APPENDIX D

Option 3-M

REGIONAL NETWORKED MARKET CONCEPT

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

September 10, 2001

Option 3-M

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 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.

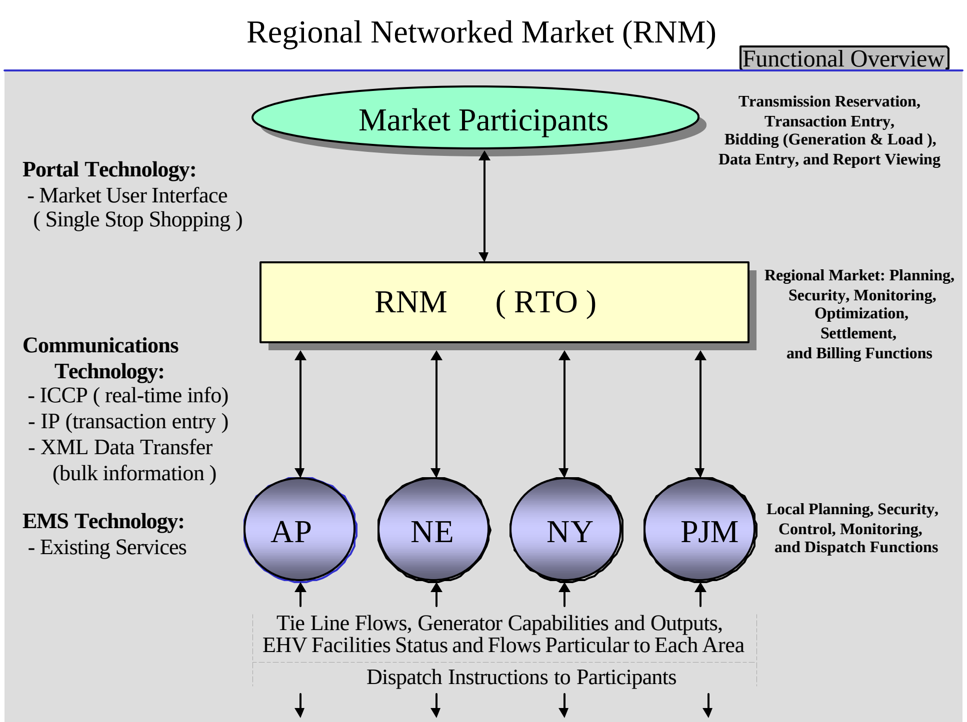


Figure 1

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[1] 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[2], reserve requirements[3] and control area load forecasts[4] 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.

[1] Includes bilateral financial transaction management system (i.e. PJM eSchedules)

[2] Including price-responsive demand and virtual demand bids and virtual supply offers

[3] Including locational reserve requirements and any local reliability requirements specified by the local control area

[4] 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[5] 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[6] 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[7] 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.[8]

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.

[5] 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.
[6] Such operation will be coordinated with the RTO.
[7] 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.
[8] 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[9]

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

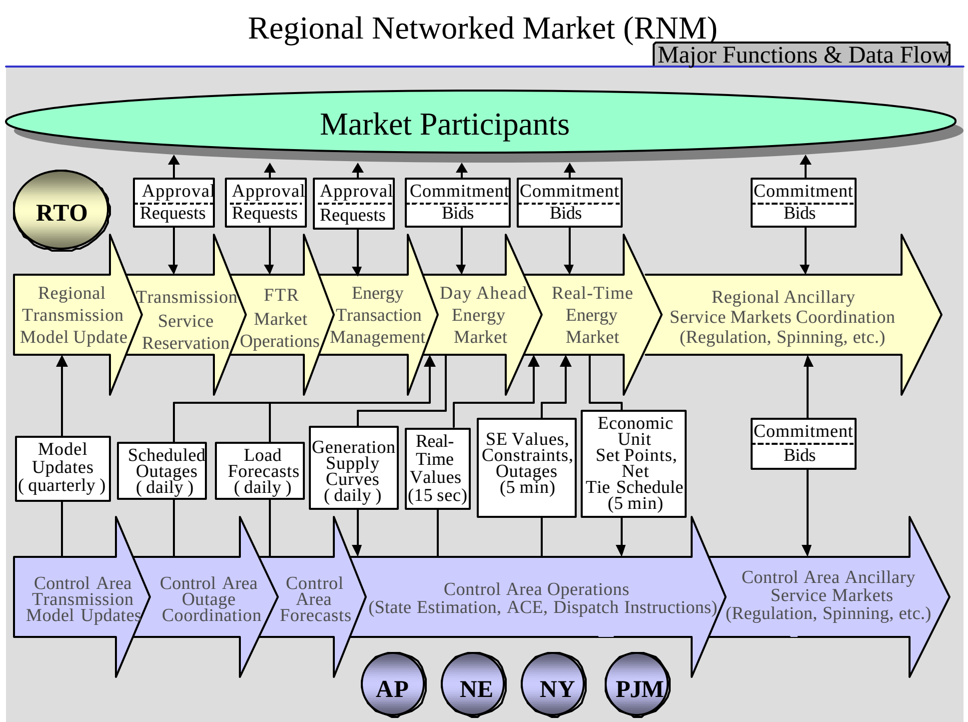


Figure 2

[9] 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.

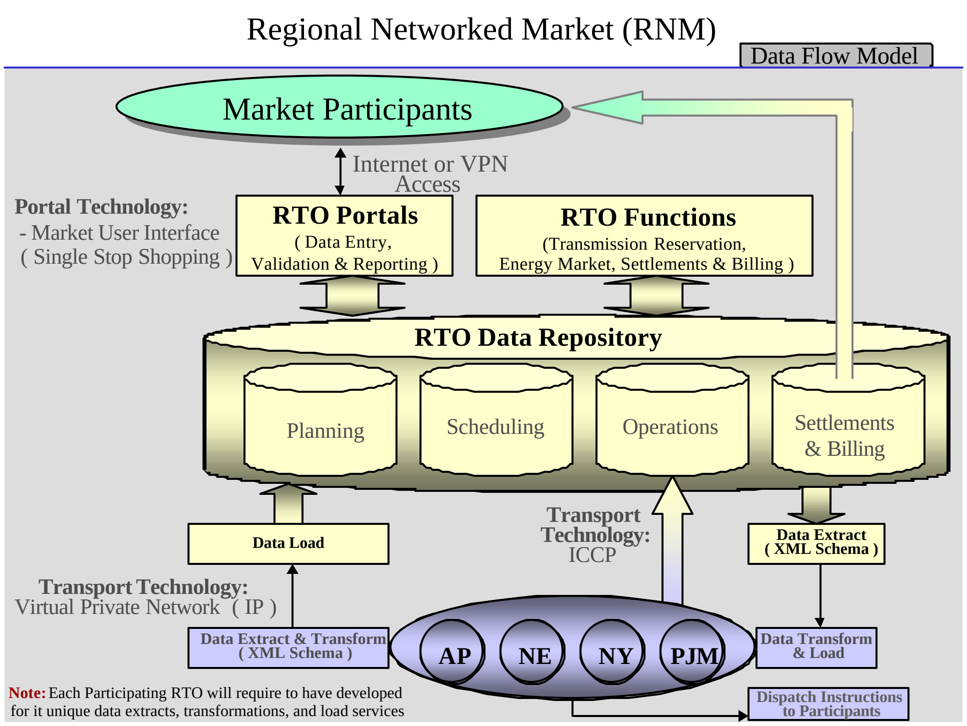


Figure 3

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.

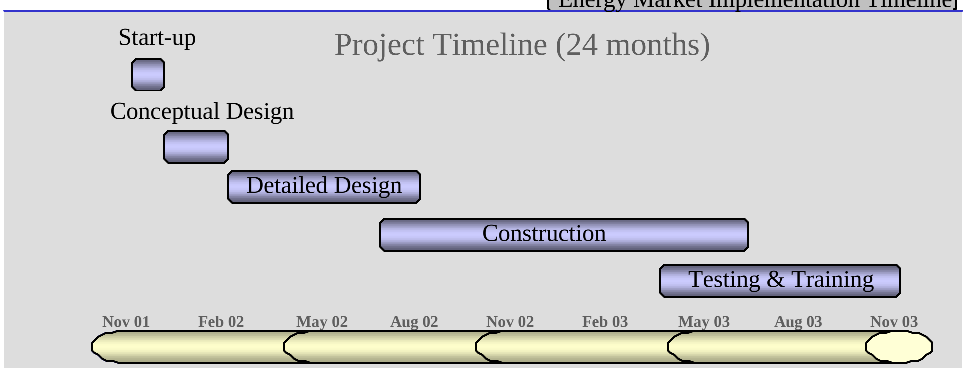
Project Management Timeline

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.

Regional Networked Market (RNM)

Energy Market Implementation Timeline



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