Regional Networked Market Concept
For Implementation of a Single Regional Energy Market Including Allegheny Power, New England, New York and PJM

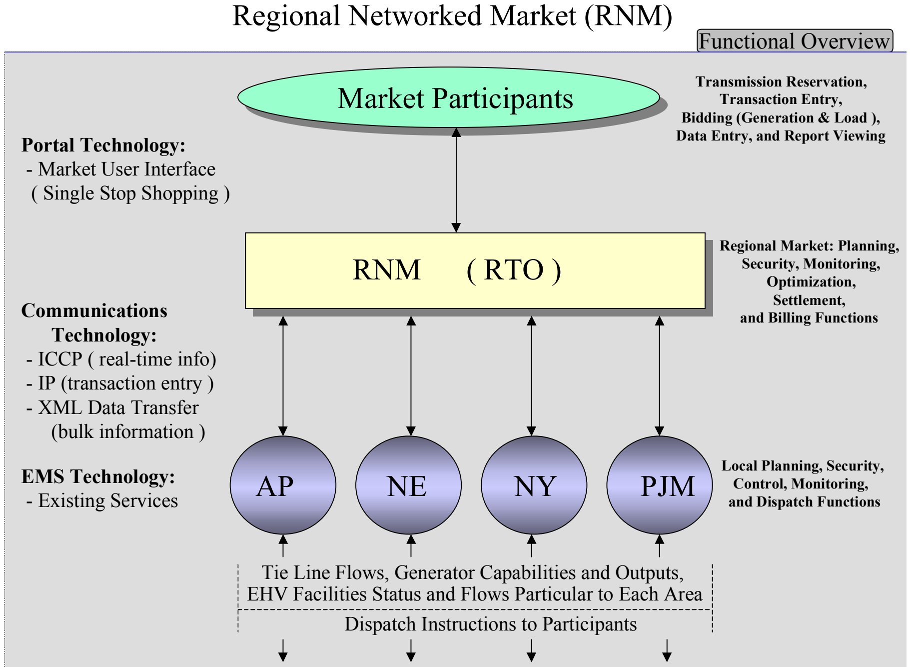
A large and growing coalition of stakeholders in the RTO mediation process have expressed a strong desire to expedite the implementation of a single regional RTO while maintaining the safe and reliable operation of the regional power grid. The coalition has indicated a desire to implement a single Regional Energy Market that satisfies all local and regional reliability requirements as quickly as possible based on the PJM platform and including any best practices[1] that can be incorporated without substantially delaying the implementation process. The stakeholders have favored an approach that results in quick implementation of the baseline energy market with incremental implementation of additional best practices after initial implementation. In response to these stakeholder requests, PJM has developed an implementation plan based on a Regional Networked Market (RNM) concept.

Overview

The Regional Networked Market (RNM) is structured to take full advantage of existing ISO systems and technology in order to implement the regional energy market in the quickest and most cost-effective manner. The design concept is based upon the premise that the four existing Control Areas (APS, New England, New York and PJM) will continue to exist under the Regional Market and will continue to provide basic control area functions. This implementation approach utilizes the existing ISO Energy Management Systems (EMS) for local control area functions and as data servers to the Regional Market Software. The design will provide a single regional market with a common market data interface across the entire region while maintaining existing technical and engineering data interfaces that are in place today to support regional reliability. An overview of the Regional Networked Market (RNM) is provided in Figure 1.

Figure 1

Regional Networked Market (RNM)



[1] The best practices that are envisioned to be included in the implementation are outlined in appendix A.

The scope and functionality of the Regional Networked Market is summarized below. The design will provide a baseline set of functionality on a fast implementation timeline and will provide the capability to expand and enhance the functions in the future.

The baseline Regional Networked Market will consist of the following functions:

- Single Day-ahead Energy Market
- Single Real-time Energy Market
- Single Financial Transmission Rights Product/Market
- Single OASIS System
- Single Transaction Management System
- Single Market Information System
- Single Settlements[2] and Billing System
- Four Regulation Markets (with common rules)
- Four separate Operating Reserve Market Areas

Optional enhancements to the baseline Regional Networked Market can include:

- Four Spinning Markets (with common rules)
- Separate settlement rules and potential markets for Operating Reserves
- Additional Ancillary Services Markets (i.e. Blackstart, Voltage Control, etc.)

Day-ahead Energy Market

The Day-ahead Market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day based on the concept of Locational Marginal Pricing. The Day-ahead Market is cleared using Security-constrained unit commitment and dispatch software to satisfy energy demand requirements[3], reserve requirements[4] and control area load forecasts[5] by minimizing the offer-based production cost. The results of the Day-ahead Market clearing include hourly LMP values, hourly demand and supply quantities, hourly control area tie schedules and phase angle regulator schedules.

The transmission network model utilized in the day-ahead analysis is consistent with the transmission network models that exist in each local control center's EMS system. The transmission network model topology will include scheduled transmission outages that are reported by each local control center and which are coordinated by the RTO. The day-ahead analysis will include all transmission contingencies that are modeled in the control area EMS systems.

[2] Includes bilateral financial transaction management system (i.e. PJM eSchedules)
[3] Including price-responsive demand and virtual demand bids and virtual supply offers
[4] Including locational reserve requirements and any local reliability requirements specified by the local control area
[5] The software will be capable of scheduling generation to satisfy the load forecast requirements either as part of the Day-ahead Market clearing or as part of a separate reliability-based unit commitment analysis to minimize the startup and cost to schedule the additional generation at minimum output. This requirement can be satisfied using the same unit commitment algorithm with modified data input processes.

Real-time Energy Market

The Real-time energy market is based on least-cost, security-constrained[6] economic dispatch across all four control areas. The dispatch is executed every five minutes and results in a set of control area tie schedules and unit-specific dispatch instructions. Each individual control center will also have the capability to redispatch for constraints internal to their system using their existing tools to the extent the constraints are not modeled in the regional dispatch. Each control area will provide all such constraint information and resulting generation dispatch instructions back to the regional market for use in the Regional dispatch function. All such generation redispatch for constraint control will be used to set LMP values. Generation that is operated for local transmission constraints (that are not eligible to set LMP) will be directed by the local control centers[7] and modeled in the dispatch and pricing as fixed generation and will be guaranteed at least their offer price.

The transmission network model utilized in the real-time market software will be the same model that is used in the Day-ahead software with the topology dynamically modified[8] to include current real-time operating conditions and topology changes. These inputs will be fed from each control center's state estimator or telemetry infrastructure that resides on their EMS systems. The regional market model can be driven by either state estimator technology or by a dynamically adjusted powerflow model.[9]

Operations

Each control area will operate under and report to the RTO. The RTO has the ultimate responsibility for reliability and security of the transmission system. Initially the local control centers could be responsible for maintaining regulation and operating reserves in their area as well as redispatch for local constraints as described above. Local control areas will be responsible for monitoring and control for transmission security in coordination with the regional authority. Consolidation of control area and security functions and implementation of "best practices" could be accomplished on an incremental approach after gaining appropriate experience and completing appropriate cost benefit analysis.

Financial Transmission Rights

The Financial Transmission Rights (FTRs) product will be the same as the existing TCC/FTR products that exist in today's markets. The transmission network model utilized in the FTR analysis and auctions will be the same model that is in the day-ahead analysis with the topology updated as appropriate for the study period. The technical software to be utilized in the analysis will be capable of performing single or multi-period auctions and/or allocation analysis as required by the RTO business rules.

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[6] The constraints modeled in the regional dispatch will initially be at least the major transmission interfaces in each control area and will include all constraints with inter-control area effects. The delineation of constraint control will evolve over time with the potential end state resulting in the RTO managing all constraints.

[7] Such operation will be coordinated with the RTO.

[8] The telemetered system conditions and topology updates will be automatically transferred from the control center EMS systems to the market systems through the high-speed data links.

[9] This decision will be driven by the results of a feasibility and cost-benefit analysis.

Market Participant Interfaces

The Regional Networked Market will provide a set of integrated Market User Interfaces to allow participants to perform seamless data entry and view market information. The OASIS system and the Energy Transaction Management system will be integrated and will support NERC tagging formats and protocols. The market will include a Market Information System to allow Market Participants to manage their positions and to view market results in a near real-time environment.

RTO Functions[10]

The RTO functions related to the energy markets are:

- Operation of the Day-ahead Energy Market
- External Transaction Scheduling
- Operation of the Real-time Energy Market
- Interregional Coordination
- Coordination of transmission and generation outage schedules
- Transmission Security Analysis
- Transmitting real-time dispatch instructions and other relevant information (i.e. interregional transfers) to local control centers
- Settlements and Billing
- Managing the Market Information Systems

An overview of the interactions of the major functions is shown in Figure 2

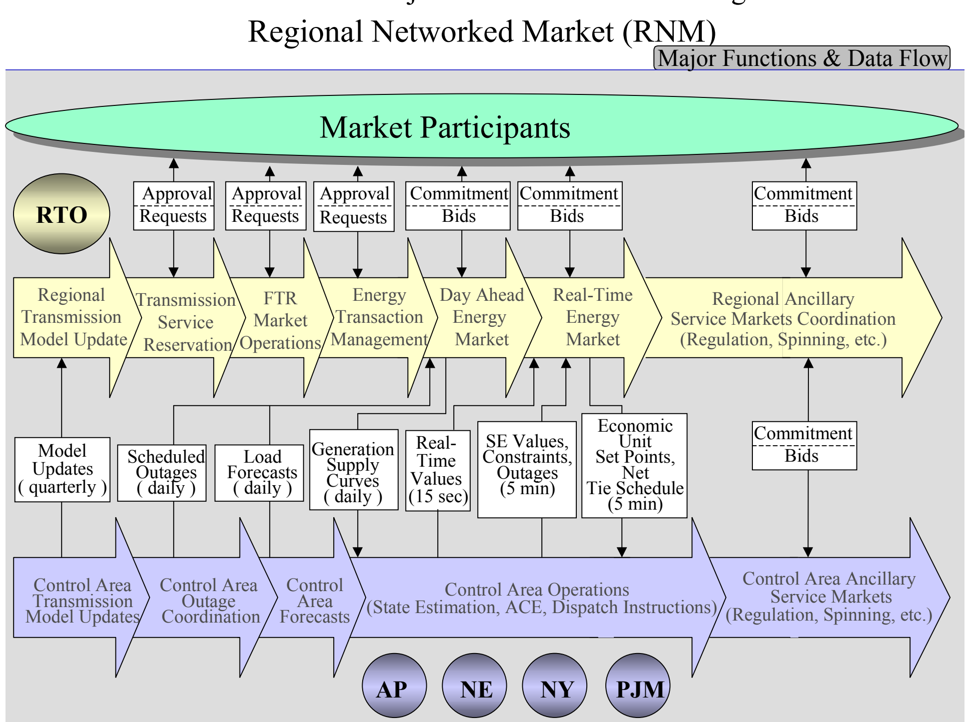


Figure 2

[10] The RTO functions listed here are only those functions directly related to the operation of the energy markets, other RTO functions (i.e. regional transmission planning, etc.) are not listed. Therefore this is not and exhaustive list of the RTO functions.

Local Control Center Functions

- Local Security Analysis
- Coordination of Transmission Security with RTO
- Coordination of Transmission outages and switching with RTO and Transmission Owners
- Transmitting real-time dispatch instructions to generators
- Real-time Regulation Market
- Monitor real-time ACE
- Managing EMS system and telemetry communication links
- Coordinate data model updates with RTO and Market Participants

Regional Networked Market (RNM)

The Regional Networked Market (RNM) concept will take advantage of existing EMS technology and telecommunications infrastructure. The existing EMS telemetry system will continue to provide the real-time information to and from Transmission Owners and Generation Owners into the local control centers. The utilization of these systems will minimize the impact of the RTO implementation on the technical infrastructure of existing ISO member companies. The implementation effort will be focused on developing data exchange protocols and systems between the local control centers and the RTO systems. The data flow model for this concept is shown in Figure 3.

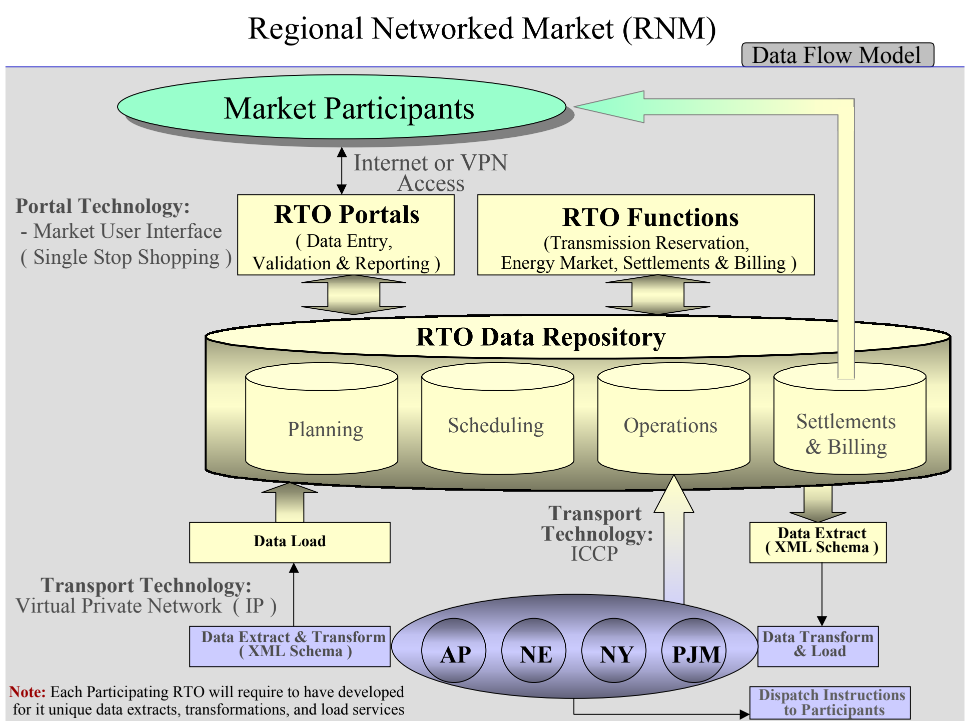


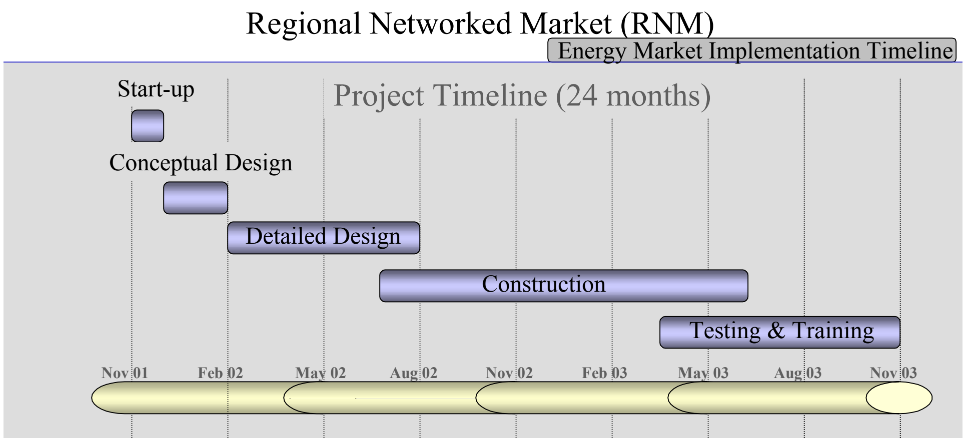
Figure 3

This design will also take advantage of lessons learned from existing designs for Market User Interfaces and Market Information systems. Under this approach, the Market Participant interfaces from each existing ISO will be examined from both a technology and Market Participant perspective. The resulting design will include the best practices of these existing interfaces and will support existing data exchange formats wherever possible. The basic design philosophy will be to utilize existing individual technical and engineering data interfaces while providing a common market and system data interface to facilitate region-wide energy trading.

Project Management Timeline

The Regional Networked Market (RNM) concept is not a new or untested design philosophy. PJM has utilized this technique in the design to expand the PJM Energy Market with the implementation of the PJM West control area. This project is well along in the implementation process and is scheduled to commence operation in January, 2002. The project estimates provided below are based on PJM's experience in implementing the PJM West concept. Preliminary scalability testing on the PJM technical software components has indicated that the existing technical software designs can perform adequately for the size requirements anticipated in the Regional Market.

Because this design concept heavily leverages existing functionality and proven software technologies, a two-year implementation time period at a cost of approximately $70 million is estimated. A high-level implementation time line with associated expenditures for this effort is shown in Figure 4.



Hardware			5.0	5.0	5.0			
Software			5.0	5.0	5.0			
Telecom			5.0	5.0				
Proj. Manage.	.6	.6	.6	.6	.6	.6	.6	.6
Design	.6	1.2	1.2					
Develop/Test			4.0	6.0	6.0	6.0	1.2	.6
Total	**1.2**	**1.8**	**20.8**	**21.6**	**16.6**	**6.6**	**1.8**	**1.2**

Estimated Expenditures ($71.6 million)

Figure 4

Appendix A

ACCOMMODATION OF ISO-NOMINATED BEST PRACTICES BY THE REGIONAL NETWORKED MARKET MODEL

As discussed in the accompanying paper, the Regional Networked Market (RNM) design concept is based upon the premise that the four existing control areas (APS, New England, New York and PJM) will continue to exist under the regional market and will continue to provide basic control area functions. This approach uses the existing ISO and local energy management systems for local control area functions and as data servers to the regional market software. PJM staff developed this approach as a means of addressing the desires of market participants to expedite the implementation of a single RTO and regional energy market while maintaining the safe and reliable operation of the regional power grid, including satisfaction of all local reliability requirements.

The RNM concept is intended to accommodate initially all identified best practices that can be addressed without substantially delaying the implementation process. Other best practices could be incorporated after initial market start-up. As generally discussed in the accompanying paper, RNM is intended at the outset to provide a high degree of functionality and address the reliability concerns that have been raised. This general conclusion can be tested by reviewing the best practices identified by the other independent system operators in the region and considering the degree to which RNM would incorporate or address those suggested best practices.

The New York ISO ("NYISO") and ISO-New England ("ISO-NE") have identified various differences between their market, tariff, and operational practices and those of the PJM platform. ISO-NE and NYISO have nominated a total of forty of their practices in these three areas as best practices, to be considered as supplements or changes to the PJM platform.[11]

As discussed below, RNM would accommodate nearly all of these nominated best practices at RTO start-up. Of the 40 suggested best practices, RNM would address 35 at the outset.[12] Some would be accommodated at the regional level as RTO functions, while others would be accommodated at the local level as local control-center functions, inasmuch as these NYISO or ISO-NE best practices would continue to be performed by the local control centers for those areas. The New York local reliability issues were specifically contemplated when the RNM concept was developed and will be included. Other best practices suggested by the ISOs (for example, use of marginal losses) can be accommodated on the RTO implementation date if the suggested practice is adopted within three months of the Commission's order in this proceeding.[13]

Of the five remaining ISO-nominated best practices, four (for example, certain additional ancillary service markets) could be incorporated sometime after start-up. The timing of their implementation would depend largely on the timing of stakeholder agreement or other determination of the terms of those services. The final suggested best practice is incompatible with RNM and would not be adopted. In addition,

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[11] There appears to be some duplication among the nominated practices, so the total number may be less than forty. NYISO and ISO-NE have also nominated best practices in other areas, such as transmission planning. Implementation of RNM should have no effect on whether the suggested best practices in those areas are adopted at RTO start-up.

[12] Two of the best practices that are accommodated at start-up include certain aspects that are incompatible with RNM and would not be adopted.

[13] Three of the suggested best practices that are addressed at the outset are mooted by RNM.

The remainder of this Attachment briefly explains how each of the NYISO and ISO-NE nominated best practices (taken verbatim from the business plan) is addressed by RNM, using the categories described above.

A. Best Practices that Will Be or Can Be Accommodated Through RNM at Market Start-up.

1. Practices Handled by the RTO Under the RNM Concept.

- New York performs a reliability based unit commitment to meet forecast load and export requirements, that includes New York City Local Reliability Rules and FERC-approved New York City market mitigation rules, as part of the security constrained unit commitment solution for the DAM posted at 11:00 AM of the prior day. **[BP]**
  The local reliability criteria and day-ahead market mitigation rules can be handled either at the regional level under the regional unit commitment model contemplated by RNM or at the local level by local control centers, as is done now in New York. The RTO will work with local control centers to update the reliability model in order to implement the best method of sharing responsibility for reliability commitments and mitigation requirements as knowledge and experience is gained regarding the impacts of local issues on the regional market.[14] Local control centers would make additional reliability commitments or enforce mitigation rules not included in the regional markets if required, but all generation commitments would be coordinated on a regional basis and posted at the designated times that are specified in the regional market design.

- New York's security constrained dispatch optimization includes normal, single and multiple contingency analysis, including PSC mandated thunderstorm watch contingencies, every 5 minutes**. [BP]**
  The regional security-constrained dispatch optimization would include all approved operating contingency analysis and conservative operational requirements as determined by the RTO working with local control centers. Current existing systems would be used to perform local contingency analysis and coordinate with the regional dispatch when needed. Local control actions would be fed back to the regional dispatch.

- New York uses a fully automated security constrained dispatch optimization to control New York Control Area generator dispatch, including generator shifts required to simultaneously solve all active transmission constraints, while taking account of incremental losses on injections at each generation source. **[BP]**

- The New York Real-time energy price is based on Real-time least-cost security-constrained dispatch instructions. The New York process is fully automated**. [BP]**
  As part of the upgrades related to PJM West, PJM is implementing this fall (across existing PJM and PJM West) a new fully automated dispatch

[14] Changes and enhancements to existing mitigation rules would be investigated through a stakeholder process during the design phase in order to ensure consistency across the region.

system. Based on this, RNM contemplates that the regional dispatch would be a fully automated, real-time, least-cost security-constrained dispatch. Local control center existing systems would continue to be used to further refine or supplement the regional solution when required. Prices will be set based on actual generator response to the dispatch instructions.

- New York optimizes phase-angle regulator schedules for all designated facilities in its Day-Ahead Market solution. **[BP]**
  Phase Angle regulators would be optimized for the least cost solution for the region. Local Control centers would have the ability to request changes for local reliability.

- In New York, marginal losses are calculated from the point-of-receipt to the point-of-delivery for all transactions and are included in the TUC. [**BP]**
  Marginal losses could be included in the LMP calculation for the entire region and included in the energy prices or differences in energy price, if stakeholders desire.

- New York incorporates penalty factors (losses) in the Day-ahead dispatch and accounts for marginal losses in its LMP calculation**. [BP]**
  The regional commitment and LMP calculations could include losses, if stakeholders desire.

- New York rarely has the need to invoke TLRs since it continually redispatches its system to support all scheduled transactions and unscheduled loop flows. **[BP]**
  Redispatch would be performed continually for the entire region, including the option to offer external transactions causing unscheduled flow to pay redispatch costs in lieu of curtailment. Therefore the northeast region rarely would have the need to invoke TLRs.

- New York's Day-Ahead Demand Response Program ("DADRP") is fully automated in the Day-ahead market and settlement process and permits the submission of demand-side bid curves analogous to generator bid curves. **[BP]**
  Demand side bids would be included in the day-ahead regional markets.

- New England is developing a Generation Information System ("GIS"). (The GIS is a generation information database and certificate system containing hourly generation information that accounts for certain attributes of energy consumed within the control area and exported outside of the control area.) **[BP]**
  Generator tracking and databases would be done on a regional basis and reporting and certificate tracking could be different by control area, if desired.

- The NEPOOL Tariff allows import transactions in conjunction with Regional Network Service where no OASIS reservations are required. **[BP]**
  Sales into the spot market that use secondary network service would not require OASIS reservations. Secondary service would not require any additional charges for service, although a mechanism to track their impact on ATC at the interfaces would be required.

- New York auctions all TCCs/FTRs**. [BP]**

- New York allocates TCCs/FTRs to market participants paying for transmission upgrades that increase transfer capabilities**.[BP]**

- New York is developing an auction process which will simultaneously optimize multiple-duration TCCs. **[BP]**

- In New York, TCCs/FTRs are always fully funded. Any excess or shortfall is covered by the transmission owners whose rates are automatically adjusted monthly on a formula basis. **[BP]**

- New England auctions FTRs and allocates auction revenues to Auction Revenue Rights holders**. [BP]**
  TCC/FTR allocations/auctions would be developed for the entire region based on the best practices of NY and NE, if desired by stakeholders. Decisions regarding the FTR/TCC distribution can be formulated in parallel with work on developing a regional market.

2. Practices Handled by the Local Control Centers Under RNM.

- New York uses its security constrained dispatch optimization to start and dispatch 10-minute gas turbines that may set LMP. **[BP]**
  Existing local control center tools would be used to handle local constraint control and reserve dispatch and used to supplement and verify regional dispatch instructions.

- New York coordinates daily with the Transmission Operators and provides load, outage, expected generator output, and power flow solutions for each hour of the Day-Ahead Market by 11:00 AM of the prior operating day as required for local transmission owner reliability evaluation. **[BP]**
  The local control centers will facilitate data exchange between the RTO and transmission operators based on appropriate data confidentiality and timing requirements that are specified through a stakeholder process.

- New York has a formal hour-ahead evaluation process (the Balancing Market Evaluation) which adjusts interchange schedules, starts combustion turbines to maintain reserves, adjusts ancillary services schedules and sets prices for hourly ancillary services**. [BP]**

Local control center operators would perform dispatch for reserves and other ancillary services on a forward-looking basis throughout the operating day. There will be no formal interchange schedule analysis that produces hour-ahead prices (i.e., no BME)

- New York payments for reactive services are based on demonstrated generator VAR capabilities**. [BP]**

- New England generators are paid for routine power support according to a prescribed formula contained in the Tariff. **[BP]**

- Under the NEPOOL Tariff, compensation to generators in providing this service [i.e., reactive service] is based on four components: Capacity Cost (CC), Lost Opportunity Cost (LOC), Cost of Energy Consumed (SCL) and Cost of Energy Produced (PC). **[BP]**
  Compensation for the reactive services from generators would be continued separately based on the existing ISO-specific services.

- Under the NEPOOL Tariff, each designated "Black Start Generator" is paid its own fixed monthly revenue requirement. A new generator that is designated as a "Black Start Generator" that does not have sufficient historical data to determine its annual revenue requirement is paid the average black start payment. **[BP]**

- In New England, eligible generators are compensated under a schedule to the NEPOOL tariff for their costs to provide system restoration and planning services. All transmission customers pay for these services. **[BP]**
  Compensation for black start service from generators would be continued separately based on the existing ISO-specific services.

- New York meets its reserve and regulation requirements in both the DAM and HAM through a market-based scheduling process that co-optimizes energy and ancillary service bids. **[BP]**
  The regional market will meet reserve and regulation requirements through co-optimization of all bids and offers.

- New York has locational requirements for capacity in New York City and Long Island. **[BP]**

- New York's proposed UCAP market would allow obligations to be met on a monthly basis. **[BP]**

- New York uses seasonal (summer and winter) capacity values. **[BP]**

- Load management programs either reduce capacity obligations or may participate directly in NYISO ICAP market. **[BP]**

- There are mandatory bid and price caps for certain NYC ICAP suppliers. **[BP]**

- Intermittent and renewable resources can participate in the NYISO ICAP market but are granted exemptions from certain supplier obligations. **[BP]** **The existing separate installed capacity markets and requirements would initially be used in each control area.**

- NEPOOL has approved a pilot that would provide incentive payments to transmission providers for innovative transmission maintenance that reduces congestion. **[BP]**
Implementation of incentive payments or other transmission charges if approved through a stakeholder process and by FERC would be implemented as soon as possible. This has no impact on RNM design.

3. <u>Practices that are mooted by adoption of the PJM platform.</u>

- The New York generator self-scheduling process is a fully automated bid-based process. **[BP]**
Self-scheduling is explicitly permitted under RNM.

- New York generators may submit bids for energy, minimum generation costs, and ancillary services that may vary for each hour of the DAM and HAM, which accommodates the scheduling needs of all generation and demand response technologies. **[BP]**
Hourly bidding is not contemplated due to the ability to self-schedule any time with 20 minutes notice under RNM.

- New York requires all external transactions to provide a bid**. [BP]**
External transactions will be treated identically to generating resources; bidding is permitted but not required, and self-scheduling is permitted.

B. **<u>Best Practices That Are Not Likely to be Initially Included in the RNM at Market Start-up.</u>**

1. <u>Practices that could be implemented at a later date or require longer implementation times.</u>

- New York administers Day-ahead and Real-time bid based markets for 10 minute spinning, 10 minute non-spinning and 30-minute non-spinning reserves, which recognize locational requirements. **[BP]**

- New York uses a fully automated process to clear separate bid-based markets for operating reserves, which are simultaneously optimized with energy and regulation. **[BP]**

- In New England, the Standard Market Design (which PJM also intends to adopt) will include a spinning reserve market **[BP]**
Markets for 10-minute reserves (both spinning and non-spinning) could be implemented within one year after initial energy market start-up. A market for 30-minute reserves could be considered for subsequent implementation.

- In New York, deviations from Day-ahead generation schedules are settled in the balancing market at the 5-minute Real-time LMP prices. **[BP]**
  Shorter accounting intervals (e.g., 5-minute) could be implemented subsequent to start-up based on metering and other infrastructure issues. Load and generation would be required to settle in the same time interval in order to ensure revenue adequacy of settlement calculations.

2. <u>Practices that will not be adopted under RNM.</u>

- The New York Day-ahead regulation market is included in the Day-ahead optimization**. [BP]**
  The regulation requirement will be included in the day-ahead optimization and result in a regulation-clearing price. Day-ahead regulation results will not be financially binding; the regulation market will be a real-time market only.

  In addition, as noted in the discussions above, aspects of two of the best practices in Section A are incompatible with RNM and will not be adopted. These are the Balancing Market Evaluation and the practice of setting real-time prices based on dispatch instructions rather than on the actual generator responses to the dispatch instructions.

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