a single Northeast RTO?
- How will the costs associated with the creation of the single Northeast RTO be recovered, and from whom?
- How much is it expected to cost to operate a single Northeast RTO?
- How will the costs associated with the operation of the single Northeast RTO be recovered on an equitable basis from all of the single Northeast RTO stakeholders?
- Who will be responsible for preparing a budget for the creation of the single Northeast RTO?
- What role will the shareholders play with respect to the budget for the single Northeast RTO?
- How much of the costs already incurred to create the restructured electricity markets in (a) PJM, (b) New York, and (c) New England will be stranded in the creation of a single Northeast RTO?
- How should such stranded costs be allocated and recovered?
- What role will stakeholders have in approving or commenting on the budget for a single Northeast RTO and/or its constituent parts (if any)?
- To the extent the single Northeast RTO includes an ITC (or ITCs), how will the costs of operating an ITC or ITCs be recovered?

V. Financing

- Should the RTO develop or adopt necessary arrangements to enable public power and investor-owned transmission owners with tax-exempt-financed facilities to joint an RTO without violating the tax-exempt status of their bonds (using the New York model as a best practice)?
- Should the RTO provide sufficient flexibility for RTO members that either are tax-exempt bond issuers or direct beneficiaries of tax-exempt bonds to take action as necessary to preserve the tax-exempt status of their bonds?
- Should finances, budget, and operations of the RTO be governed by the board with the advice of RTO members?
- What is the mechanism for funding RTO development and transition costs?
- How will the funding and recovery of RTO start-up costs be done?
- What capital structure requirements (including debt/equity ratio requirements) will be imposed upon the single Northeast RTO, including any related ITC?
- Will the RTO be required to maintain at least a specified minimum credit rating?
- What provisions will be put in place to ensure that the single Northeast RTO has access to sufficient funds to implement approved capital improvements?

VI. Credit Policies

- How will the RTO ensure the creditworthiness of market participants so that defaults are not unnecessarily passed along to consumers?
- What are the Payment Assurances and Credit Review for market activities?
- What are the Payment Assurances for other activities?

VII. Information Release

- What information will the market need to operate efficiently?
- How should the RTO provide access to confidential information necessary for both the FERC and state regulators to carry out their responsibilities mandated by law?
- How often and with what time lag should the RTO make all market bids and offers public via posting on its web site?
- How and when should emissions and other environmental impact information be collected and released by the RTO in order to facilitate compliance with state-level regulatory requirements and customer choice?
- In performing its activities, including market monitoring and mitigation, what information will the Northeast RTO (and any of its parts) consider confidential, and for how long will that confidentiality be maintained?
- How will the RTO make non-confidential information available to stakeholders?
- Will the RTO adopt a dispute-resolution mechanism in which stakeholders may challenge the treatment of certain information as confidential? How would such a mechanism operate?

APPENDIX A-2

Stakeholder-identified Sub-issues Pertaining to Market Design

I. Energy Market, Congestion Management, and Ancillary Services

A. Day-ahead Energy Market

- How will the RTO act to preserve reliability when the Demand that clears in the Day-Ahead Market ("DAM") differs from the RTO's forecasted Demand? How will the costs of preserving reliability in such situations be determined and supported?
- How will the software that runs the DAM and performs the rest of the Day-Ahead ("DA") unit commitment recognize and accommodate multiple transmission constraints, ramp rate constraints and ancillary services obligations in the determination of DA Locational Marginal Prices ("LMPs")?
- Will the RTO reflect bilateral transactions in its settlement systems and, if so, what flexibility will be available to market participants as to the types of transactions that the RTO will be equipped to recognize (as opposed to being left to bi-lateral settlement)?
- Will there be a physical priority or an economic priority used to schedule external transactions with neighboring RTOs?
- What RTO costs will go into "uplift" and how will the uplift costs be allocated?
- What costs associated with Reliability Must-Run ("RMR") resources will be reflected in the LMPs and what costs will be socialized, either globally or locally?
- How many trading hubs will there be?
- Should unit commitment be done on an aggregate market basis?
- If load will have the option to pay a zonal price for energy and ancillary services, what methodology will be used to determine the zones?

B. Real-time Energy Market

- Will the Real Time Market (RTM) for energy be operated at one location for the NE RTO? If not, how will energy prices and congestion in the RTM be managed to match up with the DAM?
- Should Real-time economic dispatch be performed on an aggregate market basis?
- Will the balancing market operate on an integrated hourly basis or on some shorter time interval (e.g., determination of balancing energy obligations and prices on a ten-minute basis)?
- What flexibility will market participants have to change their bids, offers and schedules in Real-time?
- How will the dispatch of fast start resources be reflected in the Real-time dispatch and the determination of Real-time LMPs?

(Energy Markets, Generally)

- Should the NE RTO adopt a single energy market design, including a single method for calculating energy prices? If so, on what schedule should this single market design be implemented? What changes are necessary to implement such a single market design?

- How will load and generation balance in the control areas be maintained in the single market? How will the NE RTO design assure that centralized economic dispatch signals do not conflict with local or central AGC signals?
- Should the Standard Market Design be implemented in New England prior to completion and implementation of a single market design for the Northeast?
- What are the differences between NYISO's LBMP market and PJM's LMP algorithms? Which design or combination is the "best practice?"
- Is the market design to be a "voluntary poolco" model which provides for central dispatching but permits bilateral transactions to self-schedule?
- Will bilateral transactions be required to submit balanced schedules?
- Should there be a market clearing price calculated under all conditions?
- Will the dispatch of resources be based on: (i) the issuance of price signals (to which the resources will be expected to respond by moving to their individual corresponding MW level); (ii) the issuance of dispatch instructions to move to specific MW levels; or (iii) some other methodology? In any event, will the method be based on electronic or verbal communications?
- Should a least-bid-cost dispatch be used?
- Should the dispatch method be based on price or quantity?
- Should there be a bid production cost guarantee and how is it computed?
- Are bid caps necessary in any/all markets and what is the appropriate level?
- Should bid caps be both positive and negative?
- Should "virtual bidding" be permitted for both loads and generators? If so, what is the "best practice" for virtual bidding?
- Should trading hubs be established and where?
- What are the appropriate proxy buses for external control areas?
- Are marginal losses to be used in dispatch?
- Are marginal losses to be used in pricing?
- What are the rules for pricing of fixed-block generation (e.g., CT's)?
- Should there be a provision for "price taking" self-dispatch?
- Should there be a requirement for incremental and decremental bids from all generators?
- Should "e-schedules" be part of the energy market design? What is the best practice design for e-schedules?
- How are Lost Opportunity Costs accounted for in the various markets?
- How are start-up and minimum generation costs accounted for?
- What are the required characteristics of the generator bid curve (e.g., point-to-point, monotonically increasing, curve fit techniques, etc)?
- Will there be an Hour-Ahead evaluation process?
- Will the Hour-Ahead process be manual or automated?
- Will the Hour-Ahead process be advisory only or produce binding financial commitments (i.e., result in market settlements)?
- Will the Hour-Ahead process (market) apply to both internal and external transactions?
- Should the market design include simultaneous optimization of energy and reserves bids? If so, what are the rules for the simultaneous optimization process?
- If it is necessary to maintain sub-markets or zones within the northeast RTO region, should all have the same market rules?
- Shouldn't market designs have the objective of achieving price transparency?

- Are price caps or other similar market mechanisms necessary in the development stage of the northeast RTO region markets? Should they otherwise be established where market power is exercised?

C. Financial Transmission Rights

- How should the rights to use transmission capacity be determined, and how will the fixed costs of owning and operating the transmission system(s) be recovered?
- Will financial congestion hedge instruments (FTRs/TCCs) be sold across the region comprising the NE RTO?
- How will the congestion costs be calculated across the multiple control areas?
- Will Existing Transmission Agreements (and other forms of grandfathered rights in the various control areas) be continued as transmission rights or converted to FTRs/TCCs? Will such conversion be mandatory or voluntary? Will such conversion have a drop-dead date for exercise of that right?
- Will payments on congestion hedge instruments be fully funded (TCCs in NY) or subject to financial reduction (FTRs in PJM)?
- Will transmission losses be calculated and priced on a marginal basis (NY) or on a fixed basis (PJM)?
- How will congestion costs appearing across multiple control areas be allocated to the TCCs/FTRs which may be both local to a control area and span multiple control areas?
- Will FTRs/TCCs be sold at auction only, allocated to parties purchasing Firm Transmission Service, or both?
- If both, what is the interaction/priority between the two types of FTR's/TCC's?
- Will TCCs/FTRs be sold at auction for short-term periods only (PJM) or for periods of longer duration (NY)? How will the duration period for TCC's/FTR's be determined/updated?
- Will TCC/FTR auctions be sequential or simultaneous?
- How will the revenues from the FTR/TCC auction be distributed?
- What is the methodology for the determination of available FTR's/TCC's (e.g., demonstration of simultaneous feasibility)?
- Should the approach to managing congestion take into account the location of the resources used to serve load and the location of the load?
- Should existing FTRs or similar congestion mitigation vehicles be grandfathered and continued?
- Should the congestion management system be based on the FERC-endorsed PJM Locational Marginal Pricing method, including Financial Transmission Rights?
- Should the Transmission Owners, to the extent they have the initial rights to use transmission, be required to offer those rights for sale? If so, what portion of their rights must be offered and for how long? Should the offering be made in an auction or some other process? Should these rights be offered in the form of hedges (e.g., Transmission Congestion Contracts)? Should such rights be obligations or options? Should existing transmission rights be grandfathered? If so, how?
- Should the NE RTO adopt TCC auction approach used by NYISO in which all TCCs are made available for auction and proceeds are distributed to reduce the revenue requirement of the Transmission Owners?
- Do current practices regarding congestion management meet the Order 2000 requirement that the RTO work to mitigate transmission congestion?

- Will zonal and/or nodal pricing be employed and how? Will FTRs only be node to node, or will FTRs also be allowed between other combinations of nodes, zones and trading hubs?
- How will existing transmission rights under each ISO be treated? Will grandfathered treatment of pre-ISO transmission contracts in the respective ISOs be recognized and continued under the NE RTO? Will TCCs/FCRs awarded under the respective ISOs be recognized and continued? If so, how will these instruments be made available to the market (e.g., RTO administered auction)?
- How will transmission rights be formulated under the RTO? Transmission rights as obligations versus options; Transmission rights inclusion in Day-ahead market only; Term of transmission rights; Allocation for transmission rights/incentives for availability or capability improvements; Allocation of revenue from TCC/FTR sales; Inter-control area transmission rights?
- How will congestion rent excesses and shortfalls be treated?
- How will inter-control area congestion be treated?
- Will there be an FCR auction? How often will auctions be conducted? Will the auctions be region-wide? How will FCRs be allocated? How will the FCR auction revenue be allocated?
- Will congestion rights be allocated based on the DAM run at one location? If not, what will Congestion rights be based on?
- Will there be FTRs or other instruments associated with Real-Time LMPs (i.e., will there be any means for participants to hedge Real-time congestion)?
- What mechanism will be used to facilitate an inter-RTO rights market to encourage transmission expansion?

D. Financial Rights Allocation/Auction

- How will the allocation/auction mechanism recognize pre-existing contractual and settlement rights associated with both point-to-point and network service, including service associated with system power contracts?
- Will there be any shorter-term (e.g., weekly, daily, hourly) auction of FTRs that may be made available due to shorter-term system conditions?
- Will the RTO operate a secondary market for trading FTRs?
- What is appropriate treatment of Independent Transmission Companies (“ITCs”) with respect to the allocation of FTRs / TCCs?

E. Regulation Market

- Will there be an obligation to provide regulation services?
- Should there be a regulation market(s)? If so, what market structure should be used?
- If there is no regulation market, how will regulation be obtained by the RTO, and how will generators be compensated for any regulation provided?
- How will load and generation balance in the control areas be maintained in the single market? How will the NE RTO design assure that centralized economic dispatch signals do not conflict with local or central signals?
- How will the Regulation requirement, including any locational aspect, be determined?
- How will the total Regulation responsibility be assigned to the market participants?
- Will market participants be able to self-provide their Regulation responsibility?
- What will be the form of Regulation bids?

- How will the price to be paid to Regulation providers, including any locational aspect, be determined and how will the costs be recovered?
- What will happen when a provider of Regulation in the DAM fails to provide the Regulation in RT? In such an instance, what will be the impact on (a) the provider who failed to provide; (b) the replacement provider; and (c) other market participants?
- Will market participants be allowed to trade Regulation with market participants in neighboring RTOs?
- What type of regulation market will be economically sound and reliable, plus produce a cost benefit for the LSE?

F. Reactive Services

- How will voltage support services be procured?
- Will there be minimum reactive power obligations placed on generators and, if so, how will they be determined?
- Will there be minimum reactive power obligations placed on loads or distribution companies and, if so, how will they be determined?
- Will there be a locational aspect to the reactive power services?
- Will market participants be able to self-provide their reactive power obligations?
- Will the "load ratio share" used to allocate costs to "transmission service loads" include service to Wheeling Through and Wheeling Out transactions?
- Should transmission be paid reactive service charges for the transmission reactive service provided?

G. Operating Reserves

- Will there be an Operating Reserve market or some other approach to Operating Reserves?
- What categories of Operating Reserve will be utilized?
- How will the Operating Reserve requirements, including any locational aspect, be determined?
- How will the total Operating Reserve responsibilities be assigned to the market participants?
- Will market participants be able to self-provide their Operating Reserve responsibilities?
- What is the form of Operating Reserve bids?
- How will the price to be paid to Operating Reserve providers, including any locational aspect, be determined and how will the costs be recovered?
- What will happen when a provider of an Operating Reserve in the DAM fails to provide the Operating Reserve in RT? What will be the impact on the provider who failed to provide, the replacement provider and other market participants?
- Will market participants be allowed to trade Operating Reserves with market participants in neighboring RTOs?
- Will there be a "Demand Curve" associated with Ancillary Services, pursuant to which the quantity required will be reduced as the cost goes up?
- Should there be a spinning reserve market(s)? If so, what market structure should be used?

- If there is no spinning reserve market, how will spinning reserve be obtained by the RTO, and how will generators be compensated for any spinning reserve provided?
- Will there be an obligation to provide spinning reserve?
- Should there be a non-spinning reserve market(s)? If so, what market structure should be used?
- If there is no non-spinning reserve market, how will be non-spinning reserve be obtained by the RTO, and how will generators be compensated for any non-spinning reserve provided?
- Will there be an obligation to provide non-spinning reserve?
- Will both generation and load be able to provide non-spinning reserve?
- Can reserves markets provide adequate incentive for long-term capacity and, if so, how?
- Should a "replacement reserves" market be created?
- Will lost opportunity costs be paid for operating reserves?
- How will locational operating reserves be compensated?
- How will operating reserves be optimized?
- Should the NE RTO develop and operate forward markets beyond the Day-ahead (i.e., week-ahead, month-ahead, year-ahead)?

H. Control Areas

- How many separate control areas are envisioned initially?
- How often will the schedules between control areas be "dynamically" updated?
- How long will the separate control areas be maintained, and how will this be determined?
- What is the appropriate allocation of the RTO's administrative costs among the various services that it provides?
- How are the RTO's costs allocated among various market participant sectors?
- What are the billing determinants to be used for the allocation of these costs?
- Is the rate for such costs uniform throughout the year, adjusted on a monthly basis, trued up periodically?
- Is the rate a formula-based rate or must it be filed on an annual basis?
- Are there any incentive provisions applicable to this rate?
- Are there any "uplift" components to this rate or are such costs tracked separately?
- Where/how are such uplift payments allocated/collected?
- How will unit commitment and dispatch be accomplished? Who will provide this service? Will there be a single unit and commitment dispatch process for the entire Northeast? What are the advantages and disadvantages relative to separate commitment and dispatch models for the current control areas? Are there software or system limitations that limit the size and scope of optimization problems given time requirements? What are the comparative costs? How much time is required to develop systems necessary to support a single market system? What dispatching practices and time schedules will be employed?
- Will there be one control area dispatch for the whole RTO with "local" reliability security functions like reliability satellites?
- How will external ties and resources be treated? Should current reservations on ties between the control areas be maintained?

- Will the market design include regional variations to accommodate different state retail access programs, or will individual states be expected to amend their retail regulations to conform to the RTO wholesale market design?
- Will the RTO market design allow for any sub-regional variations to accommodate geographical differences? If so, what criteria will determine is such a variation is warranted?
- Can reserve objectives be net across the RTO rather than each ISO to reduce costs to end-users, while still maintaining three separate ISOs?

I. Parallel Path Flows

- What role should the NE RTO play in dealing with parallel path flows?
- How should phase angle regulators (PARs) be set and controlled in the NE ISO? Should they be optimized?
- Should the NE RTO internalize parallel path flows within the region using the LMP method?
- How should redispatch and cost sharing related to parallel path flows be handled by the NE RTO?
- How should the effect of parallel path flows on FTRs/TCCs be handled? Will the determination of simultaneously feasible FTRs reflect the reservation of any transmission capacity to accommodate expected parallel path flows?

J. Demand Response

- What is the proper role for a NE RTO relative to demand response programs? Should the RTO offer distinct programs to direct customers or act as program facilitator for LSE programs?
- Should there be a single program across the RTO or multiple programs in each control area/state jurisdiction?
- What role should the state PUCs play in facilitating demand response?
- What are the jurisdictional implications of a demand response program under a FERC-regulated RTO tariff vis-a-vis state retail jurisdiction?
- What is the impact of retail rate design policies on RTO demand response programs?
- What type of coordination is required with LSE programs?
- Should participants be paid for demand response, or simply save the cost of the energy they would have consumed?
- What is the basis for determination of payments for demand response programs?
- Where do demand response products fit within the market (e.g., Day-ahead energy, ancillary services, emergency demand reduction, Real-time pricing, etc.)?
- Will Demand be allowed to offer ancillary services and, if so, under what conditions?
- Should Emergency Demand Response Programs qualify as operating reserves and/or installed capacity?
- What are the verification/control and monitoring requirements for such programs?
- How should demand response be modeled within Day-ahead and/or Real-time scheduling software?
- Can demand response program bids set the market clearing price for energy?
- Should participant demand response be voluntary or mandatory (e.g., via price penalties)?
- How should emergency diesel generation be treated in demand response programs?

- How are the environmental impacts of such programs handled?
- Who should be allowed to offer demand response products in the marketplace (LSEs, service aggregators, direct ISO/RTO customers)?
- What are the requirements for participation (e.g. – minimum size, rules for aggregation, credit requirements, etc.)?
- Should there be a separate customer classification for certain types of demand response programs (e.g., limited status for emergency demand response programs)?
- How will the performance of responsive Demand be monitored?
- What are the metering requirements for demand response programs? Who can install meters? Who can read meters?
- How to measure demand reduction – load shapes vs. customer baseline calculation?
- What are the specifics of the load shaping / customer baseline calculation method?
- Who is responsible for testing, verification and audit of demand response (RTO or TO's)?
- What are the time frames for collecting demand reduction data?
- What are the relative responsibilities of the RTO, TO's, and LSE's?
- What are the billing, accounting and settlement requirements for demand response programs?
- If payments are to be made to demand response program participants, what payment levels/rules should be established?
- How should demand response program costs be allocated to market participants (all loads in RTO, statewide, by control area, by utility area, other)?
- What are the market monitoring and mitigation requirements for demand response programs?
- How do demand response programs impact the environment?
- Must the RTO sponsor price response programs designed to ensure reliability and to improve the efficiency of markets? Should the RTO implement both emergency programs and economic programs? Should emergency programs be administered separately from economic programs where necessary?
- Should participation in RTO price response programs be open to all RTO members?
- Should RTO membership include a special category for members who intend to participate only in these programs? Should this category of membership be non-voting, bear corporate liability reflecting the member's participation only in DSR programs, and have a minimal fee?
- Should each participant be permitted to enroll in both emergency and economic price response programs?
- Should metering requirements be addressed through a standard methodology throughout the RTO so as to permit broad, expanded, cost-effective participation in load response programs?
- Must the RTO analyze all new DSR programs to determine the extent to which they benefit reliability and economic efficiency of markets. RTO members should be required to collaborate with the RTO staff in evaluating DSR programs?
- Should demand side management mechanisms be implemented?
- Should the RTO facilitate the use of load response programs to meet the needs of customers and energy suppliers to control costs, and to meet the need of system operators to have tools to maintain system reliability?
- Should companies be adequately compensated for their administrative services?

- Should the RTO establish rules for using load response programs to obtain credits against generation reserve requirements, establish rules for reporting compliance with load response program requirements, and establish penalties for any non-compliance?
- In the long term, should the RTO foster the increased use of Real-time price signals to customers to establish a full price responsive electricity market where both supply and demand curves are a function of price?
- Should the NE RTO adopt the existing PJM demand-response program?
- Should the NE RTO affirmatively pursue load response programs (where consumers reduce consumption in response to high supply prices) as a market mechanism to reduce volatility in energy market prices?
- Should the NE RTO provide emphasis and immediacy to developing load response programs including using incentives that can overcome historical barriers to customer responsiveness to Real-time market prices?
- Should the NE RTO identify and eliminate barriers to small customer participation in load response programs?
- Should the NE RTO encourage both economic and emergency load response programs open to all customers? Emergency programs, where the RTO calls for load response, enhance reliability, while economic load response programs encourage greater customer responsiveness to market price?
- Should the NE RTO have not less than two general categories of economic load response programs: those that allow load response bids to set energy market price; and those that allow a customer to respond to Real-time market prices with load response?
- Should the NE RTO examine fixed customer load profiles and develop a strategy to eliminate the lack of Real-time price signals these fixed profiles impose on non-interval metered customers?
- Should the NE RTO encourage load response that minimizes environmental impact of generation and transmission facilities?
- Should the NE RTO develop programs for the use of customer sited or distributed generation where the customer can offset its own loads and export excess power to assist the grid?
- Should the NE RTO consider load response as a necessary market element on an equal basis with generation and transmission?
- Should the NE RTO encourage load response programs that allow aggregated small customer participation?
- Should the NE RTO encourage aggregated customer load response allowing an incorporated local government and other geographically defined entities to act as load response aggregators?
- Should the NE RTO develop methods to properly measure the load response of aggregated groups of small customers participating in RTO load response programs? Such methods may rely in part on RTO transmission and sub-transmission metering and other metering information available to the RTO and used in combination with statistical analysis.
- Should the NE RTO allow and encourage customers participating in existing automated load management programs (by contract or otherwise) to participate in RTO load response programs provided such participation does not breach said contractual obligations?
- Should the NE RTO investigate and implement metering and statistical measuring methodologies that measure a customer's load response under any RTO load response programs and allow customers to participate in RTO load response programs at as

minimal cost to the customer as practical? Metering for load response programs may be separate and apart from metering used for retail energy consumption and billing.

- Should the NE RTO allow load response programs to be implemented with incentives above market prices, provided those incentives are aimed at eliminating historical market barriers or identified market defects?
- Should the NE RTO establish a program of data collection on the efficacy and environmental impacts of any load response programs implemented and should implement methods for the expedient adjustment of non-functioning programs?
- Should the NE RTO solicit the input of stakeholders into the development of load response programs but should discount the opinions of market participants, if, in the opinion of the RTO, the position of the stakeholder is promulgated to advance that stakeholder's market position?
- Should the NE RTO develop a capacity market for load response provided the load response supplies a service equal or equivalent to those capacity services provided by generation owners?
- Should the NE RTO identify and develop programs to allow load response to provide ancillary network services including, but not limited to, spinning reserves and provide compensation mechanisms for the value of these services?
- Should loads be able to participate in all markets for which they are eligible?
- Should loads be allowed to bid curtailability in Day-ahead or Real-time markets?
- Should the NE RTO adopt Day-ahead and emergency response programs consistent with best practices?
- Should demand response programs be pursued aggressively?
- How will price responsive and command responsive load/distributed generation be accommodated? How will participation be verified?
- Should the NE RTO allow electric customers to respond to market signals through load reduction, curtailment, fuel switching, generation, energy-efficiency, and other technologies?
- Should demand-side resources be included in the wholesale market design for the NE RTO? If so, should distributed, customer-owned or inside-the-fence generation should also be considered a demand-side resources?
- Should the NE RTO initially adopt the current “best practices” of each ISO regarding demand-side programs while working to develop new demand-side programs that will be informed by the lessons learned from the current programs?
- Should the NE RTO, to the extent that it includes wholesale markets for energy, capacity and ancillary services, provide demand-side resources opportunities to participate in those markets that are at least comparable to those of generators?
- Should the NE RTO encourage the participation of loads and load serving entities in the regional retail markets for energy, capacity, and ancillary services and should facilitate such participation, consistent with its scope and mission?
- Should the NE RTO encourage both emergency (RTO directed) and price-responsive (customer-directed) demand response programs?
- Should the NE RTO consider and where appropriate implement incentives for demand-side resources to raise them from their current “infant industry” status to substantial contributors to the region’s resource needs. Such incentives should consider the lessons learned from existing ISO programs?
- Should the NE RTO reduce barriers to the development, construction, interconnection, and operation of distributed generation facilities and other demand-side resources that have the effect of reducing load, particularly during peak periods?

- Should the NE RTO ensure that installed reserve margin requirements (if any) appropriately reflect the contribution of reliable reductions in peak load? Peak load reduction programs should receive adequate credit in the market for installed capacity.
- Should full "load response markets" be developed to replace current load response "programs?" If so, how would they be structured?
- Should the RTO implement one or more technology solutions (such as internet notification and metering) to facilitate the implementation of demand-side options?
- Should there be technology platforms for RTO demand response programs?
- Should incentive payments for clean fuel or conservation technologies (i.e., natural gas, solar, high efficiency, etc.) be designed in the NE RTO demand response program?
- Should the NE RTO forecast long-term LMPs and provide a net present value incentive (e.g., 10 years) to demand response projects in order to spur their development? (Such projects could forgo payments for services provided for ten years plus or minus a true-up.)

K. Generation Information System

- Should the NE RTO implement a GATS similar to the one being developed by PJM?
- Should the NE RTO implement a GIS similar to the one being developed for ISO New England?
- Should all generation (including small and behind the meter generation currently not recognized in the wholesale market systems) be covered by a GATS/GIS?
- How should imports, exports, line losses and pumped storage generation be treated in a GATS/GIS system?
- How should the exchange of certificates be handled in a GATS/GIS system?
- How can we develop a system that will enable verification and compliance with state regulatory requirements including renewable portfolio standards, disclosure and labeling requirements, and emission performance standards in a least cost manner and mitigate the administrative burden on market participants in complying with the various state regulatory requirements?
- How can we develop a system that will facilitate consumer access to electricity products with preferred attributes, liquidity in markets for renewable and clean energy, product differentiation in the marketplace, and purchases that consider the environmental attributes of electricity?

L. Financial Settlements

- Should the RTO provide participants with the opportunity to balance energy in Real-time?
- To what extent should market rules and procedures be designed and implemented to accommodate the operational characteristics of various types of generation units (e.g., intermittent generation units)?
- To what extent should multi-settlement systems (Day-ahead, Hour-ahead, Real-time, etc.) accommodate small, behind-the-meter generation?
- How many and what types of settlements should be implemented? How do we ensure separate settlements are relatively consistent?
- How will market clearing prices be determined? Day-Ahead? Real-Time? Location-Based? Region-wide? As-Bid?

- Will resources be eligible for "uplift" payments? If so, how will eligibility be determined? How will costs be allocated?
- Should Locational Based Marginal Prices (LBMPs) and Financial Congestion Rights (FCRs) be used for congestion management? Will zonal and/or nodal pricing be used? Will there be congestion uplift?
- Will there be a single Northeast settlement system, or will separate settlement systems be retained?
- Will the same system be used for the DAM, RTM, system scheduling, dispatch, and settlements?
- Will transmission tariff settlements and market settlements be separate?

M. General Comments

(General Principles)

- Are market-based solutions preferable to command and control solutions?
- How should market design elements should be made congruent with reliability concerns?
- How should market design elements be structured to best serve the public interest through the creation of economic efficiencies?
- How should symmetry be achieved between demand-side and supply-side market solutions?
- Should a phased transition to control area consolidation be used so as not to interfere with security functions?
- Should the entire NE RTO adopt a single congestion management system?
- What is the best method for adopting the best practices from NYISO, NE ISO, and PJM West and applying them to the PJM platform?
- How should market mechanisms be used to assure capacity adequacy, and how can those market mechanisms eventually be merged into a uniform system?

(Environmental Issues)

- How will environmental considerations be addressed, including the implementation of state and federal environmental regulations?
- Should the NE RTO adopt an "environmental policy statement" similar to the one adopted by NY-ISO that states that environmental impacts will be considered in all policy and rule-making decisions?
- Should the environmental benefits of renewable generation be quantified and incorporated in the market rules and procedures?
- Should market rules employ a tie-breaking mechanism to favor lower emission generators when selecting between units with identical bid prices?
- Will some generation have an advantage because they are located in a state that has less restrictive laws?

(Ancillary Services, Generally)

- What, if any, ancillary services markets should be established and how should they be structured? What ancillary services markets, if any, should be administered by the NE RTO?

- Should ancillary services be market-based or cost-based? What market conditions are necessary to support effective market-based pricing of ancillary services? As an intermediate measure, MAPSA recommends a cost-based or incentive-based approach to the ancillary services market until products and costs can be appropriately unbundled and it can be proven that a well-developed market exists.
- Should uniform ancillary services be required locally or on uniformly across the entire NE RTO? If locally, what are the differences between localities? Who will make the determination?
- What is the cost allocation for ancillary services: region-wide or locational?
- Should market-based ancillary services bids be simultaneously optimized with energy bids under a least-bid-cost dispatch?
- Should ancillary services markets be sequential? If so, what is the appropriate order of these markets?
- Should self supply of ancillary services be permitted? If so, how should self-supply be coordinated with the RTO's market based ancillary services?
- If possible, should a single market exist for all ancillary services (recognizing separate markets may be necessary for specific ancillary services)? Consider reactive service, which tends to be localized in nature.
- How should pancaking of ancillary services be addressed? Can pancaking of ancillary services be eliminated during the transition period?
- MAPSA is concerned that all three ISOs have not properly addressed ancillary services. Looking to PJM as a platform, the business plan should recognize the need to further unbundle and develop ancillary services markets within the PJM platform.
- How will ancillary services be procured; and will the commitment and dispatch algorithms optimize use of transmission for both energy and ancillary services?
- How will costs be allocated for each type of ancillary service?
- How will lost opportunity costs for providers of ancillary services be created?
- What, if any, performance penalties for ancillary services will be invoked?
- What type of regulation and frequency control market will be needed?
- How will black-start services be procured?
- Will operating reserves and regulation be provided through a competitively bid market?
- How will ancillary services requirements be determined? Will the requirements be locational and/or priced locationally? Will requirements address deliverability? Will requirements be static or dynamic? Will load pocket requirements for ancillary services be included?
- Will energy providing "replacement reserves" be explicitly included as an ancillary service?
- What other ancillary services are required? How will they be obtained? How will providers be compensated and costs be allocated?
- Should we proceed with non-FERC identified ancillary services (transmission auxiliary services) such as black start?
- Should there be a single northeast RTO-wide market for ancillary services?
- If a competitive market for ancillary services does not exist, should the RTO have the authority to order generators within the northeast RTO to provide ancillary services at cost-based rates? Is it appropriate to put price caps in place, at least in the early stages of the ancillary services market?
- Should the RTO designate specific must-run generators?

- Should the variety and type of ancillary services or interconnected operations services be expanded? For example, should such services include black start? Should such services be standardized for the entire northeast RTO?

(Costs of Operation)

- In developing all aspects of the single RTO, must the reduction of cost to end users be the primary goal over as short a period as is reasonably possible?
- Should the RTO administer a uniform energy and congestion management system?
- Should duplication of administrative costs (for example, scheduling activities) be reduced/eliminated as quickly as possible?
- Should there be guidelines for RTO cost control?
- Who should pay for marketing activities – transmission customers, power sellers, buyers, or all?
- How will the administrative and operation costs of the RTO/ISO be managed?
- What will be included in uplift charges?

(Market Power Monitoring and Mitigation)

- Should the RTO be responsible for supporting workable, transparent and unbiased markets and, where necessary, for placing controls on markets which are dysfunctional or where market power is present?
- Where competitive markets for ancillary services do not exist, the RTO must have the authority to order generation owners within the RTO boundaries to provide these services.
- Should market monitoring be more active, objective and prompt?
- Should there be any protection against market manipulation?
- Should there be penalties and sanctions for market manipulation?
- Should the markets (energy, ancillary services, capacity, etc) be structured to discourage the abuse of market power? If so, how? How should markets be structured to facilitate market monitoring for, and appropriate mitigation of, market power abuses? If so, how?
- How will market monitoring and compliance be performed?
- What, if any, market mitigation tools (e.g., bid caps or other price controls) must be available to ensure effective mitigation of market power throughout the RTO and/or on a locational basis? What level and type of customer service/support/training and market data postings will be required?
- Should market monitoring that is independent of the NE RTO be used?
- If the NE RTO performs the market monitoring function, should independent audits of market design and/or operation be performed to evaluate not only market behavior but also the NE RTO's role in influencing that behavior?

(Congestion Management)

- Should a single congestion management system be implemented across the entire RTO? Should it be based upon an LMP approach? How can the tools and products available to hedge against congestion be improved? Should hedging mechanisms be standardized for the entire northeast RTO?

- Should the congestion management system for the RTO be based on locational marginal pricing (LMP). LMP systems must be consistent in design, operation and pricing principles across the northeast region.
- Should congestion management systems allow for compensation of distributed resources in congested load pockets?
- Should congestion management systems provide a level playing field for all generation resources and not unfairly discriminate against particular generation resources?
- Should revenues collected pursuant to congestion management pricing be distributed in a manner which includes financial incentives to relieve transmission congestion through beneficial transmission, generation and demand side investment and behavior?
- Should all existing transmission contracts continue to be grandfathered?
- Should a less expensive, less confusing and more manageable congestion management system rather than LMP be implemented?

(Imbalance Service)

- What are the rules for balancing service?
- How is imbalance calculated (e.g., difference between the actual Real-time energy deliveries and Day-ahead scheduled deliveries, on an hourly basis)?
- How is imbalance service priced (e.g. – at the Real-time LBMP, hourly, every dispatch interval)?
- Are there any penalties associated with imbalance?
- How are these penalties determined (e.g., pro-forma, dead band, ability to reconcile, time period to reconcile, reconciliation in kind, financial true up)?
- What are the provisions for inter-control area imbalance (within the RTO/with external control areas)?
- Are there differences in imbalance among the various control areas, reliability councils and how are they to be reconciled?

(Other)

- Should RTOs handle both transmission service and power markets?
- How should the markets be structured to best take into account unique or local operating conditions and constraints such as those related to local reliability, compliance with environmental restrictions, and other unit operating characteristics such as those of energy limited resources (ELRs - such as pumped storage facilities) and capacity limited resources (CLRs -- units that can provide short term additional output in emergency situations)?
- The business plan should recognize, prioritize and schedule deadlines for the work currently being pursued in this regard by PJM's Cost Development Task Force.
- ICAP and ancillary services markets should provide access for small generators.
- Market rules must address deviation penalties in a manner not unduly burdensome for intermittent resources.
- Intermittent generation resources in the entire control area must continue to be eligible for treatment along the lines of existing market designs in PJM and NYISO that recognize the unique operating characteristics of intermittent generation resources.

- How do the individual markets interact between each other, and what steps need to be taken to ensure consistency and appropriate coordination?
- What creditworthiness criteria are needed?
- How will the market design accommodate existing and anticipated contracting forms including: Bilateral contract structures; "Asset-based" contracts for either load obligations or generation resources; Long Term contracts entered into on prior market designs/structures?
- Will the market design include regional variations to accommodate different State retail access programs, or will individual States be expected to amend their retail regulations to conform to the RTO wholesale market design?
- Will the RTO market design allow for any subregional variations to accommodate geographical differences? If so, what criteria will determine if such a variation is warranted?
- Is standardized software needed, or is software that integrates seamlessly acceptable? How will new or standardization of software be justified?
- How will Load Modifiers be handled?
- How should load forecasting be done?
- What commitment technique(s) should be used and which resources should be subject to centralized commitment?
- What dispatch technique(s) should be used and which resources should be subject to centralized dispatch?
- What are the appropriate terms and structure of market bidding program: Identification of bidding requirements, Time frames for market closing and posting, Use of multi-part versus single part bids, Use of bid guarantees, Recognition of operating constraints in the bidding structure?
- How will the cost of losses be incorporated?
- How will bilateral transactions be evaluated, scheduled, and curtailed?
- How will inter-control area transactions be handled?
- How will TLR procedures be invoked?
- How will transactions with control areas external to the RTO be scheduled?
- How and when will out-of-merit and local reliability commitments and/or dispatch be employed, and how will they be priced?
- How will transmission and generation outage scheduling be conducted?
- How will virtual bidding be accommodated?
- Will trading hubs be available?
- How will resources with unique attributes be accommodated; such as: Intermittent generation resources (e.g., wind, solar, small hydro), Energy limited resources (e.g., pumped hydro, pondage hydro), Non-dispatchable resources (e.g., PURPA Qualifying Facilities)?
- Will there be a process to handle fuel supply disruptions?
- What should be the market structure? Will it differ from the PJM market? If so, what will be different?
- What will be the requirements for resources to participate in the Energy Market? What will be the detailed bidding requirements?
- How will intermittent generation resources (wind, solar, small hydro, etc.) participate in the energy market?
- How will non-dispatchable, PURPA Qualifying Facilities be accommodated in the energy market design?

- What bilateral contract structures will be incorporated in the energy market design? Will "asset-based" contracts for either load obligations or generation resources be allowed? What, if any, accommodations will be made for existing long-term contract arrangements that were predicated on prior market designs and structures?
- Is it possible to build upon existing PJM software designs, or will a Northeast market require designing and programming new systems from the ground up?
- What system and methodology will be used for electronic dispatch for the region?
- To what degree and under what conditions will operators be able to override software solutions?
- Will resources be eligible for "uplift" payments? If so, how will eligibility be determined? How will costs be allocated?
- How will participant obligations be calculated?
- How will external ties and resources be treated?
- What bilateral contract structures will be incorporated in any market design for ancillary services? Will "asset-based" contracts for either load obligations or generation resources be allowed? What, if any, accommodations will be made for existing long-term contract arrangements that were predicated on prior market designs and structures?
- Will any market design for ancillary services include regional variations to accommodate different state retail access programs, or will individual states be expected to amend their retail regulations to conform to the RTO wholesale market design?
- Will the RTO market design allow for any sub-regional variations to accommodate geographical differences? If so, what criteria will determine is such a variation is warranted?
- Should RTO personnel be more responsive to RTO members and customers?
- What consideration should be given to inter-RTO seams issues in the development of the NE RTO?

II. Generation Adequacy (Capacity) Issues

A. Capacity Adequacy Planning Process

- How to account for/reconcile differences in the Resource Adequacy requirements of the various reliability councils (NPCC, MACC, ECAR)?
- How should the role of the NYSRC and the PJM Reliability Committee be accommodated?
- Should the installed reserve requirements of the RTO be based upon Total Installed or Unforced Capacity?
- What are the load forecasting responsibilities of the RTO, TO's and LSE's?
- What methodology will be used for the loss-of-load expectation calculations and will it be based on annual, monthly or seasonal criteria (i.e., will the loss of load expectation be the same in all months, seasons, etc.)?
- Will the methodology be applied on an RTO-wide basis or on some kind of regional/sub-regional basis (i.e., will the loss of load expectation be the same in all regions and sub-regions)?
- What are the load forecasting requirements, assumptions to be used in the determination of resource adequacy?
- What are the availability qualification requirements for supply side resources (DMNC, UCAP, other performance measurement)?

- What are the requirements for demand side participation?
- What are the requirements for special case resources (e.g., wind, diesel generators, solar)?
- What are the capacity supplier obligations (e.g., to bid, schedule, or make available Week-ahead, Day-ahead, In-day, Real-time, Reserves Markets, etc.)?
- What are the requirements for the various types of capacity resources (Nuclear / Fossil / Hydro, Base-Load / Peaking, Intermittent, Run-of River, Systems (external control areas, aggregations, municipals), Distributed Resources, Curtailable Load)?
- What are the obligations of Load Serving Entities (Annual, Seasonal, Monthly)?
- What are the outage scheduling obligations for capacity resources (e.g., Long Term (planned annual), Short-term (scheduled with "adequate" notice), Forced Outages (notification))?
- How can Retail Access programs be accommodated within the capacity requirements (e.g., Load-switching (monthly, daily, seasonal))?
- How can capacity requirements be met (e.g. – Bilateral agreements, Monthly Auctions, Seasonal Auctions, Deficiency Auctions, Long-term/Short-term)?
- What are the penalties for deficiencies or failure to supply (for both suppliers and LSE's)?
- What are the certification, Data Reporting, and Statistical Information requirements for capacity suppliers/purchasers?
- What are the deliverability requirements for external capacity suppliers?
- What are the recall requirements for external capacity suppliers?
- How are the locational installed reserve requirements determined?
- How are existing capacity contracts handled?
- How is the concept of Capacity Benefit Margin handled within the resource adequacy determination?
- What are the methodology and models to be used for such reliability analysis?
- Will the Capacity Benefit Margin ("CBM") obtainable from a specific neighboring RTO/control area of the new NE RTO be equivalent to the summation of the current CBMs (or their equivalents) from such neighboring control area previously used and relied upon by the current individual ISOs?
- How are the Emergency Operating Procedures of the various control areas modeled in the reliability analysis?
- Should a demand-side program be considered in determining capacity requirements?
- Who is responsible for establishing the rules for generation adequacy in the NERTO?
- Will the NERTO have any role in developing or implementing retail load response programs?
- How will generation adequacy be assured under a NE RTO?
- How will installed capacity requirements be established?
- Will installed capacity requirements be established on a region-wide basis or a control area basis, and will requirements be established for localities with bottled capacity?
- Will the installed capacity requirements for a control area be permitted to reflect the special reliability concerns of the control area?
- How will deliverability affect installed capacity requirements under the RTO structure?
- Will rules be developed and implemented to ensure compliance with installed capacity requirements?

- Which entities will be involved in determining the installed capacity requirements for each control area?
- What role will be played by state regulators and sub-regional reliability organizations (e.g., the NYSRC) in the establishment of installed capacity requirements?
- Should price response programs focus on both energy and capacity?
- Generation adequacy must be assured. The RTO must set the reserve requirements for all load serving entities.
- Reliability must be based on firm purchases which reserve physical generation.
- The RTO should plan for a generation adequacy standard which will maintain the loss of load probability of 1 day in 10 years for the entire region.
- The RTO should determine what local differences may exist across the region which affect the requirements needed to meet the generation adequacy standard. The RTO should identify what changes are necessary to eliminate the different requirements across the region to meet the generation adequacy standard and develop a transition plan to eliminate the differences and move to a common generation adequacy model.
- What will be the procedure for determining generation capacity requirements in areas with insufficient transmission ties, e.g., load pockets such as New York City or Long Island?
- Should intermittent resources be fairly and adequately compensated for the reliability and installed capacity benefits that they can provide in a diverse and robust generation mix for the NE RTO?
- How will generation adequacy be determined and assured?
- Will intra/inter-control area deliverability requirements be set?
- How will generation adequacy/requirements be determined/monitored? Who will have this responsibility?
- What obligations will be assigned to participants? How will they be calculated?
- What are the eligibility requirements and associated obligations of capacity resources?
- Should a single standard for long-term generation adequacy be established for the northeast RTO region? Should the standard be one-day loss of load in ten years?
- Should there be flexibility in the implementation of the reliability standard for load service entities (LSEs) so that they are not confined to a single long-term standard?
- Should LSEs be able to meet the reliability standard by maintaining adequate operating reserves (for example, as has been proposed by PJM West)?
- Should the RTO identify and publish locations where new generation is most desirable?
- Should the transmission expansion plan include not only reliability-based projects, but also transmission interconnections with other RTOs designed to maximize inter-RTO trading opportunities?
- How will the existence of separate NERC reliability councils within the northeast RTO region be reconciled? Isn't it necessary to eliminate or harmonize differing regional standards?

B. Capacity Market Structure

- Is a capacity product, separate from a reserve product, necessary for ensuring adequate capacity?
- If a capacity obligation (e.g., ICAP) is imposed, how will that obligation translate into an efficient incentive for needed capacity development?

- Should capacity resources located anywhere in the NE RTO have equal value in serving load anywhere in the NE RTO?
- Should there be a single capacity market design?
- Does a single energy market design initially make sense where markets are not equally developed throughout the Northeast?
- Should generation adequacy be assured through reserve requirements based on physical plant capacity?
- Should there be a single capacity market design until each state can insure its pro-rata share of capacity required in the region?
- Should a buyer of capacity be responsible for making sure that the seller of capacity meets adequate reserve requirements?
- Should the NE RTO set a timetable for moving to a single capacity market considering the physical ability for firm transfers between the existing regions?
- Should the reliability system be designed so that the obligation for ensuring reliability is placed equally on both sellers and buyers of capacity? Should the capacity market design assume that capacity demand is inelastic?
- Should the generation adequacy model for the NE RTO include a capacity reserve requirement? If so, what is the most equitable allocation of this requirement? Should there be a capacity deficiency penalty for not meeting the reserve requirement? Should the capacity market be structured to accommodate the needs of retail choice programs?
- How should the market be designed to assure that the capacity needs of the region are met? For example, should the existing Installed Capacity (ICAP) markets be retained or modified?
- Is a capacity market necessary? If so, should an ICAP/UCAP market be employed or should an options or other market be used to assure generation adequacy? If there is a market, how should it be structured and should there be a deliverability requirement?
- If an ICAP/UCAP market is employed, how will critical elements be identified and defined including: Time frame of the capacity market, Locational (intra and inter-control area) capacity requirements, Minimum requirements for suppliers to bid capacity into the market, Standards for determining amount of capacity loads must procure, Amount and standards for invocation of deficiency penalties, Will capacity resources be able to de-list from the capacity market to sell outside the NE RTO? Under what conditions, if any, are capacity resources subject to recall?
- What is the billing period for capacity obligations (i.e., will a market participant have to meet its capacity obligation for every hour of a day, week, month, season, year or some other time period)?
- Will capacity performance penalties be invoked, and, if so, will they be linked to their impact on Loss of Load Probability (“LOLP”)?
- How will differences in ICAP criteria between NERC, NPCC and MAAC be reconciled?
- If there is no ICAP market, will there be an obligation to provide services from generation?
- What other methods, either in place of or as a supplement to an ICAP market, could be employed to ensure sufficient capacity for the NE RTO?
- How will the planning function be structured considering both generation and transmission if there is no ICAP market and responsibility to provide services from generation facilities?

- How will the RTO ensure comparable treatment of external and internal capacity resources and facilitate capacity sales into and out of the RTO market?
- Will market participants be allowed to trade capacity credits with market participants in neighboring RTOs and, if so, what kind of deliverability requirements will be applicable and how will such capacity credit transactions impact the CBM?
- What bilateral contract structures will be incorporated in any market design? Will "asset-based" contracts for either load obligations or generation resources be allowed? What, if any, accommodations will be made for existing long-term contract arrangements that were predicated on prior market designs and structures?
- Will any market design include regional variations to accommodate different state retail access programs, or will individual states be expected to amend their retail regulations to conform to the RTO wholesale market design?
- Will the RTO market design allow for any sub-regional variations to accommodate geographical differences? If so, what criteria will determine if such a variation is warranted?
- How will the RTO explicitly and directly link capacity-related services of generators (e.g. maintenance outage coordination, dispatch obligations) to its capacity market(s) / obligation(s)?
- If there will be a capacity market to meet capacity adequacy requirements, what will be the financial obligations of parties selling capacity reserves?
- Should transmission projects be eligible to receive ICAP credit?
- If a single generation adequacy model across the RTO requires significant transmission upgrades to some areas, should the cost of upgrading the transmission system to provide for deliverability be paid for locally (rather than shared amongst the transmission owners) until the transmission capability in these areas is equivalent to that in other areas?
- Is the requirement for Load Serving Entities to acquire capacity contradictory to the concept of marginal pricing?
- Should there be a separate capacity market, or should the capacity requirements be included in the energy price?
- Should the Installed Capacity (ICAP) deficiency charge for non-compliance with this requirement be based on the cost of replacement peaking generation or on some other value, given that the NE RTO will have a capacity reserve requirement that is calculated consistently for all entities?
- Should a single capacity market be established throughout the northeast region?
- Is it appropriate to design a long-term capacity market (one year or more) to reduce swings in the market cycle?
- Should the reservation of large amounts of CBM as part of the reliability standard be eliminated? Doesn't it contribute to the lack of liquidity in the current PJM markets since external generation is unable to secure firm transportation to compete in the PJM market during times of high prices?
- Is it feasible for the northeast RTO to move to a single control area, or to reduce the number of control areas?
- Should there be a single independent market monitoring unit (MMU) for the entire northeast RTO region – an entity that is permitted access to all data available to the RTO (but not part of the RTO governance structure other than for funding and administrative purposes), and that reports directly to the FERC?
- Is it necessary and appropriate to establish price caps for the capacity market until the MMU is satisfied that there is sufficient liquidity in the markets?

C. General Comments

- Is power supply reliability paramount, and therefore must it be maintained?
- Should uniform generation standards be created to preserve reliability?
- Should uniform rules be created for providing adequate capacity and assessing penalties for noncompliance?
- Will the NERTO have a single set of rules for generation adequacy, including capacity requirements and penalties?
- Although the NERTO order prohibits a discussion of ICAP, MAPSA recommends that both the business plan and the ALJ's report discuss the need for the scheduling of a proceeding to address this issue as soon as possible, if not concurrent with the Commission's review of the business plan and report. The Commission has recently addressed this issue in PJM, adopting an interim approach and requiring that this issue be resolved on or before the summer 2002 peak period.
- Should the business plan acknowledge that the Commission's reinstatement of the New England ICAP requirement was remanded last month by the U.S. Court of Appeals for the First Circuit in Central Maine Power Co. v. FERC, 252 F.3d 34?

APPENDIX A-3

Stakeholder-identified Sub-issues Pertaining to Operations

I. Generation Scheduling

- Will the standard for operations continue to be security-constrained economic dispatch?
- Will the RTO have the ability to order redispatch of generating units, in the most economically efficient way, to address reliability problems?
- Is it feasible to perform single day-ahead financially binding unit commitment of all generation within the RTO (given the number of variables that must be recognized by any commitment process that address generator parameters, transmission constraints and locational requirements, and interchange with the neighboring RTOs)?
- If overall unit commitment is shown to be infeasible (in the short and/or long run) in the RTO, will individual Control Area commitment be recognized as the financially binding day-ahead commitment for a single market?
- What should be generator rights/obligations with respect to scheduled outages?
- Should there be direct RTO - individual generator communication for unit desired operating schedule?
- Should all communications with generators be through the RTO, ISO's or TO's?
- Do all generators have to bid into the system or can some be self-scheduled? (Is self scheduling allowable?)
- Is all load supplied through the market, subject to the market-clearing price?
- Is self-scheduled load allowable?
- How will locational costs of reserves be allocated?
- How will ancillary services be co-optimized with energy?
- How will demand response resource scheduling and demand response resource dispatch be dealt with?
- How will the scheduling and dispatch of demand resources be performed at each of the ISOs and what will be the differences between them?
- Do operating processes penalize alternative resources for their intermittency?
- How can we best strike a balance between (a) a generator's right to schedule its own maintenance, and (b) the RTO's need for efficiently scheduled maintenance, to avoid the situation where so much maintenance is scheduled into a particular period that it significantly affects prices?

II. Transaction Scheduling

- Are external transactions treated consistently with internal generation, and do they receive bid production cost guarantees?
- Do all transactions (including external) bid into the market?
- How frequently can external transactions be scheduled or modified?

III. Generation Dispatch

- In order to optimize system efficiency, will there be a unit commitment analysis that considers the entire Northeast RTO, and its neighbors, and commits generation throughout the Northeast on a lowest cost reliable basis?

- Will generators receive an energy scheduled (basepoint) or price signal?
- Will generators be required to supply bids or follow price signals?
- How are costs for supplemental resource requirements for local reliability allocated?
- Will the RTO develop one security constrained economic dispatch for generation?
- Will the RTO have the authority to coordinate maintenance outages?
- How will the RTO reimburse generators and transmission owners for increased costs incurred to meet RTO needs if the RTO changes maintenance outages at the expense of the owners?
- How will out-of-merit dispatch, including its cost, be handled?

IV. Transmission Operations

(Control of Transmission Facilities)

- Will the RTO be responsible for the reliability and operations of the bulk power and network responsible facilities?
- Should the RTO have operational control of all network transmission facilities necessary to provide transmission service across the northeast region?
- Will there be a demarcation between transmission under the control of the NE RTO and systems that are the responsibility of TOs?
- Will all interconnections with New England and New York be integrated and operated according to a single set of RTO rules?
- Will the Highgate Converter and HVDC Phase I/II facilities which connect the Hydro-Quebec system to the New England region be operated under a single Northeast RTO tariff, with all available Highgate and HVDC Phase I/II capacity posted on a single OASIS?
- Will the RTOs authority be extended to include control of and the development of operating procedures for jurisdictional transmission facilities that are not presently controlled by an ISO and are covered by a separate OATT?
- Will the RTO continue to maintain a focus on more localized system concerns as it expands its geographical breadth and scope of operations?
- Will TOs retain the right to physically operate their systems as is currently done under PJM?
- Will the determination of what facilities are placed under the control of the RTO recognize existing state jurisdiction over station service and stranded costs?
- What will be the RTO's authority and requirements for coordinating, prioritizing, changing, and approving maintenance and outages for transmission and for generation?
- Will there be incentives for coordination of transmission outages, including merchant transmission, to reduce impact on the markets?
- Will the RTO reimburse generators and TOs for increased costs incurred to meet RTO needs if the RTO changes maintenance outages?
- What will be the back-up dispatch plans?
- Disaster Recovery and interim operating procedures?

(Parallel Flows)

- Will Transmission Loading Relief procedures and other scheduling mechanisms be assessed and implemented across the whole RTO region rather than by sub-region?
- What will be the operational impacts of parallel flows?

- What will be the process for handling parallel flows?
- How will existing ISO to ISO agreements, such as the Ramapo Phase Shifter agreement, be handled?

V. Control Area Operations

(Reliability)

- Will the tariff and market design ensure system reliability while protecting against exercise of market power?
- Will the RTO form one control area or keep separate control areas?
- How will the RTO maintain focus on more localized system concerns as it expands its geographical breadth and scope of operations?
- Will the RTO establish detailed plans to transition from the 3 ISO market systems into a single RTO market system (including relationship with the IMO) and maintain reliability and a viable wholesale market?
- Will short-term reliability continue to be the first principle under which the RTO operates?
- How will the RTO insure short-term reliability?
- How will the RTO redispatch and reimburse generation for short-term reliability needs?
- Should the RTO have more than one security coordinator that can address regional reliability needs?
- Will the existing reliability levels in all three ISOs and Canada be maintained under a new RTO structure?
- Will the NE RTO direct the operation of all generation and transmission facilities?
- Will RTO reliability rules address the special reliability concerns of individual control areas and localities within control areas?
- Will existing local reliability requirements of certain areas such as New York City be maintained under a new RTO structure?
- What will be the authorities and procedures to respond to system emergencies?
- How will reliability of the generation and delivery system be maintained under a Northeast RTO?
- Will reliability standards be developed by an independent body through an open and inclusive process?
- Will there be mandatory reliability rules addressing both operations and planning under a Northeast RTO?
- What will be the process for developing the new RTO reliability rules?
- Which entities will be involved in developing the RTO reliability rules?
- What will be the process for modifying the RTO reliability rules?
- How will compliance with RTO reliability rules be monitored and how will non-compliance be addressed?
- Which entities will be involved in monitoring compliance with the RTO reliability rules?
- How would reserve requirements for each Control Area under a RTO be determined?
- Would transmission constraints between regions determine the amount of ten minute reserves, which could be counted toward reserve requirements in other control areas?
- How will hydro resources be treated in reserve accounting?

(Operating Standards)

- Will there be a single set of operating standards developed so that inconsistencies across the control areas are eliminated?
- Will FERC insist on one set of operating standards, rules, and procedures for the Northeast RTO, based on best practices?

(Control Area Hierarchy)

- What will be the RTO and operation control center hierarchy?
- What will serve as the Alternate Control Center?
- Will there be a common RTO Control Center?
- Will the RTO be a single Control Area with a single Security Coordinator?
- Will the schedules between (existing) CA's be dynamic?
- How often will schedules be modified (hourly, ¼ hour, every dispatch cycle)
- Are providers of reserve services eligible for lost opportunity costs?
- How are reserves priced and costs allocated? (Regional or locational)
- To the extent possible, will existing operating facilities and infrastructures be incorporated in the design of RTO operations?
- Will the NE RTO be composed of and direct four separate control areas or transition to a single control area in the end state? If the existing control centers remain will they be reduced in size?
- What are the benefits of implementing and transitioning into a central market operations facility separate from existing ISOs?
- What communications will occur between surviving control centers and the market participants, regulators, and other control areas outside the Northeast RTO?
- Will there be back up provisions to address critical failures of one or more control centers?

(Role of Other Entities Concerning Reliability)

- What role will be played by state regulators and sub-regional reliability organizations (e.g., the New York State Reliability Council) in developing, maintaining, and monitoring compliance with the RTO reliability rules?
- How will existing New York State Reliability Council reliability rules currently in place in the New York Control Area ("NYCA") be incorporated under a Northeast RTO?
- Under a Northeast RTO, will the New York State Reliability Council continue to be responsible for the promulgation and monitoring of reliability rules that address the special reliability needs of the NYCA and localities within the NYCA?
- How will reliability requirement that impacts dispatch in the markets be standardized?
- Will a common foundation of reliability criteria be developed that would permit Canadian entities to interact seamlessly with NE RTO?
- Will there be an international regional council organization to accomplish the development, compliance assessment and enforcement of reliability criteria that includes NPCC?
- Should FERC direct the RTO to work with NERC toward one Northeast Reliability council contiguous with the Northeast RTO comprising all functions in the existing reliability-related organizations in the existing ISO structures?

- What will be the relationship between NPCC, MAAC, and ECAR, and should NPCC and MAAC merge?
- What will be the characteristics and functions necessary for the Reliability Organization or Organizations that establish the reliability criteria for the Northeast RTO?

(Other Issues)

- What types of communications are to be considered confidential and when would they become not confidential?
- What information will be required to be made available to all participants (posted) and which information must be updated on a regular basis?
- Can a single security coordinator adequately handle the needs of all of the control areas in the RTO?
- Will the RTO develop one security constrained economic dispatch for generation?

APPENDIX A-4

Stakeholder-identified Sub-issues Pertaining to Technology Assessment

- Will there be an RTO system separate from any of those of the existing ISOs with its own technology (computer systems, software, staff) to run the integrated RTO market?
- Will "new" RTO software be separate from existing ISO software, or will the current software from each of the ISOs be modified as the basis of any upgrades to accommodate RTO formation?
- Will there be a technology evaluation of what is the "best practice" for implementing the Northeast RTO once the market Best Practices are identified and agreed to?
- What functions and associated software will be active in each control center (RTO, ISO, TO) for operations, including requirements for NERC tagging?
- What computer systems and technology (including the use of open systems procurement and design) are required by the RTO to perform its functions?
- Will the PJM software be used as the basis of any upgrades to accommodate RTO formation?
- Will the RTO implement compatible technology and software across the regions in order to minimize implementation costs?
- Should efforts be made to "debug" the system prior to implementation of the RTO, for example, in order to ensure accurate and timely billing?
- Will there be an interim operations arrangement to start up RTO operations before completion of software systems?
- Before the three ISOs are combined, should there be any limitation to the development and/or installation of new software?
- Will there be a single integrated RTO OASIS or three OASIS nodes in NE RTO?
- Should the RTO develop one overall operating system (e.g. OASIS, tagging) for the northeast region?
- What is the role and scope of OASIS (Phase II for the NE RTO)?
- Will the computer network and interactive communications design support RTO requirements for market operations and hierarchy?
- What will be the plan for a full test of all systems, successfully conducted market trials, operating manuals, and RTO staff and market participant training prior to startup?
- What will be the network interfaces, date transfer requirements and protocols required by the RTO?
- What market software systems will be active in each center?
- Will the software system be able to easily deal with changing needs that develop during operation?
- Is there a need to retain an independent expert or experts to analyze the adequacy of existing ISO and other available technology?
- Will the RTO:
    - Define network interfaces, data transfer requirements and protocols that may require modifications in existing facilities (ISOs, TOs)?
    - Make use of code management tools to ensure quality control of software development?
    - Define the coordination between planning and operation software functions?
    - Define the authorities and procedures to respond to system emergencies?

APPENDIX A-5

Stakeholder-identified Sub-issues Pertaining to Transmission Tariff

I. Tariff Design

(Single NE RTO Tariff)

- Will there be a single NE RTO administered tariff for the entire NE RTO region, regardless of size and location, to be implemented solely by the RTO?
- Should the RTO move towards a single, RTO wide Open Access Transmission Tariff (OATT), using best practices from each RTO region? If so, what transition period will be needed before complete integration of a single OATT and RTO wide transmission rates?
- Will all interconnections with New England and New York be integrated and operated according to a single set of RTO rules?
- What transition period will be needed before complete integration of a single OATT and RTO wide transmission rates?
- Should the RTO ultimately try to move – within a five-year transition period – to a single system transmission rate?
- Should license plate rates be used during the transition period?
- How will jurisdictional transmission facilities that are not presently controlled by an ISO and are covered by a separate OATT be integrated?
- Will the single OATT be implemented in accordance with the following principles:
  - What transmission rates will be used for all facilities operated by the RTO?
  - What rates will be used for transmission facilities not operated by the RTO but traditionally used to provide transmission service to transmission dependent utilities?
  - Elimination of pancaked rates across the NE RTO while mitigating revenue losses for transmission owners consistent with the concept of revenue neutrality?
  - Elimination of pancaked ancillary services and losses?
  - Elimination or mitigation of cost-shifting?
  - Account for and address regional differences associated with various voltage connections?
  - Develop and implement a single OASIS for the RTO where all transmission transactions are listed and scheduling is done across the region?
  - Allow for coordination with states regarding reliability and account for state stranded cost determinations?
  - Allow for coordination with states regarding retail rate price caps?
  - Allocate local reliability costs?
  - Provide an agreement for the handling of stranded investment?
  - Allow for meaningful participation and advise by market participants, public and private stakeholders and transmission owners in an advisory capacity?
- Will the RTO tariff address tax-exempt bond issues and set tariff and revenue requirements to avoid imperiling tax-exempt financing?
- Will the RTO tariff incorporate ultimate market design, including ancillary services and transmission expansion?

- Should the pro-forma OATT provide for development of transmission products that increase throughput, efficiency, and reliability?
- Will merchant transmission be handled in the tariff, and if so how?
- What are the voltage levels and facilities covered under the RTO tariff?
- Should business practices/tariffs for external ties be handled under the regional tariff in order to address seams issues and to provide consistent/uniform treatment of external transactions?
- Will RTO rate design be coordinated with retail access regimes administered by TOs/distribution service providers?
- Will the costs of the Highgate Converter and the HVDC Phase I/II facilities which connect the Hydro-Quebec system to the New England region be rolled in to the single Northeast RTO transmission costs?

(Load Response Resources)

- Will the tariff be designed to assure that intermittent, distributed and customer load response resources are treated fairly?
- Will the RTO's OATT have specific provisions that enable customer load response resources to participate fully in the energy, capacity and ancillary services markets in the Northeast?

(Other Issues)

- Will there be RTO to RTO market and operations agreements?
- Will any and all rate design and revenue requirement issues address who is the ultimate consumer of the Tariff?
- Will the federal and state law rights of non FERC-jurisdictional TOs be preserved, including right to establish their own revenue requirements to be collected through the RTO Tariff?
- During the transition period, will existing rules that require generation units to purchase local transmission service, in addition to pool transmission service, be revised to eliminate discriminatory impact?
- Should the RTO allow or encourage the development of Independent Transmission Companies and for profit transmission companies?
- Will the RTO Transmission Tariff be designed to prevent double billing, for example double billing of service provided through other tariffs, agreements or contracts?
- Do transmission tariff provisions facilitate the integration of renewable and alternative energy sources consistent with the National Energy Policy? (Comment references Report of the National Energy Policy Development Group, p6-14 stating: "for renewable and alternative energy to play a greater role in meeting our energy demands, these sources of generation must be able to integrate into our existing distribution system. The tools that form the necessary interface between distributed energy systems and the grid need to be less expensive, faster, more reliable, and more compact.")
- How will Transmission Scheduling Rights ("TSR") purchased in open seasons for merchant transmission projects be reflected in the tariff?
- How will compensation for ancillary services and other proven system benefits such as capacity upgrades on existing AC lines resulting from (HVDC) merchant systems, if any, be determined?

- What actions will the Northeast RTO implement to maximize available capacity on: (1) the HVDC Phase I/II facilities; (2) the lines extending from the Niagara Mohawk Power Corporation Dennison Substation to the Canadian-US boundary (also called CD-11 and CD-22); and (3) the 765 kV line which connects Hydro-Quebec to the New York Power Authority (also called the 70/40 line) in order to relieve constraints?
- Should the RTO assume responsibility for all grandfathered transmission agreements where service is provided, in whole or in part, by facilities operated by the RTO? Where grandfathered transmission service is provided over non-RTO facilities, should responsibility for service remain with the Transmission Owners? Should grandfathered transmission agreements be phased out over time (for example, a five-year period)?
- Will the tariff treat generation equally in terms of service, interconnections, and ancillary services (e.g., imbalances)?
- Will the tariff allow for the development of new transmission products that will increase throughput, efficiency and reliability?

II. Network Transmission Service

III. Firm Point-to-Point Transmission Service

- Should scheduling of external transactions in day-ahead market and real-time market be accomplished solely on the basis of economics and timestamp (as a tie breaker)?
- Should curtailment of external transactions be accomplished utilizing transmission priority?
- How will transmission capacity be allocated, as a physical product, a financial product, or a combination of the two?
- How should transmission service for native load be allocated, separately, or as with all capacity, by auction, or otherwise?
- Can a single allocation method for transmission capacity across control areas be consistent with intra control area capacity systems that may be individually designed?
- What are the proper durations of transmission service?
- What does firm transmission service mean (physical vs. financial definition)?
- Must transmission service be reserved or can transactions simply be scheduled?
- Should congestion rights come with the purchase of transmission service or be offered through an auction?
- How will inter control area transactions be allocated transmission service?
- How will the costs caused by the abandonment of equipment and reduction in employees covered by the replacement of the three ISOs with one RTO be treated?
- Will the costs of the Highgate Converter and the HVDC Phase I/II facilities, which connect the Hydro-Quebec system to the New England region, be rolled in to the single Northeast RTO transmission costs?
- Has it been demonstrated that the NEPOOL pilot program for innovative transmission maintenance provides real benefits to consumers? If so, what are they?
- Will expanded use of programs like the NEPOOL pilot program for innovative transmission maintenance have an adverse impact on ongoing transmission system maintenance practices?
- How will grandfathering of existing contracts be handled?
- How will out-of-merit dispatch be treated for rate and other purposes?

IV. Non-Firm Point-to-Point Transmission Service

- Should "Willing to Pay congestion" (WPC) and "not willing to pay congestion" (NPC) mechanisms be accomplished through market provisions/interface or through transmission tariff/mechanisms?
- Should non-firm transmission service be limited based on reservations carrying NPC designations?
- How will the issue of non-jurisdictional transmission assets be handled for purposes of scheduling?
- How is ATC calculated?

V. Transmission for Retail Access

- Will the RTO tariff design accommodate the different retail access programs through out Northeast?
- To what degree will the RTO Tariff provisions related to retail access be aligned or synchronized with the underlying state retail access rules and procedures?
- Will RTO Tariff accommodate retail customers taking transmission service directly versus providing transmission service to 'Load Serving Entities'?
- What credit worthiness criteria will be utilized under the RTO Tariff for LSEs that are seeking to obtain service under the RTO tariff?
- How will defaults by LSEs be handled under the RTO Tariff?
- There now exist PLRs who are not the Electric Distribution Companies. How will PJM rules regarding creditworthiness, default and termination be applied to such an entity?
- Should Load Serving Entities have a predetermined Capacity Obligation based on the historic usage of the customers that they serve (as is the case in PJM and New York) or an obligation that is determined after the fact based on their customers' prospective usage (as is the case in New England)?
- Should the RTO establish consistent demand response programs and, if so, should such programs qualify and be counted as capacity and/or reserves?

VI. Tariff Rates

(Revenue Requirement and Return)

- Will rates provide an opportunity for all TOs to recover revenue requirements, including a fair and reasonable return on investment?
- How will the transmission owner revenue requirement be allocated?
- How will excess RTO (above TO revenue requirements) revenues be distributed (due to load growth, incentives, etc.)?
- How will the issue of nonjurisdictional transmission assets be handled for purposes of revenue recovery?
- How are transmission owners compensated?
- How are NYPA revenue requirements recovered?
- Who sends the bill(s) to the users of transmission service?
- Should TOs submit revised revenue requirements to the RTO?
- Do TO's have 205 rights of their revenue requirements and submit revenue requirements to FERC for review and approval?

- Should revenue requirement calculations include any new transmission projects the TOs undertake at the RTO's direction?
- Will rates in excess of a fair rate of return for RTOs be allowed? Alternatively, What constitutes a fair rate of return for RTOs?
- Will FERC's regulation of RTOs rely solely on traditional cost of service on a rate of return methods or employ innovative rate designs/revenue requirement recovery methods?
- Will any transmission cost recovery mechanism be designed to assure recovery of costs for existing network transmission system facilities as well as facilities that will be directed to be constructed by the RTO?
- Will there be a consensus position developed on cost-recovery for economic transmission enhancements that will be supported by state commissions and that will fit their policies on cost recovery from retail consumers (under state prudency review of federal jurisdictional rates)?
- Will the Commission firmly establish that ITCs not be allowed to revalue investment in facilities above net book value on the existing utility's books nor be entitled to recover acquisition premiums through rate-related or tariff mechanisms? (Alternatively: Will ITCs be allowed to revalue investment in facilities above net book value on the existing utility's books or be entitled to recover acquisition premiums through rate-related or tariff mechanisms?) How will revenue requirement cost recovery be effected for those transmission systems where the application of a "license plate" access fee is not feasible?
- Will the methodology for obtaining cost recovery for economic transmission enhancements under the RTO Tariff be supported by state regulatory commissions? Will said methodology be compatible with their policies regarding what costs can be recovered from retail consumers (under state prudency review)?

(Transmission Rate Design)

- On what basis will transmission and ancillary service costs and losses be based? The zone where the load is physically located, fully regional, or some combination of the two?
- Is the transmission revenue recovered on a license plate or postage stamp basis and can rate design mitigate cost-shifting issues?
- During the transition to a broader Northeast RTO, will the RTO continue existing zonal rates ("license plate" rates) in effect for an appropriate transitional period? (New England does not have a purely 'zonal rate' design as described by NY and PJM)
- Should a regional adjustment charge mechanism be put in place to ensure revenue neutrality of the license plate approach?
- Will the (license plate) rates in effect currently for each region transition first to a single rate for each existing ISO before there is a movement to the single RTO rate for the entire Northeast?
- If rates transition to a single RTO rate, will the revenue neutrality of transmission owners be maintained, and should a regional adjustment charge mechanism or other method be used to maintain revenue neutrality? How long should revenue neutrality be guaranteed?
- Should the adjustment charge mechanism be reviewed by the RTO annually during the transition period, and rate changes submitted to FERC as necessary to maintain

revenue neutrality? Should transmission owners submit revised revenue requirements to the RTO as part of this process?

- Will the tariff be designed to ensure that implementation of transition rate mechanisms to guarantee revenue neutrality to TOs will require the TO to demonstrate that without these mechanisms the TO's revenue would be less than the TO's costs plus a reasonable return on its assets?
- What is the cost impact on PJM, New England and New York ratepayers of any possible transition from license plate rates to postage stamp rates for a Northeast RTO?
- Should the RTOs develop transition rates that reimburse TOs for the loss of revenues due to the elimination of pancaked rates?
- Will the rates provide for non-discriminatory service to each specific customer within the RTO?
- Should the RTO develop zonal rates for both transmission and ancillary services that allow TOs to recover the zonal cost of doing business?
- Should the rates for existing transmission facilities continued to be based on traditional cost-of service?
- How should revenues received from non-network customers be treated in determining revenue requirements and rates?
- Will there be a credit for the facilities, including interconnects, installed by customers or at customers' expense?
- How will transmission tariff be integrated into retail bundled and unbundled rates?
- How will the RTO implement the joint rate methodology agreed to by PJM in the Alliance/MidWest ISO Agreement?
- How will the RTO integrate PJM West (ECAR requirements) and Allegheny transition costs into the RTO rate structure? (A broader statement of this issue, such as "How will the RTO integrate an ITC's rate structure, like PJM West, into the RTO rate structure?" would be more appropriate.)
- Should transmission customers subsidize poor location decisions by merchant plants?
- Should the RTO move, after a transition period, to a single system transmission rate? If license plate rates are used during the transition period, with a regional adjustment charge mechanism put in place to ensure revenue neutrality, should the adjustment charge mechanism be reviewed by the RTO annually during the transition period, with rate changes submitted to the FERC as necessary to maintain revenue neutrality? Should transmission owners submit revised revenue requirements to the RTO as part of this process? Should revenue requirement calculations include any new transmission projects the Transmission Owners undertake at the RTO's direction?

(§ 205 and § 206 Rights)

- Will there be an ITC and, if so, will it be part of a hybrid RTO or will it be a TO that participates in the Northeast RTO?
- Who will have the right to make § 205 filings regarding the rates, terms, and conditions (other than with respect to individual TOs' revenue requirements) for the Northeast RTO?
- What stakeholder advisory process will be followed before a § 205 filing is made and what obligation will there be, if any, for the § 205 filing to respond to concerns raised by the stakeholders?

- When an ITC or Transmission Owner is subject to an order to build over its objection, will it be authorized to file a limited § 205 filing to ensure its recovery of the costs associated with that project?
- Will the RTO assume all liability for § 206 issues?
- If there is an ITC with its own tariff, Will transmission service providers be able to design and administer the ITC tariff with exclusive authority to seek revisions under § 205 to the rates, terms and conditions for transmission service over the facilities they control?
- Ensure that the RTO must consult and coordinate with Transmission Owners (including non-FERC jurisdictional TOs) before making Section 205 filings and instituting changes in rate design that may affect the recovery of transmission owner revenues?
- Ensure that the RTO must consult and coordinate with Transmission Owners (including non-FERC jurisdictional TOs) to ensure that RTO rate design is coordinated to properly implement retail access regimes administered by transmission owners/distribution service providers?

(ISO Costs and Expenses)

- How will expenses associated with creating the RTO and modifying existing ISOs be handled, including expenses related to software, hardware, energy management systems, personnel, etc.?
- What are the costs associated with the integration of processes, manuals, systems and software necessary for the implementation of a Single NE RTO?
- How will the three Northeast ISOs capture and track the costs associated with the implementing a single NE RTO Tariff?
- What, if any, cost-benefit analysis will be performed with respect to the degree of integration that will be undertaken?
- How will costs be allocated over administration of energy and ancillary service markets?
- Will transition charges be spread over all market participants in the NE RTO and will there be an effort to minimize transition charges?

(Incentives)

- Will the RTO cooperate as necessary to facilitate FERC acceptance of incentive rate mechanisms that will accommodate varied forms of transmission ownership (including multiple ITCs and existing ownership structures)?
- Will the RTO agreements recognize the option of the RTO, including any component ITC, to file for incentive rates?
- Will there be any time in the post-mediation framework for consideration of incentive rate proposal in the initial rate filing?
- Will incentive rates be a condition of membership in or a reward for joining the Northeast RTO?
- Will incentive rates be revenue neutral in both the transition and after the RTO is operational?
- Will there be incentive rate mechanisms to stimulate construction of transmission facilities and to make transmission a financially viable alternative to generation for mitigating congestion?

- Will the RTO structures and/or practices embody appropriate incentives designed to achieve high performance in key RTO performance areas, such as tariff administration, OASIS administration, congestion management, and cost effective decision-making?
- Will there be incentives and penalties related to transmission expansion, upgrades and maintenance?
- To the degree incentive rates are made available, will they be offered on a non-discriminatory basis to any would be constructor, be solely applied to practices beyond those actions which are necessary under Prudent Utility Practices, and entitle all builders of transmission to a reasonable return on their investment?
- Should the RTO develop incentive rates for both generators and transmission owners?
- Will there be incentive rate mechanisms for generators and demand side solutions to congestion?
- Should incentives be provided for demand side solutions to congestion?
- Should incentive rates be structured so as to be commensurate with the size or complexity of the congestion addressed?
- What innovations in tariff design can ensure that intermittent resources, such as certain renewables, have open access to markets rather than being penalized for their differences from traditional resources?
- Should the RTO allow short-term rates that can be used to resolve short-term congestion or reliability problems?
- Will incentives for efficient investment decisions be provided in the RTO Tariff?
- Will the agreement require that any innovative rate design be developed by the RTO and submitted by the RTO under § 205?
- Will incentive rate design recognize that non-FERC jurisdictional TOs are not permitted to charge incentive rates?
- Will incentive rates provide for penalties as well as rewards?
- Will the baseline be set so that mere compliance with good utility practice incurs neither penalty nor reward?

(FTR Revenues)

- How will long-term FTRs (TCCs) be handled?
- If allocated financially, does the FTR (TCC) auction have to occur simultaneously for the entire region or will it be done separately for sub-regions or zones?
- Will FTRs (TCCs) be auctioned simultaneously for different periods?
- How should revenues received from FTR auctions be treated?
- Will revenues collected pursuant to congestion management pricing be viewed as a source of financial incentives when construction relieves transmission congestion via beneficial transmission, generation and demand side investment?
- What mechanism will be used to honor existing FTR (TCCs) and other hedges?

(Interconnection)

- Will the current PJM pricing mechanism for the pricing of new facilities to interconnect to generation, which uses a "but for" test when a portion of the facilities provides system-wide benefits (allocating associated costs among all system users), continue under the new RTO?

- Should merchant generators directly bear all "but for" system upgrade costs without receiving transmission rate credits for system upgrades?
- Should FERC revisit the application of "and pricing" to system upgrades associated with generator interconnections to avoid subsidy of congestion costs by transmission customers?
- Will the RTO determine interconnections costs in a nondiscriminatory manner?
- Who is responsible for bearing the costs of generation redispatch required when transmission lines are taken out of service in order to interconnect to new generation? (This issue is currently pending before the Commission in Boston Edison Co., Docket No. ER01-890-000, and was left open in ISO NE, 91 FERC ¶ 61,311 (2000)).

VII. Reactive Supply and Voltage Control from Generation Sources Service

- What is the appropriate basis for reactive load payments? Should they be based on a revenue requirement, or should they be based on the value provided (to distinguish between circumstances in which reactive support provided by generators is extremely needed, and other circumstances in which reactive support provides less benefit)?
- Should generators be penalized if they cannot provide their reactive support?
- How should reactive payments be determined for new capacity that is added to a zone?

VIII. Energy Imbalance Service

- Will there be imbalance penalties?
- How should the revenues from imbalance penalties be treated?
- Should the RTO use a two-settlement system?
- Should the RTO permit or employ virtual transactions?
- Will all generators be subject to imbalance penalties?
- Should imbalance service be an obligation of generators and loads and should it be available for inter-CA transactions?
- Should imbalance penalties be structure to provide meaningful incentives to correct performance?

IX. Black Start Service

- Will there be an RTO-wide black start/restoration plan?
- Will Black start market/compensation be bid or cost based?
- How will local black start requirements be addressed/compensated?

X. Losses

- How will losses be priced?
- How will the true cost of losses be allocated?

XI. Excepted Transactions

- Will any existing, Pre-Order No. 888 service contracts be abrogated in order to create the NE RTO?
- Will existing agreements, including the NEPOOL settlement, be honored, unless it is mutually agreed to incorporate them into the corresponding RTO structure?

- How will grandfathered transmission contracts be handled?
- Should the RTO assume responsibility for all grandfathered transmission agreements where service is provided in whole or in part by facilities operated by the RTO?
- Should responsibility for service remain with TOs where grandfathered transmission service is provided over non-RTO facilities?
- Should grandfathered transmission agreements be phased out over a certain time (five-year) period?

APPENDIX A-6

Stakeholder-identified Sub-issues Pertaining to Transmission Planning

I. Transmission Planning

(General)

- Will the RTO utilize PJM's transmission planning process, subject to "best practices," as the platform for the creation of a centralized planning process for all transmission facilities under the RTO's control? To the extent planning requirements appear in existing accepted RTO agreements, should they be recognized as guides to addressing sub-issues respecting transmission planning and construction? What modifications are necessary to the proposed intra-RTO transmission planning process to address inter-RTO transmission development?
- Should the RTO's transmission planning process serve as a central planning function and as a safety net for when the market does not address reliability needs? How will the transmission planning process and the resource interconnection process be integrated? How does transmission get built in the future? Under who's control will new facilities be operated by be included in the transmission planning?
- How are existing grand-fathered agreements recognized in the planning process? Should the transmission planning and expansion processes encourage more efficient use of existing transmission facilities and rights of way? If yes, how?
- Is there a voltage level or some other dividing line at which point planning would be more efficiently conducted at a local level? What portion of the transmission system is the RTO responsible for planning? What portion is the local distribution company of TO responsible for?
- How will the RTO planning and transmission expansion process ensure that the rights and obligations of the parties under the Federal Power Act will be honored?
- How can transmission interconnection capacity be maximized to its physical design potential?
- What should the interconnection procedures be with respect to the maintenance of existing feasible transmission capacity?
- What level of detail should be represented in: 1) transmission planning and modeling (e.g. lower voltage transmission lines) and 2) operations?
- What is the process for integration of Phases I and II of the HVDC facilities and the Highgate converter, as pool transmission facilities under the RTO Tariff, as required by the FERC?

(Assessment and Study Process)

- Will there be a single coordinated regional transmission plan?
- Should it be updated every year by the RTO?
- Should the single expansion plan for the entire region be supplied as a single document to the stakeholders?
- At what point should the transmission plan be revised to reflect the effect of market projects (load response, new generation, merchant transmission) that have been announced? Licensed? Commenced construction? How far out in time should a transmission plan look to evaluate the viability and robustness of a proposed

transmission configuration? Who may request the RTOs to perform transmission studies?

- What will be the basis for determining the need for transmission projects and how are these standards established? Do these standards include economic as well as reliability criteria? Are these standards publicly available? Will they consider needs/costs of transmission expansion and impact on transmission rates with an eye to benefits to end user customers of any increased costs? Must those criteria ensure protection of local generation capacity from new transmission facilities to energy deficient regions? Should transmission planning limit generation siting?
- Will all projects be justifiable and if so on what basis (cost/benefit)? How will alternative solutions be considered and evaluated?
- How will the RTO assure its plans are consistent with reliability rules? What criteria and process will be used to identify and select from transmission and non-transmission solutions to apparent needs?
- Should adjoining regions exchange proposed expansion plans to ensure no adverse consequences to one another?
- How are the assumptions for these analyses determined?
- What is the RTO approval process?
- How is data confidentiality maintained?
- How should the current and future load requirements of transmission dependent utilities be taken into account in the development of RTO transmission and generation interconnections and expansion plans? How do we address various load forecasting methodologies? Ability to use special protection schemes (SPS) to overcome constraints. Differences in analysis tools (i.e., short circuit and breaker capability analyses – classical analysis using PSS/E versus more detailed analysis using ASPEN One-Liner; assumptions of time decrement factors for breaker ratings). Traditional joint planning-operations analyses; probabilistic planning; resource planning; generation interconnection; reliability versus economic transmission expansion; inter-regional studies. Will there be any local load priorities for transmission, new, old, or merchant? Should more sophisticated load profiles be developed for small customers so that customers can be credited for load reducing and energy efficiency investments?
- Should assumptions of generator dispatch and/or bid prices be included in transmission system impact studies used for transmission planning studies? How should the transmission plan deal with the uncertainty associated with market-based facilities (new or existing)?
- If ability to share reserves among three control areas changes, how will the RTO ensure adequate transmission export/import capability? How will load diversity among three areas be recognized to possibly reduce reserve margins? How will the RTO address loop flows – potential for it and mitigation? What Consistent planning terminology and processes will the RTO employ (e.g., ATC)?
- How do we consider various facility rating criteria (i.e., different criteria used for development of line ratings and development of long term emergency & short term emergency ratings)? Should the RTO have overall responsibility for assigning ratings to power system components based on input from facility owners and accepted industry standards?
- How are environmental considerations generally incorporated into the planning process? How will environmental considerations be factored into the process prior to the RTO determining a needed transmission project?

- How is access allowed for "green" power and renewables that may not conform to traditional central planning constraints (this includes eliminating barriers in traditional planning processes that devalue intermittent resources)?
- Will the RTO planning process be required to consider all reasonable options for meeting transmission enhancements needs, including non-transmission resources and strategies that take advantage of locational benefits? Will the RTO adopt/approve options based on the lowest life-cycle costs to the system?

(Reliability Needs)

- How will the RTO transmission planning process ensure that the existing reliability standards are not degraded? The RTO planning process needs to ensure that local reliability requirements are addressed, including the unique reliability needs of New York City. How should the transmission planning and expansion process best accommodate the maintenance and asset replacement plans for the existing transmission system? Should the transmission planning and expansion process accommodate special transmission adequacy or reliability requirements of particular customers or regions?
- During the RTO transition process, should there be an evaluation of the pre-existing level of reliability of the transmission systems in the existing ISO regions, to ensure that there is no cost-shifting between regions related to the construction of facilities deemed necessary to reach a baseline level of reliability?
- How are long-term reliability considerations, such as the capability of gas pipeline systems, considered in expansion planning? Should expansion planning be done on a least-cost basis, consistent with reliability requirements, with cost recovery based on cost causation principles?
- How do transmission planning studies interface with the reliability councils and studies required to establish reliability requirements for the Northeast regions? How do we achieve consistency of planning criteria within the RTO since PJM uses MAAC criteria and NY & NE use NPCC criteria?

(Identifying Options: Expansions and Other Alternatives)

- Will there be a different process for identifying congestion-mitigation opportunities and economic upgrades than for identifying solutions to load growth/local reliability needs? Will load growth/local system reliability be placed on a fast track? How should the RTO's transmission planning process encourage market-motivated operating and investment actions for preventing and relieving congestion, such as transmission expansion, new generation, and demand side programs? How are market-based projects (generation, transmission, and load management) accounted for in the transmission needs assessment? How should the planning process and RTO ultimate control over coordination and final approval apply to both reliability required transmission facilities and any economic enhancements which the process identifies? How does the planning process allow alternative resources to compete against planned transmission upgrades (e.g. localized generation – including distributed generation that can eliminate the need for the planned transmission upgrade and at lower cost than the upgrade)? How do we ensure that all market-based solutions are accounted for in a fair and unbiased manner? To what extent will the owner of or physical right holder in new transmission facilities receive financial rights associated with the increased transmission capacity? How will the quantity of rights be determined?

- Will there be any differentiation in the plan between transmission projects for which the sponsoring party is immediately willing to construct versus projects that are more conceptual and intended to be for the future?

(Process Transparency and Stakeholder Involvement)

- How do stakeholders verify that the data used by the RTO for transmission planning is correct? What process will be used to allow stakeholders, including state regulators and representatives of the public, to provide input (including consideration of alternatives to transmission expansion such as load response programs, distributed generation, central generating stations, demand side management, etc), and to review the transmission planning analysis and ensure that all stakeholders are treated equally? What appeal process will be available if a stakeholder believes the transmission plan does not adequately address planning criteria? How should stakeholder inputs be provided to the planning process? What role do stakeholders have in the transmission needs assessment? Can stakeholders appeal the RTO assessment and if so under what conditions and what is the process? How is public accountability established for transmission planning failures?
- Does the RTO staff prepare the plan from scratch, based on input from transmission owners and others or does the RTO staff assemble a plan based on information submitted by transmission owners? How will alternatives to a transmission solution, i.e. generation, load abatement, etc., be presented? What importance will be ascribed to the transmission plan in the RTO's generation interconnection process? What will be the respective roles of the RTO staff and ITCs in the formulation of the transmission plan? Under what circumstances should the RTO contract with transmission owners to assist in the planning process?
- How should the RTO's process provide for uniformity and transparency of transmission planning standards used by each TO in the RTO?

(Role of the States (Siting))

- What will be the relationship between the RTO determination of need and the state transmission siting process? Can the RTO process do anything to resolve FERC authority over transmission facilities? Will a single RTO for the northeast necessitate FERC jurisdiction over transmission siting? Is this issue affected by differences such as intra vs. interstate, merchant, utility, RTO owned? How should state-level regulatory and legal considerations be reflected in the development of expansion plans? How should the RTO work with the states to establish standards which facilitate the siting and construction of interstate transmission projects? Must consider realities of lead time needed to order and construct/install equipment.
- How does the RTO coordinate with state and federal environmental authorities on transmission planning?
- Must state regulatory commissions approve those portions of the plan proposing construction of facilities within their jurisdictions? Resolve jurisdictional issues between federal and state interconnection and siting requirements. How do we address and incorporate the siting requirements, which are subject to state jurisdiction and state process?

(Liability and Role of the RTO/TO)

- How will the rights and obligations between the RTO and the transmission owner associated with transmission expansion and interconnections on a transmission owner's system be established? Who is liable for any damages that occur to existing transmission and distribution facilities that result from the expansion?
- What agreement (by TOs, the RTO, or others) will cover the subject of transmission planning and construction? Will the agreement spell out who will collect data, whose employees will conduct studies, the required circulation and input of information on initial studies, and the process for final resolution of all items for a coordinated regional plan? Should there be a specific defined reservation of the role of any potential independent transmission companies (ITCs) in this process?
- How will we integrate transmission and distribution planning under the RTO? What is the appropriate allocation of planning and engineering responsibilities between the RTO and the distribution companies? How should responsibilities be divided between the RTO and each transmission owner so that transmission plans do not adversely affect operations, reliability and facilities beyond the RTO's monitoring and expertise?
- How can it be ensured that the RTO has ability to keep TOs on schedule with required transmission enhancements?

(Obligation to Build)

- Under what circumstances will transmission owners have an obligation to build? If there is no obligation to build, how will the RTO ensure that transmission is built? Does the obligation to expand facilities apply to all needs identified in the plan, or only to reliability needs? Does any party or parties have an obligation to build transmission facilities included in the regional plan? If yes, do they also have the right to build the same facilities?
- If the RTO plan includes any economic enhancements, should TOs have the right to decline? Are market participants given the opportunity to build first? If parties are allowed to bid to build projects included in the plan and no entity submits a bid to meet a need identified in the plan, how will that need be met? Does RTO have authority to require transmission upgrades to be performed? Will the RTO have the ability to order construction or improvement of transmission facilities where necessary for reliability?
- To the extent TOs decline economic driven enhancements, should third party construction that does not violate state franchise law or other legal or regulatory requirements be authorized? Should a cost recovery mechanism be defined which should allow for inclusion of incentives and/or non-traditional ratemaking devices?
- What assurances must TOs be granted of recovery of any expenditures (including any study and/or build requirements) they are required to make by the RTO? Should there be a guaranteed cost recovery mechanism associated with the obligation to build?
- Will transmission owners have a duty to serve and if so to whom is the duty owed? What criteria and processes, including who will build and what will be the cost recovery mechanisms, will the RTO establish for the inclusion of economic expansion transmission projects in the Northeast regional transmission expansion planning process?

- Once a project has been selected/approved, what steps should the RTO take to support that project before various governmental entities?

(RFPs and Competitive Construction)

- How will solutions to meet RTO-identified transmission needs be procured? Who is eligible to construct and own projects that are needed to meet RTO-identified transmission needs? How is eligibility determined?
- If parties are allowed to bid to build projects included in the plan, how will the winning bidder receive the bid price? Would a bid process cover construction only, or would ownership be involved as well? Is the winning bidder responsible for obtaining all required permits, or is some other entity responsible for doing so prior to the bid process? If parties are allowed to bid to build projects included in the plan and no entity submits a bid to meet a need identified in the plan, how will that need be met? If parties are allowed to bid to build projects included in the plan, how will the winning bidder receive the bid price?
- How do we address use and value of existing right-of-ways and franchise areas? If parties are allowed to bid to build projects, who will be responsible for obtaining right-of-way environmental and other state and local permits? How long a period will they have to obtain necessary permits and rights? What financial or other performance guarantees will they be required to provide?
- If the RTO is responsible for the RFP process including negotiating terms and conditions (such as indemnification) to construct new transmission facilities that would be owned by existing TOs, can the RTO force the TO to accept the contract as negotiated with a third party?
- Is there a viable way to auction ownership of transmission expansions in the context of cost-based rates, and if so under what conditions? How will RFP winners be held to negotiated terms and conditions?

(Merchant Transmission)

- What defines merchant transmission?
- Should merchant transmission projects be differentiated as between AC and DC?
- Under what circumstances will FERC allow merchant transmission?
- Who has access to merchant transmission, at what price and under what terms?
- How does merchant transmission fit into a regional transmission grid?
- How will merchant transmission projects be integrated into RTO operations?
- Should merchant transmission owners and facilities be accorded all the same rights and responsibilities (and/or be treated the same) as other new and existing transmission owners and facilities under RTO arrangements?
- Should merchant transmission and other new transmission owners have the same obligation as existing transmission owners to comply with Orders Nos. 888 and 889?
- Should the planning process allow for RTO control of economic-driven enhancements of merchant facilities?
- How could transmission planning responsibilities (needs assessment, identification of transmission options for meeting the needs, verification that the transmission solutions meet the need) be allocated within an RTO that has one or more independent transmission companies?
- What information process and financial initiatives should independent transmission companies implement to provide the proper incentives for reliability and competitive

markets while guarding against any bias, real or perceived, that ITCs or individual transmission owners may over-build transmission?

- How will merchant facilities' scheduling rights be incorporated into RTO financial rights?
- What planning and expansion procedures should merchant transmission projects be subject to for interconnection?
- Are merchant projects proposed by non-transmission owners considered the same as those by transmission owners? How does the right of eminent domain factor in?
- Do merchant project developers need to demonstrate that there are no market power concerns associated with their ownership and control of transmission where they have a generation or commercial interest?
- How should the RTO transmission plan resolve differences between proposed TO and merchant transmission solutions for the same situation?
- How should merchant transmission projects be accommodated in the RTO regional transmission tariff?
- How will merchant transmission projects be compensated, and how will the costs of such projects be recovered?
- Should merchant transmission projects have the same interconnection rights as merchant generation?
- Should the RTO establish criteria and processes for the development of merchant transmission projects, including reliability, comparability and the requirements in Neptune, Docket ER01-2099-000, that merchant projects which determine their own timing, at-risk status, size and rates, must be prepared to bear 100 percent of the risks and cost responsibilities for their projects?
- Should the rates for merchant transmission facilities incorporated within the RTO not be cross-subsidized? Should merchant transmission projects conform to all applicable reliability and design criteria, and bear 100% of the risks and costs responsibilities of their own projects?
- Should any merchant transmission construction comply with all federal, state, and local requirements for construction, safety, etc.?
- Should the transmission planning process facilitate the participation of merchant transmission developers where appropriate on an economic and reliability basis?

II. Generation Interconnection

(Rights and Obligations)

- To the extent the RTO has ultimate decisional authority respecting interconnections, how should the appropriate authorizing documents incorporate criteria to be followed by the RTO? Should these criteria include safeguards to protect TO assets (based on owner criteria) and system reliability?
- To what extent will rights or expectations under existing rules (e.g., NEPOOL Tariff Section 49, Schedules 14, 15) be preserved? Will the principle of "revenue neutrality" be applied to the expectations and incentives under which existing projects were committed to and built?
- How will the RTO incorporate input from transmission owners, all market participants, state commissions and state public advocates in the interconnection process?

- Under what circumstances and to what extent will the RTO be liable to or required to indemnify the owner(s) of existing transmission facilities or to customers connected to those facilities, if it permits unsafe or unreliable interconnection?
- Who shall be eligible to own interconnection facilities and what is the point of demarcation between these facilities and transmission facilities?
- How will the RTO Interconnection process ensure that the rights and obligations of the parties under the Federal Power Act will be honored?
- How will jurisdictional issues between federal and state interconnection and siting requirements be resolved.
- Should the entity needing interconnection be allowed to install the interconnection?

(Agreements)

- What form of agreements will be offered to interconnecting resources? Will these be standard forms? Should these form agreements be appended to the RTO tariff?
- How is the transmission owner protected or indemnified from liability for actions of the interconnecting resource?
- If there are pro-forma agreements, should they allow for the opportunity for individual negotiations? Should generators and RTO have the ability to negotiate financial incentives related to time milestones?

(Standards)

- Will there be a single technical interconnection standard for the northeast? Do the interconnection standards apply only to generation or to delivery (load) interconnections as well? Will such standards apply only to proposed interconnections with the transmission system under the RTO's operational control or transmission tariff, or will they also apply to proposed interconnections with distribution systems?
- How will the RTO incorporate/respect the varied interconnection requirements and system protection protocols currently employed in the northeast such that the interconnection of new facilities does not compromise the safety and reliability of existing facilities? How will interconnection rules consider the specific operational and reliability requirements of local transmission systems? How would the RTO assure that local reliability will not be degraded as a result of new interconnections?
- Should the RTO adopt only a minimum interconnection standard or offer a choice between a minimum interconnection and an "enhanced" standard that addresses deliverability?
- How will enhancements to the transmission system, such as FACTS equipment, new electronics, etc. be handled?
- Who will assure that relay settings, tap settings, routine switching and tagging and other such operational requirements included in properly crafted interconnection agreements are properly carried out or are in compliance?

(Applications, Procedures, Studies and Administration)

- How will interconnection requests be made to the RTO? Are new or revised load serving entities considered as an Interconnection issue? Are new or revised transmission facilities considered as an Interconnection issue?

- When will the RTO post interconnection requests on the OASIS? At what point should information regarding a prospective interconnection become public domain?
- What constitutes a completed application? What information must be submitted up front as opposed to later? What are minimum technical info/requirements?
- What are the application and study fees?
- What studies will be required to be performed? What will each study contain or seek to achieve? How will study costs be established? What assumptions will be used in those studies, or how will the assumptions be determined? What opportunities will be available for stakeholders to review and comment?
- How will the interconnection study process work in relation to queue position? How will the queue process (e.g., queue ordering, project modification restrictions, treatment of online dates in reverse order from queue order, posting of queue information) be managed?
- If a project queue is created, how will projects that wish to move ahead of projects ahead in the queue be accommodated (construction sequencing)? Should there be an impact of queue position on interconnection studies and cost allocation?
- What time frames will be imposed for completing relevant studies?
- How will studies for intermittent resources be performed?
- Should the RTO have an obligation to offer terms and conditions for interconnection within a defined period from receipt of an acceptable application?
- How should the responsibilities for acting on generation and transmission interconnection applications be allocated within an RTO (e.g. among TOs or ITCs)?
- Does size matter? Will the RTO develop an expedited interconnection procedure for small generators (e.g. PJM's procedures for units less than 10 MW) and customer sited generation? Will voltage level matter?
- Can the interconnection process be shortened and streamlined for new generation in congested areas?
- What would be the dispute resolution arrangements?
- Who will handle the day-to-day interaction with customers associated with administering interconnection agreements?
- Could the problems resulting from different queues and criteria regarding the impact of the RTO interconnection standards impact on neighboring RTOs and Canadian provinces be resolved through a study that assigns cost responsibility?
- Should generators connecting to the distribution system be covered under the RTO policies and procedures, or is this a local Distribution company issue?

(Construction, Planning and Coordination)

- Will interconnection planning rank new facilities by their environmental impact? How will coordination with state and federal environmental authorities on issues such as the treatment of small generators be handled?
- Is there a need to do generator planning in conjunction with transmission planning?
- How will construction and maintenance be prioritized and coordinated by the RTO?
- Will the RTO bid-out the construction work necessary to interconnect new resources? What role will the resource have in this process?
- How can the effective capacity of existing interconnections with the RTO's neighboring control areas be utilized to avoid being reduced by the interconnection of new generators?

(Transition)

- How will existing interconnection agreements and related contracts be addressed? For example will existing interconnection-related FTRs/FCRs and transmission revenue credits be carried forward, and if so how?
- During the transition to a single RTO, how will the RTO assure that implementation of existing generation interconnection projects are not delayed as a result of the standardization of interconnection procedures? How will the RTO coordinate the interconnection requests in the queues of the various existing entities and integrate them into a single RTO queue?
- During the transition to a single RTO, how will ongoing generation interconnection projects that did not benefit from the RTO centralized planning function have the opportunity to benefit from integrated system impact analyses? Should such integration be at the resource's option?
- Should the existing planning processes of the PJM provisional RTO and the NY and New England ISOs be coordinated?

III. Cost Allocation and Property Rights

(Transmission Planning and Construction)

- Who will pay the costs of performing the transmission planning studies?
- How does the RTO ensure that entities that build transmission facilities are able to adequately recover their investments – particularly if ordered to do so?
- What is the required approval process for a TO to initiate a transmission project that is to be included in cost-based rates?
- How do we address wholesale and retail cost recovery issues?
- Can there be a single transmission facility/project that has a portion of its rating recovered in cost-based rates and a portion of its rating recovered through merchant-based rates?
- What criteria should determine which economic enhancements can qualify for at risk entrepreneurial type revenue recovery (e.g., Neptune precedent)?
- How do we make sure all new projects that impact transmission expansion requirements, either past, present, or future projects, pay their fair share of costs?
- Will the "class year" concept be applicable?
- Does locational marginal price have to be revised to encourage transmission being built that completely relieves a congested interface? Is there any mechanism to compensate alternatives to transmission upgrades that provide the same or similar capacity/reliability as the transmission upgrade would provide?
- Should a portion of congestion charges collected be used to upgrade transmission facilities to remove transmission congestion?
- Do the rights of a transmission expander expire after a certain period of time? If so, who is responsible for the operation and maintenance of merchant transmission after the rights expire?
- Who pays for transmission expansion, both regional asset expansions and local transmission asset expansions? How shall the costs for system reinforcements be allocated? Will cost allocation differ for reliability versus economic transmission projects? Will transmission planning of new facilities' financial impact on existing facilities be addressed? Who bears the costs of fixing the system if reliability is degraded as a result of a transmission expansion?

- What objective and non-discriminatory criteria will be used to allocate the costs of transmission expansion, and will those criteria be uniform throughout the transmission system subject to the control of the RTO? How will the costs of transmission upgrades be allocated? How will costs be allocated for projects built pursuant to the transmission needs procurement process? Incentives for transmission expansion (allocation of financial or physical transmission rights)
- Could any entity needing a transmission upgrade or an expansion be allowed to do so at its own cost? Should the costs of facilities that are an integral part of the transmission network (e.g., transmission to: a) get bottled generation out of sub-areas; b) supply a load-constrained area; c) reduce congestion costs; d) improve market competitiveness; and, e) address other reliability constraints) be socialized to all transmission customers? Should facilities that are specifically attributed to the integration of a new generating unit be paid for by the new generator?
- If it is determined that the RTO can bind the TO, how will the RTO assure (e.g. via up-front payments, security bond, or other appropriate vehicle) that the TO can recover any costs the TO incurs as a result of RTO decisions?

(Interconnection-related Costs and Property Rights)

- Should interconnecting resources and the RTO have the ability to negotiate financial incentives related to time milestones and interconnection completion?
- Who will be responsible for the ongoing maintenance of and associated operation and maintenance costs for both direct interconnection facilities and transmission system upgrades that would not have been developed but for the interconnection of new transmission and generation?
- Who pays for congestion or lost opportunity costs that result from construction of a generator interconnection? Does the RTO have the authority to schedule generator interconnection work to minimize congestion cost? Should transmission owners or operators be penalized for increasing congestion and/or rewarded for reducing congestion?
- How should the RTO deal with state rate caps issues if costs are not allocated to generators?
- What security will be required to guarantee payment of upgrade-related generator financial obligations and/or what minimum level of generator creditworthiness will be required?
- Where the RTO constructs the interconnection, must the cost be considered contribution in aid of construction (CIAC)?
- How will the incremental benefits accruing to the system as a result of the interconnection be measured and the credit allocated?
- What interconnection costs are subject to allocation? E.g.: construction, carrying charges, O&M, redispatch, lost opportunity costs? How will transmission carrying-charge costs be allocated between generation and load?
- How will services provided by the resource (e.g., reduction in line losses, VARs etc.) be linked to opportunities to be compensated for that service?
- How does a party challenge a determination of FTRs?
- What should be the procedures for determination of relative impact (e.g. thermal, voltage, stability impact)?
- What protections will be put in place to prohibit uneconomic bypass/stranded investment associated with merchant transmission interconnections?
- Who pays to restore local reliability if RTO decisions do adversely impact it?

- Who determines the O&M charges to be paid by interconnecting generators and/or merchant transmission providers? Who is responsible if actual O&M charges for these facilities exceed the levels set by the process?
- Will the RTO accommodate resources that choose to privately contract with transmission O&M firms (such as the local utility) rather than receiving this service from the RTO? Will the RTO foster competition in this service?
- How will concerns about pricing of interconnection services where market power is an issue be addressed?
- How will eligibility for treatment as system upgrades be determined?

APPENDIX A-7

Stakeholder-identified Sub-issues Pertaining to Interregional Coordination

- Will the NE RTO participate in an interconnection-wide process to address and resolve commercia lly significant and other inter-RTO seams issues such as the following:
  - ensure that generation/transmission expansion in each area are included in planning processes coordinated to ensure system reliability?
  - avoid stranded costs?
  - promote efficiency in the process?
  - address rate pancaking?
- How homogeneous will the NERTO be?
- How will the external seams issues be addressed?
- How will the NERTO coordinate with Alliance, MISO, Grid South, and the Canadian companies?
- How will the RTO work with adjacent systems to make sure that generation/transmission expansions in each area are included in the adjacent areas' planning process to ensure system reliability?
- Would the Canadian companies wish to join the NERTO?
- To what extent would they participate? (IMO has the option of NERTO or Alliance)
- On a technical level, inter-RTO seams issues will still need to be addressed. How will the following issues be handled:
  - inter-RTO congestion management?
  - transaction scheduling and checkout?
  - ICAP outside the RTO?
- Will the NE RTO continue to negotiate in good faith to resolve seams issues with other regions, specifically the Alliance and Midwest ISO to develop a joint rate methodology for transactions involving all of the three RTOs and associated revenue distribution?
- Will the seams negotiation required by FERC between PJM and the Alliance and GridSouth be integrated into the process of developing the northeast RTO?
- When should interregional coordination (seams) issues be resolved and in put in place?