ISO new england

2006

Wholesale Markets Plan

ISO New England ● 2006 Wholesale Markets Plan

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Executive Summary

The *2006 Wholesale Markets Plan* (WMP06) describes ISO New England's plan to continue the development of New England's wholesale electricity markets. The market enhancements detailed in this plan will complement the Standard Market Design (SMD) day-ahead and real-time energy markets and provide a complete set of wholesale electricity markets.

Highlights of the *2006 Wholesale Markets Plan* are as follows:

- Implementation of the Locational Installed Capacity (LICAP) Market, a capacity market that can ensure the near-term and long-term reliability of electric service at a low long-run cost to consumers throughout the region. This will be accomplished by providing prices that, when combined with energy market revenues, offer efficient investment incentives. The implementation of the LICAP Market is contingent upon Federal Energy Regulatory Commission (FERC) approval. LICAP is currently the subject of a hearing at FERC.

- Implementation of Ancillary Services Markets (ASM) for efficient acquisition and pricing of the operating reserves needed to maintain system reliability. This project includes improving market software and market rules to increase demand-response participation in the electricity markets. Customers will be able to respond to changes in wholesale electricity prices and to participate in the wholesale markets on an equal footing with supply.

The current markets send insufficient price signals for ensuring the investment needed for long-term system reliability. Implementing these market enhancements will complete the wholesale markets. They will increase the likelihood that investors will build resources when they are needed and where they can most effectively serve the load (including load in transmission-constrained areas). They also will increase market efficiency by enabling demand resources to participate in the market equally with supply. Additionally, the enhancements will encourage investment in flexible resources that can respond to high loads and system contingencies, such as the loss of a generator or a transmission line. Investment in more flexible resources will reduce the need to take out-of-merit actions to maintain reliability, which in turn will reduce operating-reserve costs and improve energy pricing. These improvements will ultimately assure customers will continue to reliably receive electricity at efficient prices and engender increased confidence in the markets.

The *2006 Wholesale Markets Plan* includes several multi-year projects that began in 2004 and 2005 and were scheduled for completion in 2006. As in previous years, the ISO's annual Wholesale Markets Plan serves as a vehicle for working with the New England Conference of Public Utility Commissioners (NECPUC), the New England Power Pool (NEPOOL), ISO advisors, and FERC to prioritize market improvements. It assists in focusing on the market enhancements determined to hold the highest priority. The document reflects the suggestions of Dr. David Patton, the Independent Market Monitoring Unit (IMMU) for ISO New England, and ISO Chief Economist, Dr. Robert Ethier. Although the ISO prefers consensus on the design and sequencing of the market enhancements outlined in this plan and has attempted to achieve such agreement, the diverse needs of its market stakeholders have made agreement elusive. Certain aspects of this plan, particularly the design of the LICAP Market, remain controversial. Disagreements regarding the LICAP Market design have been presented to FERC, which recently delayed the implementation of LICAP from January 1, 2006, to no earlier than October 1, 2006.

Section 1

Introduction

The move from a vertically integrated monopoly structure for providing New England with electricity to one with competitive markets has resulted in substantial benefits to the region's consumers, including a significant increase in efficiency. For example, the addition of modern, efficient supply has contributed to a 6% reduction in fuel-adjusted energy prices from 2000 to 2004. Since 1999, about 10,000 MW of new gas-fired generation has been constructed to serve the region, displacing the use of oil and less-efficient gas plants, improving overall system reliability, lowering market-clearing prices, and reducing harmful power plant emissions to improve environmental quality. This investment was made by companies that invested in competitive generation, not vertically integrated utilities. Additional benefits were created when ISO New England implemented Standard Market Design on March 1, 2003. Through the locational day-ahead and real-time energy markets that price electrical energy at all pricing locations on the electricity grid, SMD reliably and as efficiently as possible clears short-run energy markets (i.e., it balances demand and supply in real time). These market incentives have improved operating efficiencies, increasing overall availability of power plants.

Despite these benefits, forecasts of demand growth and generator retirements in New England show the current surplus of generating capacity disappearing within the next several years. It is disappearing even sooner in the region's load pockets, which also need contingency-response resources.[1] However, little new investment is currently planned to meet these anticipated needs. Price signals from the existing energy markets are not sufficient to maintain existing efficient capacity or to attract new investment. Market enhancements are needed to supplement the SMD energy market to ensure that they provide efficient price signals to existing plants and to induce new investment. Efficient price signals should assure an adequate supply of energy at all times. The 2006 Wholesale Markets Plan identifies and prioritizes the market improvements for the wholesale electricity markets in New England.

Section 2

Wholesale Electricity Markets: Their Functions and Interrelationships

Efficient wholesale electricity markets require a set of markets that work together to efficiently price the energy and ancillary services needed to reliably provide electricity. The two most important ancillary services are regulation, which balances load and generation on a moment-to-moment basis, and operating reserves, which provide energy for managing power flows on the system if a generator were to trip off-line or a transmission line were to go out of service. Since transmission constraints may limit the ability of the system to deliver energy and ancillary services to different areas on the electricity network, the prices for energy and ancillary services vary by location.

Although the implementation of SMD has been significant in establishing efficient wholesale electricity markets, the wholesale energy market does not clear at price levels that will sustain existing investment and promote new

[1] A load pocket is an area of the system where the transmission capability is not adequate to import capacity from other parts of the system, and load must rely on local generation.

investment. The energy market does not clear at efficient levels because an offer cap on the energy market limits prices to about $1,000/MWh.[2] This offer cap is needed because the wholesale market lacks demand response (DR), which prevents demand from clearing the market when the demand for electricity approaches or exceeds supply. Without such demand response, the energy market is vulnerable to the exercise of market power.

Since the energy market alone is unable to efficiently price electricity during hours of peak use, ISO New England, with FERC approval, is developing improvements to the existing capacity market. These improvements include making the current regional capacity market locational to reflect the different values capacity has in various locations on the system.

The remainder of this section describes the functions of these markets and how, collectively, they efficiently price the services needed for reliable and economic system operation.

2.1 The Energy Market

The energy market is the essential element of the wholesale electricity market. The other markets supplement energy market pricing and assure reliable system operation.

The main function of the energy market is to properly price energy in real time and on a day-ahead basis. Energy prices vary in real time due to the changing amount of consumption and source of production. The SMD energy market balances energy supply and demand and establishes market-clearing prices on a five-minute basis using locational marginal pricing (LMP). LMP allows for the proper pricing of energy at all pricing locations on the electricity grid. The proper pricing of electricity by location means that areas that incur significant transmission losses or cannot import sufficient capacity to serve the demand for energy experience higher prices. These prices provide signals to potential investors that investment is needed in these locations. They also signal consumers to use less electricity.

The ISO commits and dispatches generating units in economic merit order (i.e., the generators with the lowest-price offers are committed and dispatched first, and increasingly higher-priced generators are brought on-line as demand increases). Competition among generators usually drives their offers down to their short-run marginal costs, which are primarily fuel costs. However, since market-clearing prices are based on the last generating unit needed to meet demand, most generators (i.e., generators other than the last one dispatched to meet demand) earn revenues through the energy market in excess of their short-run variable costs for fuel and other operating expenses. These "infra-marginal revenues" contribute to the recovery of fixed costs, the largest portion being capital costs.

2.2 Ancillary Services Markets

Because the status of any major system element—such as a generator, a transmission line, or a load—can suddenly change, system operators need resources able to quickly respond to events that arise at any given moment. For example, a typical real-time operational contingency against which the system operator must protect the system is the sudden loss of a major transmission line or a large generating station. If a large generating station were to trip off-line, the system operator must have sufficient resources to replace this sudden loss because the operator must maintain the balance of supply and demand to maintain the integrity of both the New England transmission system and the systems with which New England is interconnected. Without resources to replace the

[2] Prices can exceed $1,000 due to congestion and losses.

sudden loss of such system elements, load would need to be shed to preserve the real-time balance of supply and demand. In extreme conditions, the entire network could collapse, causing a blackout. Therefore, ancillary services must be available to maintain the reliability of the system in real time. Since transmission constraints may prevent generation in one area from responding to contingencies in another area, the value of ancillary services varies by location.

Resources held in reserve typically provide ancillary services. These resources are held back from producing energy so that they are available for dispatch within 10 or 30 minutes to address a contingency. Because such resources are held back from the energy market, they cannot earn energy revenues. As a result, the system needs a market separate from the energy market to provide an incentive for resources to offer reserve service.

The market for ancillary services is distinct from capacity markets. Only certain types of flexible capacity, such as quick-starting generating capacity and controllable loads that can respond within 10 or 30 minutes, are able to provide ancillary services. The ASM is not designed to replace the capacity market, which supplements the energy market and includes all resources.

The system operator requires a variety of ancillary services, as follows, to maintain real-time system reliability:

- Regulation services, also known as automatic generation control (AGC), which allow the system operator to physically balance supply and demand on a minute-to-minute basis

- 10-Minute Spinning Reserve (TMSR), which is provided by resources already synchronized to the grid to ramp up the system to claimed capacity within 10 minutes[3]

- 10-Minute Nonspinning Reserve (TMNSR), which is provided by resources not currently synchronized to the grid that can be ramped up to claimed capacity within 10 minutes

- 30-Minute Operating Reserve (TMOR), which is provided by resources not currently synchronized to the grid that can be ramped up to claimed capacity within 30 minutes.

To maintain system reliability in specific locations or circumstances, the system operator needs other ancillary services, including the following:

- Voltage Support, formally called Volt Ampere Reactive (VAR) Support, which allows the New England Control Area to maintain transmission voltages within acceptable limits by operating generation resources in a way that produces or absorbs reactive power.

- Black-Start Capability, which is provided by specific generators interconnected to the transmission or distribution system at strategic locations and involves the supply of load to re-energize the transmission system following a systemwide blackout.

Only a few resources are capable of providing these highly specialized services, so that they do not lend themselves to markets. They currently are provided on a cost-of-service basis and will likely continue as such in the near future.

[3] Synchonized resources are on-line resources with electric phases that match those of the electrical system.

2.3 Capacity Market

The offer cap on the energy market prevents it from sending the price signals needed to assure short- and long-term system reliability. The capacity market supplements the energy market by substituting for the price signals lost because of the energy market caps.

The capacity market also responds to the ISO's need to meet its regional Installed Capacity (IC) Requirement and the Northeast Power Coordinating Council (NPCC) and ISO New England resource-planning reliability criterion. This criterion requires the power system to have enough installed capacity to prevent the disconnection of firm customer load more than 1 day in 10 years.[4] The requirement is intended to assure sufficient capacity is virtually always available to meet demand. Since this requirement is imposed outside of the normally functioning energy market, the energy market alone cannot be expected to meet it. The capacity market helps send the proper price signals for assuring the system's installed capacity meets this standard.

Section 3

2006 Update of the 2005 Wholesale Markets Plan

The ISO has met the commitments in its *2005 Wholesale Markets Plan* and has completed all market enhancements planned for completion in 2005. Some projects initiated in a particular year have a lifecycle longer than one year, and the ISO's progress on these projects is consistent with the 2005 plan. The ISO also conducted several other projects not discussed in the 2005 plan. This section discusses work completed on the 2005 planned activities as well as the additional projects conducted during the year.

The 2005 report detailed the ISO's plans to conduct the following activities:

- Substantially improve the capacity market
- Create wholesale markets for ancillary services
- Provide the infrastructure for direct participation by demand in the energy markets and the Ancillary Services Markets
- Reduce seams with New York in the energy and capacity markets
- Improve the integration of operating decisions and market pricing
- Implement the short-term recommendations of the Cold Snap Task Force[5]

[4] For more information on the IC Requirement, refer to the ISO's *Regional System Plan 2005* at <http://www.iso-ne.com/trans/rsp/index.html>.

[5] The ISO and its stakeholders formed the Cold Snap Task Force in 2004 to review existing market rules and operating procedures, find short-term remedial improvements to the procedures, and address some of the recommendations identified within the *January 2004 Cold Snap Report*, written as a response to the extreme cold weather events that occurred during the cold snap of January 14–16, 2004 (January 2004 Cold Snap).

The completed projects include conducting the Interregional Transaction Scheduling (formerly called Virtual Regional Dispatch) Pilot Project with New York, conducting the Day-Ahead Load-Response Project, and developing and writing Short-Term Cold Snap Recommendations.

The other projects underway include the Locational Installed Capacity Market, the Ancillary Services Market, and Special Case Nodal Pricing (SCNP). Based on stakeholder feedback, the ISO divided the Ancillary Services Market Project into two phases. Phase 1 is scheduled for delivery in October 2005, and Phase 2 is scheduled for completion in 2006.

Table 1 summarizes the *2005 Wholesale Markets Plan* commitments and the progress toward meeting these commitments.

TABLE 1
2005 Wholesale Market Plan
Commitments

Project	Original Completion Date Commitment[a]	Status Update
Locational Installed Capacity	January 2006	FERC has delayed the implementation of LICAP until October 2006 at the earliest
Ancillary Services Market	October 2005	Phase 1 – on schedule for October 2005 Phase 2 – no earlier than October 2006
Interregional Transaction Scheduling Pilot	Q1 2005	Completed
Special Case Nodal Pricing	October 2005 (linked to ASM)	Linked to Phase 2 of ASM
Day-Ahead Load Response	June 2005	Completed
Short-Term Cold Snap Recommendations	December 2004	Completed

[a] Other activities in the *2005 Wholesale Markets Plan* did not have time commitments.

In addition to these projects, the ISO implemented several additional market enhancements, as follows:

- Partial delisting, which enables resources to use a portion of a generating unit to support the sale of capacity to external control areas[6]
- Assignment of real-time operating-reserve charges to real-time load obligations instead of real-time deviations
- Negative bidding for Financial Transmission Rights (FTRs) (i.e., financial instruments market participants can buy to help them hedge the price risk of day-ahead congestion caused by constraints on the transmission system)
- Changes in the methodology for the carry-over and allocation of congestion revenue

[6] Delisting is a temporary removal of a facility from the capacity market.

A major project added to the plan in early 2005 (following the publication of the *2005 Wholesale Markets Plan*) was the creation of the Southwest Connecticut (SWCT) energy zone, pursuant to a FERC order.[7] As part of its July 2, 2004, Locational Installed Capacity Market filing, and at the request of FERC, the ISO provided evidence to support the creation of a SWCT Load Zone at the same time as the implementation of the LICAP market. FERC approved the ISO's proposal in November 2004. The timing of the implementation of the load zone is currently before the commission.

Section 4

2006 Wholesale Markets Plan Implementation Approach and Schedule

The 2006 plan is a continuation of several multi-year projects begun in 2005 and scheduled for completion in 2006. Section 4 and Table 2 summarize the project-release schedule under ISO New England's *2006 Wholesale Markets Plan*. Section 5 of this plan describes in detail each of the projects listed in Table 2.

[7] Devon Power LLC, *et al.*, 109 FERC ¶61,156 (2004).

TABLE 2

Project Release Schedule for WMP06 [(a), (b)]

Project	Project Status	Market Design Schedule	Earliest Implementation Date	Internal Resource Requirement
Locational Installed Capacity	Implementation delayed until October 1, 2006, at the earliest	Awaiting FERC approval	October 1, 2006	Medium
Southwest Connecticut Load Zone	Development underway	Awaiting FERC approval	January 1, 2006	High
Interregional Transaction Scheduling Pilot Phase 2	Design effort underway	Q4 2005	Q1 2006	Medium
Ancillary Services Markets Phase 2 - Locational forward reserves - Joint optimization - Demand participation	Design effort underway	Q4 2005	October 2006	High
Special Case Nodal Pricing Phase 1 (nondispatchable option)	Design effort underway	Q4 2005	Q1 2006	Medium
Special Case Nodal Pricing Phase 2 (dispatachable option)	Design effort underway	Q1 2006	October 2006 (will be implemented as part of ASM Phase 2)	High
Demand-Response Reserves Pilot Program	Rules approved by stakeholders, June 2005	Q4 2005	October 2006	Medium
Pricing of External Nodes (1385)	Design effort underway	Q4 2005	October 2006	Medium
Day-Ahead Load-Response Program (Integrate day-ahead load-response offers into the day-ahead market)	Project design to commence Q4 2005	Q2 2006	June 2007	High
Partial Delisting Enhancements	Design effort underway	Q3 2006	June 2007	High
Combined Cycle Modeling	Design effort underway	Q1 2006	May 2006	High
Long-Term Cold Snap Recommendations	Stakeholder discussions underway	Subject to stakeholder discussions	Subject to stakeholder discussions	TBD

[(a)] WMP06 projects, including implementation dates, are described as of September 2005. Specific elements may change as a result of the stakeholder process, FERC approvals, practices in neighboring regions, and other factors. The timeframe presented for each enhancement is tentative and based on current estimates of the scope of work and level of effort required. Successful completion of the projects included in each release requires the ISO and its market participants to agree on the market design for each enhancement with sufficient lead-time for software development to support the release schedule. The market design schedule reflects the date by which agreement for a project must be reached to meet this schedule and reflects the earliest date at which a firm project plan (scope, schedule, and budget) will be provided.

[(b)] A minimum of six months is required between the implementation of the capacity market and the Ancillary Services Market. Delays in regulatory approvals in either or both of these activities will impact the WMP06 schedule.

The ISO has conducted the following tasks to improve its effectiveness and efficiency in developing and implementing market enhancements:

- Implemented a software-release approach to facilitate effective planning
- Optimized the use of information technology resources
- Enhanced operator training
- Thoroughly tested changes to the markets (including external market trials with participants, when applicable)
- Certified pricing modules in pricing software
- Initiated more comprehensive system audits

This approach packages market changes into discrete software releases with advanced notice for each release. The advanced notice benefits market participants by enabling them to prepare their business strategies and market operations to accommodate these changes, minimize operational expenses, and reduce the risks associated with frequent releases.

A critical factor in meeting the *2006 Wholesale Markets Plan* release schedules is for stakeholders to reach consensus on the details of a market design with sufficient lead-time for system and software development. If they cannot reach consensus on a design, a project will either be delayed or submitted to FERC without stakeholder approval. Additionally, if a significant design change occurs close to the design's scheduled release date, a market project may not be ready for implementation as scheduled. To obtain the benefits associated with the development of a multi-year plan, all stakeholders must reach general agreement on design specifics well in advance of the scheduled release date.

Section 5

Project Descriptions

This section describes the projects listed in Table 2 in more detail and provides the status of each project. The market enhancements described continue to improve the wholesale market design by efficiently pricing the products and services needed to reliably operate the power system, which enables market participants to make efficient consumption, production, and investment decisions. Since the wholesale electricity market is a complex set of separate but related markets for energy, capacity, and ancillary services, the markets must complement each other. The completion of the projects in this plan will create a more thorough set of wholesale electricity markets that efficiently prices the products and services needed for reliable short-term operation of the power system and long-term resource adequacy.

5.1 Locational Installed Capacity

On March 1, 2004, the ISO filed a locational ICAP (LICAP) design with FERC that included a sloped demand curve to address ICAP price volatility, a locational clearing process to appropriately price capacity on a locational basis, and a capacity transfer-rights mechanism to allow for nonuniform allocations of capacity imports into a region or exports from a region. FERC approved the overarching design of the ISO's LICAP proposal (the use of a downward-sloped demand curve and pricing within constrained regions), but set certain issues for hearing, including the specific parameters of the demand curve, the method of calculating capacity transfer limits, and the allocation of capacity transfer rights. In addition, the commission directed the ISO to submit a further filing addressing the commission's proposal to create a separate, import-constrained installed capacity region for Southwest Connecticut.

On June 15, 2005, FERC's Administrative Law Judge (ALJ) issued an initial decision in the LICAP proceeding. While the judge's initial order accepted most of ISO New England's proposed LICAP design, she did not accept the ISO's "shortage-hour" concept, which would have required all resources to be available during times of shortage to receive LICAP payment. On August 10, 2004, FERC issued an order delaying the implementation of LICAP until October 1, 2006. FERC's ultimate disposition of this case will affect not only the implementation of the capacity market, but, potentially, the timing of all of WMP06 projects as well. The ISO is prepared to implement the LICAP Market on October 1, 2006, if so ordered by FERC. The ISO is also committed to actively participate in the LICAP proceedings, as may be ordered further by FERC.

5.2 Southwest Connecticut Load Zone

Work is currently underway to implement a SWCT Load Zone upon LICAP implementation. The FERC order delaying LICAP created ambiguity concerning whether the implementation date of the SWCT load zone should be January 1, 2006, the implementation date for LICAP, or possibly, January 1, 2007. The ISO is seeking clarification on FERC's intended date for implementation of the SWCT Load Zone. Implementing the SWCT load zone separately from LICAP requires the consideration of the impacts that the creation of a new zone has on the long-term FTR auction. These issues are described in detail in the ISO's filings to the commission on exception to the ALJ's LICAP decision.[8]

5.3 Interregional Transaction Scheduling Pilot Phase 2

The interchange of electricity across external interfaces is the most fundamental seams issue between the New York and New England control areas. To reduce the impediments to trade across external interfaces, the New York ISO (NYISO) and ISO New England are proposing Interregional Transaction Scheduling (ITS) (formerly called Virtual Regional Dispatch), the exchange of energy between New York and New England based upon market-price differentials.

An efficient market attains price convergence at uncongested interfaces. At such interfaces, market participants can quickly arbitrage large price differences, ensuring the flow of energy from the lower-priced area to the higher-priced area and price convergence. However, prices at the New York and New England border rarely converge, and the efficiency of both markets suffers. The markets could realize savings by mitigating this

[8] Devon Power LLC, *et al.*, "Motion for Expedited Consideration and Issuance of Notice of the Timing of Commission Action, and Informational Filing of ISO New England Inc.," Docket No. ER03-563-030, filed July 15, 2005.

inefficiency; both generators and consumers benefit when generation produced in a lower-priced region can be sold to a higher-priced region. Such benefits accrue until prices in the regions converge.

This market inefficiency is reflected in persistent price differences at uncongested interfaces and counterintuitive flows in both directions. As Dr. David Patton reported in 2002, the two markets have not been able to attain consistent price convergence at external interfaces. Transactions respond sluggishly to large price differentials, and net flows often run counter to the price difference between the two regions (i.e., higher-priced energy sometimes flows toward the lower-priced region).

The ISO is designing ITS to use the load bids and supply offers from New York and New England to more efficiently meet the combined load of the two markets than is currently possible using physical transactions between the regions.

Under the ITS design proposal, the physical interchange between NYISO and ISO New England will be adjusted automatically based on the relative prices in the two markets (i.e., the marginal cost of generation) to maximize the use of the interface and to facilitate price convergence between the markets. The objective is to allow the control areas to jointly realize the benefits of a larger market while maintaining separate dispatches.

ITS is an important component of the market design, especially since both New York and New England have implemented shortage pricing. Shortage pricing should occur only in the presence of true shortages, not when shortages are only apparent and can be partly attributed to inefficient use of the interface. ITS is intended to ensure shortage pricing only occurs when truly necessary by maximizing the use of the interface.

Market participants have expressed concerns about the ITS proposal, and NYISO and ISO New England will work with participants to determine whether alternative proposals based on participant transactions can achieve the same levels of efficiency as the current ITS concept. To this end, NYISO and ISO New England have received potentially viable alternative methodologies from their stakeholders. Both ISOs will hold further stakeholder meetings to finalize the technical definitions of the alternatives and to work toward joint stakeholder acceptance of a proposal.

ISO New England and NEPOOL submitted a joint filing requesting the commission to expedite its consideration of the NEPOOL pilot of Interregional Transaction Scheduling. FERC approved the pilot, and NYISO and ISO New England conducted the first pilot tests on April 20–21, 2005. The pilot was a manual implementation of what is anticipated to be a highly automated process and successfully demonstrated the initial feasibility of adjusting interchange. A report on the findings of the pilot tests will be issued in fall 2005, and the ISOs and their participants will discuss the results of the tests at that time. The second pilot test will incorporate the insights learned to date and the feedback of the participants. Whereas the first pilot tests focused on operational issues, the second pilot test is anticipated to include the feasibility of using ITS to achieve price convergence.

5.4 Ancillary Services Markets

Like the locational capacity market, the Ancillary Services Markets are designed to produce prices that reflect the correct value of transmission, energy, and reserve resources, regionwide and locationally. The ASM project also provides the infrastructure to support increased demand participation in the energy and reserves market.

The Ancillary Services Markets will build upon the existing Forward Reserves Market to provide the locational price signals for resources offering operating reserves and contingency support.[9] In addition to the implementation of a locational Forward Reserves Market and the joint optimization of the supply of energy and reserves in real time, the ASM project includes market-design changes that will enable dispatchable loads to participate in the real-time energy market and ASM and improve the efficiency of the regulation market.

The ISO originally proposed to develop and implement the ASM by October 2005. However, a broad group of the region's stakeholders requested an extension of the schedule to review the ASM and more fully consider the impact of the proposed changes. Dialogue with the stakeholders during 2005 has resulted in a widely supported plan to phase in the implementation of the ASM project over a longer period. This has resulted in dividing the implementation of the ASM in two phases:

- ASM Phase 1, to be implemented on October 1, 2005, which includes the implementation of the regulation market redesign, re-offer period enhancements, and the ability for external transactions to set price.

- ASM Phase 2, which could be implemented no earlier than October 1, 2006, and include the implementation of the locational Forward Reserves Market, real-time hourly reserves pricing, and demand participation in the reserves market.

As explained in greater detail below, the infrastructure changes necessary to implement Special Case Nodal Pricing for dispatchable resources have been included as part of ASM Phase 2.

5.4.1 Regulation Market Redesign (ASM Phase 1)

The existing regulation market will be improved by adding two key features of the regulation market design used in New England's interim market. One feature is determining the regulation clearing price in real time rather than day ahead. The second is including the generator's actual response to the regulation signals sent by the ISO (commonly known as "mileage" payments) in the price of regulation services. These improvements will benefit the market in the following ways:

- Enlarging the pool of resources eligible to supply regulation service to the market by enabling all resources on-line and generating in real time to participate in the regulation market, rather than just those selected day-ahead or self-scheduled in the regulation market

- Establishing more efficient and transparent market-based prices for such service that account for the actual amount of regulation service the resource pool provides to the market

The regulation market will continue to be a real-time market only, and the quantity will be "megawatts of regulation available in five minutes." Regulation will not be cleared in the day-ahead market. The regulation-clearing price will be set to the offer price of the most expensive resource selected to provide regulation. Generators providing regulation service will earn service payments based on the regulation clearing price and their responses to the regulation signals. This is more efficient than the current system, as it more accurately prices the service resource owners actually provide. A generating resource deemed to be operating out of economic-merit order on an hourly basis to provide regulation will receive an additional opportunity cost payment.

[9] The Forward Reserves Market includes generating resources that provide nonsynchronized (nonspinning) 10-minute and 30-minute reserves.

5.4.2 Re-Offer Period (ASM Phase 1)

The Day-Ahead Energy Market will be modified to allow participants to submit revised incremental energy offers for assets that cleared in the Day-Ahead Energy Market during the re-offer period. This improvement will allow market participants to more precisely adjust their energy offers based on more up-to-date information, reducing uncertainty and risk. Reducing the risks faced by market participants results in lower overall prices. The only assets that currently can take this action are those that did not clear in the day-ahead market. The real-time scheduling, dispatch, and market-pricing applications will use these revised incremental energy offers. This new functionality will allow generating resources to better manage their real-time risks, such as fuel-price risks. Implementation of this portion of the ASM is contingent upon a rule change to address market power concerns FERC is currently considering.

5.4.3 External Transactions Setting the Price (ASM Phase 1)

This ASM project will include software to allow eligible external dispatchable transactions to be evaluated in the dispatch software and, if marginal (within some predefined bounds), to set dispatch rates. In so doing, the transaction becomes eligible to set the locational marginal price to reflect the differing costs of congestion and losses at various points on the bulk power grid. This, in turn, results in more efficient pricing and use of resources.

5.4.4 Locational Forward Reserves Market (ASM Phase 2)

The current Forward Reserves Market will be enhanced by adding three new features. It will become locational, allow for bilateral trading, and allow for demand-resource participation. To add a locational component, the Forward Reserves Market requirements and clearing process will be modified based on the forecasted operational requirements for commitment and dispatch to meet the second-contingency requirements for the “reserve zones” of the power system. These requirements will be observed in both forward-market clearing and real-time dispatch. By introducing a locational feature to the Forward Reserves Market, reserve-market prices will reflect the locational value of quick-start resources.

The Forward Reserves Market will also be modified to allow participants to submit “portfolio” bids for evaluation and clearing in the market and to trade these obligations via bilateral arrangements. All obligations will need to be converted to physical resources by the bidding deadline for the day-ahead market. The infrastructure improvements to enable demand to participate directly in the energy and reserves market will enable demand to participate in the Forward Reserves Market as well. Enabling bilateral trading and allowing qualified demand resources to participate in the Forward Reserves Market enlarges the pool of resources that could provide reserves, which should increase competition and improve efficiency.

5.4.5 Real-Time Hourly Reserves Pricing (ASM Phase 2)

The dispatch algorithm currently used in the energy market does not recognize the regional or locational reserve requirements to which the ISO must adhere when operating the system. If the energy dispatch alone does not provide sufficient reserves, system operators must manually dispatch the system to provide those reserves. Although such manual interventions are necessary at this time to preserve system reliability, the decisions made by the system operators are not transparent to market participants, and the resulting interventions may not be optimal (i.e., a less-expensive resource may have been available to provide reserves but was not selected).

To improve the efficiency of dispatch decisions to provide needed reserves and jointly optimize the dispatch of energy and reserves, the ASM project will include both regional and locational reserve constraints in the energy dispatch. An hourly clearing price for reserves will be created when an opportunity cost for providing reserves exists. This price will be paid to all those providing energy or resources on the system. When the system does not have enough reserves, shortage pricing will include the value of the foregone reserves in both the energy and reserve price. Quick-start resources, when economic for supplying energy or reserves or when needed to manage transmission constraints, will continue to be committed and dispatched by the real-time dispatch software.

5.4.6 Demand-side Participation in the Energy and Reserves Markets (ASM Phase 2)

One of the ISO's goals is to enable full demand response in the wholesale markets. Once integrated into real-time operations, demand resources will have the potential to more efficiently balance load and generation and offer reserve services. DR can improve the efficiency of the energy market by reducing consumption during times of high prices. DR participation in the reserves market can improve the efficiency of this market by increasing the resources available to participate in the market, making the market more competitive. Indeed, demand resources in the ISO's Demand Response Programs have already demonstrated the ability to respond rapidly to ISO dispatcher instructions and provide reserves. These additional opportunities for DR should increase the amount of DR in the market. Accordingly, the software infrastructure needed to support the ability of demand-side resources to participate in the energy and the reserves market will be implemented as part of the Ancillary Services Markets project.

5.5 Special Case Nodal Pricing

In conjunction with ASM Phase 2, the ISO plans to implement Special Case Nodal Pricing, which will permit qualifying customers to settle at nodal prices. Individual end-use metered customers that have a load of at least five megawatts, are connected to a single node, and comply with applicable ISO operating procedures will be eligible to participate in Special Case Nodal Pricing. Eligible customers could choose a nondispatchable or a dispatchable option.

Customers opting for dispatchable status will be considered ICAP resources and eligible to receive ICAP credit. They will need to be available for scheduling and dispatch during the operating day according to their bid or if the ISO were to declare an emergency condition—a specific action in OP 4.[10] Special Case Nodal Pricing will increase demand resources in the market and better integrate demand response directly into the market design without requiring nonparticipants to subsidize program participants. Because the infrastructure changes necessary to implement SCNP for dispatchable resources are related to the changes needed to implement ASM Phase 2, SCNP for dispatchable resources will be included as part of ASM Phase 2, which the ISO does not plan to have in place until October 2006 at the earliest (see Table 2).

[10] Under OP 4 conditions, the system operator must take special steps to prevent curtailment of firm customer load. These actions include reducing operating reserves, reducing voltages, importing emergency power, activating emergency demand response to make capacity available, and taking other emergency measures while still maintaining transmission system reliability. See <http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html>.

To address the delay in implementing SCNP due to splitting the ASM project into two phases, ISO New England recently proposed to develop SCNP for nondispatchable resources as a separate project that could be implemented sooner than ASM Phase 2. NEPOOL agreed to implement SCNP for nondispatchable resources on a faster track provided all implementation issues are resolved satisfactorily and doing so will not have an adverse impact on the schedule for Phase 2 of the ASM project. Pending stakeholder and FERC approval of market rules, ISO is currently working toward earlier implementation of SCNP for nondispatchable resources.

5.6 Demand-Response Reserves Pilot Project

While individual generators are substantially large, individual DR resources are relatively small. Thus, it is not cost effective for many DR resources to use the sophisticated metering and communication technology required of large generators to enable system operators to monitor system status and to communicate dispatch instructions. Requiring DR to meet the same technology requirements as the generators effectively would prohibit the participation of a large number of demand resources in the ASM.

ISO New England will be working to address these barriers by implementing a Demand-Response Reserves Pilot Program (DRR Pilot). Working with staff from the national laboratories funded by the U.S. Department of Energy, the DRR Pilot will determine the ability of demand resources to meet operational requirements for reserve resources and will investigate cost-effective communication and telemetry solutions that would allow such resources to participate in the market. The specific goals of the DRR Pilot are as follows:

- Demonstrate whether DR resources reliably can provide reserves, specifically 30-minute operating-reserve and 10-minute nonsynchronized reserve services

- Determine the requirements for the level and type of control room communications, dispatch, metering, and telemetry sufficient for DR resources providing reserve services

- Identify and evaluate communications and telemetry solutions that cost less than those required for conventional large-scale generation

NEPOOL approved DRR Pilot rules in June 2005. A FERC filing will be made in the second half of 2005, and pilot implementation will likely occur in 2006. Depending on the results of the DRR Pilot, modifications to ASM rules, business procedures, and infrastructure protocols may be proposed, if necessary, to enable effective and efficient participation of demand resources in reserve markets. Once the DRR Pilot program is implemented, it will take time to implement the entire process of evaluating DR resource performance, the alternative communications and telemetry solutions, and the modifications to reserve market rules that will incorporate DRR Pilot results.

5.7 Integration of Day-Ahead Load-Response Offers into the Day-Ahead Market

On June 1, 2005, ISO New England implemented a Day-Ahead Load-Response Program (DALRP) for customers that can offer load reductions concurrent with the day-ahead wholesale electricity market. In contrast to the previously established Real-Time Demand Response Programs, the DALRP contributes to greater market efficiency by allowing the customer or enrolling participant to specify the wholesale electricity price at which the customer(s) is (are) willing to curtail load.

The current program design uses a "sequential-clearing" methodology to determine whether to accept a DALRP offer. With the sequential-clearing methodology, DALRP offers are accepted after an approved solution to the Day-Ahead Energy Market has been determined. DALRP offers are compared to the day-ahead LMP resulting from the approved Day-Ahead Energy Market solution. If the price of a DALRP offer (including any curtailment initiation price) were less than the day-ahead LMP, the DALRP offer would clear. Since DALRP offers are cleared after the Day-Ahead Energy Market solution has been determined, they are not "integrated" directly into the day-ahead market clearing process; DALRP offers do not directly compete with supply offers in the Day-Ahead Energy Market and do not directly affect Day-Ahead Energy Market prices.

FERC initially rejected the sequential-clearing methodology on December 21, 2004.[11] In a subsequent compliance filing following a technical conference convened by FERC, however, ISO New England and NEPOOL maintained the sequential method was cost effective.[12] The reasoning was based on the level of expected participation in the program and the lack of current system and metering infrastructure to integrate load-curtailment offers as part of the supply function in the day-ahead market and in real-time settlement. NEPOOL participants voted to support the sequential approach, effective June 1, 2005, to be replaced by an integrated-clearing approach that will be implemented after the infrastructure for direct demand participation is in place as part of the ASM project.

On April 18, 2005, the commission directed ISO New England to implement the sequential-clearing methodology by June 1, 2005. It also directed the implementation of an integrated clearing methodology no later than one year following the implementation of asset-related demands in the ASM upgrade, or by June 1, 2007, whichever is earlier.[13,14] FERC directed the ISO to file a plan and any necessary conforming tariff revisions for the implementation of an integrated clearing approach no later than 60 days prior to the implementation of the approach.

5.8 Partial Delisting Enhancements

Standard Market Design originally did not allow resources to partially delist to support the sale of capacity to external control areas from a partial unit. In June 2005, the ISO successfully implemented a simplified mechanism for suppliers to partially delist units and sell capacity to other control areas. FERC approved the simplified mechanism, but requested additional changes and enhancements.[15] The ISO will work with all stakeholders to respond to that order. By allowing resources to partially delist and sell capacity to other control areas, such units may be utilized more efficiently.

Three requested enhancements remain. The first enhancement will allow suppliers to sell capacity from a delisted unit across multiple interfaces. For example, a unit may sell capacity across both the New York AC interface and the Cross-Sound Cable. The ISO will accommodate the first enhancement coincident with the implementation of LICAP or such other improved capacity market ordered by FERC.

The second enhancement will eliminate the requirement for partially delisted units to offer all their capacity into the Day-Ahead Energy Market. The ISO has a pending rehearing motion on this issue.

[11] ISO New England Inc., 109 FERC ¶61,314 (2004).

[12] Compliance Filing of the New England Power Pool Participants Committee and ISO New England Inc., Docket No. ER04-1255-000, February 18, 2005.

[13] An asset-related demand is a new asset class the ISO is developing. This asset would permit a demand (e.g., a large industrial end-use customer) to fully and directly participate in energy and ancillary services markets.

[14] New England Power Pool and ISO New England Inc., 111 FERC ¶61,064 (2005).

[15] New England Power Pool and ISO New England Inc., 110 FERC ¶61,396 (2005).

Third, the ISO's current partial delisting provisions do not allow partially delisted resources to participate in the Forward Reserves Market. FERC asked the ISO either to explain why this feature is required or to allow partially delisted units to participate in the Forward Reserves Market. The ISO examined the issue at more length in light of FERC's request and found no workable alternatives and no market impact of the current practice. The ISO will continue to require resources providing forward reserves to be fully listed ICAP resources.

5.9 Long Island Power Authority/Northeast Utilities Line Connecting Long Island and Southwest Connecticut

The Long Island Power Authority (LIPA) has requested the NYISO and ISO New England to work with it to develop the tariff and rule changes as well as the software changes necessary to separately schedule and dispatch transactions over the 1385 line that connects Southwest Connecticut and Long Island. ISO New England, NYISO, and LIPA are developing a proposal that addresses the relevant market rules and operational and tariff issues. ISO New England will bring this issue to its stakeholders in late 2005; the project's implementation date is currently scheduled for fall 2006. Enabling separate scheduling and dispatching of transactions over the 1385 line could improve the efficiency of transactions between Long Island and Southwest Connecticut.

Section 6

Policy Initiatives

For the improved price signals from the market enhancements in WMP06 to be effective, the entire institutional framework underlying the electricity markets must support efficient wholesale markets. To this end, the ISO is undertaking a number of policy initiatives.

6.1 Wholesale-Retail Market Linkage Issues

The ability of consumers to capture the benefits of competitive electricity markets depends on ensuring consistency between the design and administration of the competitive wholesale market and the retail markets. It also depends on having associated regulatory frameworks that provide end-use customers with reliable and reasonably priced electricity service. Inconsistencies between wholesale and retail market policies result in market inefficiencies. In New England, for example, wholesale markets are designed to reflect geographical and temporal differences in power costs, which provide economic incentives for optimal investments and demand-response levels where and when they are most beneficial. However, these efforts are currently neutralized by retail rate designs, governed by state regulatory policy, that mask these geographical and temporal cost differences.

State policies affecting the pricing and procurement of "provider of last resort" (POLR) services could be modified to better align with the wholesale market structure, which would improve the efficiency of the overall electricity market.[16] For example, greater use of dynamic pricing—retail prices that vary more directly with changes in wholesale spot-market energy prices—applied to price-responsive customers will likely be the most direct and cost-effective way to increase the responsiveness of demand to wholesale spot-market energy prices. This type of pricing will have the most value during periods of capacity shortages and price spikes. To capture these benefits,

[16] POLR services are also known as Standard Offer, Transitional Standard Offer, Default, Basic Electric, or Last Resort Service. In states that allow retail competition, POLR service is provided to end-use customers who have not elected to take generation service from a competitive retail supplier.

ISO New England will work with market participants and state policymakers to improve the linkages between wholesale and retail markets in the area of demand response. The ISO is holding a conference in October 2005 to discuss these issues and plans to issue a white paper in 2005 on this topic.

6.2 Installed Capacity Methodology Review

Over the next 18 months, ISO New England and the region's stakeholders and regulators will review the methodology used to calculate the Installed Capacity Requirement (see Section 2.3). A part of this review will be to consider how to integrate any methodology changes into the capacity market to assure the market procures the capacity needed for reliable system operation. This review will be ongoing throughout 2006 with the intent of implementation for Power Year 2007/2008.

6.3 Long-Term Recommendations of the Cold Snap Task Force

The ISO has developed short-term improvements to address problems associated with the events that occurred during the January 2004 Cold Snap. FERC has approved these improvements, subject to certain issues set for settlement and hearing. All parties have recognized additional market improvements may be needed to better address the problems identified in the January 2004 Cold Snap Report. These issues include assuring that the following conditions are met:

- Prices for energy and reserves are appropriate to ensure supply meets the demand for electricity and maintains bulk power reliability, especially under severe cold weather conditions.
- The ISO has sufficient information to reliably operate the system.
- Generators have the incentives or are subject to reasonable requirements to be available during such severe weather conditions.
- Fuel-price volatility, fuel-delivery uncertainty, unit-performance uncertainty, and fuel constraints that may impair or otherwise affect resource performance and operating characteristics do not adversely affect the reliability of the system.

The ISO is currently working with its stakeholders to define the scope of additional enhancements that address these issues. After the scope is defined, the ISO and its stakeholders will define the priorities and schedule for developing the enhancements that would improve system reliability during severe weather conditions.

Typically, the distribution company or a state agency (such as the public utilities commission) procures wholesale generation to supply POLR load. The manner in which such generation is procured, the terms and conditions of the power sale/purchase agreement, and the tariff structure through which such generation is sold to POLR customers are subject to state jurisdiction.

6.4 Improving Market Pricing by Reducing Out-of-Merit Commitment

In New England, a weak transmission system and a lack of flexible generating resources within load pockets often require system operators to commit resources out of merit to satisfy power system reliability criteria. The ISO has initiated a project to identify ways to reduce these commitments. This work will identify and address those factors that impede the market from providing, in response to price signals, the resources required to operate the power grid reliably.

A primary focus will be on power system infrastructure. For example, many of the interfaces in New England are voltage limited. Generating resources are frequently used to control voltage pre- and post-contingency, but the market cannot efficiently buy and sell reactive power, and generating resources provide reactive power only when providing energy. This distorts energy pricing. Thus, using transmission equipment to resolve voltage issues may be preferred, freeing generators to buy and sell megawatts without distorting energy pricing. The ISO will continue to work with its stakeholders to identify key upgrades that would reduce or eliminate the need for out-of-market commitment of generation to control voltage and thus increase the overall cost effectiveness of meeting the system's reactive power requirements.

The ISO is also investigating a new combined-cycle unit-commitment and dispatch process to gain additional unit-commitment flexibility. Currently, combined-cycle resources submit an economic minimum that reflects a multiple-turbine configuration. The ISO, with its current modeling capability, cannot commit alternate configurations. As a result, when reliability criteria require the out-of-merit commitment of a combined-cycle resource, more capacity may be committed than is actually needed. In the short run, the ISO is working toward alternate approaches that allow the commitment of combined-cycle resources below the economic minimum of the full combined-cycle configuration when the unit is required to meet local contingency needs. The goal is to better match the energy committed against the energy required, thereby minimizing reliability costs and the downward impact on prices. In the long run, the ISO believes that introducing a mixed-integer-programming technique will provide increased modeling flexibility that permits multiple combined-cycle configurations. The project will also improve the modeling of combined cycles in the dispatch software to reduce the total megawatts committed for reliability reasons.

Additionally, the project will review pricing rules and operating procedures to ensure they are consistent with each other and there are no barriers to the proper pricing or efficient use of resources. The ISO is investigating another market enhancement to capture out-of-merit dispatch costs in real-time reserve prices. Section 7.3 discusses this further.

Section 7

Research and Development

Several emerging areas of technology may offer benefits to the New England wholesale electricity markets. Prior to implementing any of these new technologies, however, the ISO must conduct research into their applicability to the New England marketplace. Starting with last year's plan, the ISO began providing information regarding such areas of research. Section 7 discusses ISO's present research and development projects.

The *2005 Wholesale Markets Plan* identified increased demand participation in markets, FTR options, and market simulator and unit-commitment enhancements as research topics. The ISO has made significant progress in increasing demand participation in markets, which has progressed to a defined project in this year's plan.

7.1 Market Simulator

The size of the New England wholesale electricity market and its impact on the New England economy require careful analysis before new initiatives are implemented. In the past, ISO New England examined the market impacts with the assistance of participants and outside experts in market design. The ISO is in the process of adding market simulation to the review process. Simulation will allow the ISO to provide, for example, better numerical estimates of an initiative's market efficiency gains.

The ISO and the Electric Power Research Institute (EPRI) are currently prototyping a market simulator to evaluate new market rules and infrastructure changes. The market simulator focuses on identifying market design incentives that might lead to inefficient results and will be able to estimate, for example, profit-maximizing supply offers in an import-constrained area.

The current version of the simulator being developed is evaluating the market reforms proposed for ASM Phase 2. Thus, it includes the modeling and estimation of optimal bidding for energy, a real-time reserve market, and a forward-reserve market.

ISO New England will evaluate the current simulator and alternative models as part of an ongoing plan to better evaluate new market designs and other initiatives.

7.2 Unit-Commitment Enhancements

Security-constrained unit commitment (SCUC) determines which resources to commit ahead of real time to optimally meet anticipated loads subject to known and probabilistic resource availabilities and constraints on the transmission system. Accordingly, SCUC plays an extremely important role in daily market operations. It not only influences the day-ahead market clearing, but it also affects the efficiency of real-time operation. Therefore, using an improved optimization technique in daily ISO market operations could result in substantial savings, improve overall market efficiency, and reduce total power costs borne by consumers.

Fortunately, the technology and methodologies associated with optimization algorithms are constantly evolving. The unit-commitment technique based on mixed-integer programming (MIP) has improved dramatically over the past few years, and production-level MIP programs have become feasible. MIP is well suited to address the unit-commitment problem and may even find the global optimal solution. The time needed to clear the day-ahead markets can be expected to decrease with the application of the MIP technique.

ISO New England has begun working with industry experts to explore the MIP capability for unit commitment. It will evaluate security-constrained unit-commitment engines from different vendors using both typical scenarios and day-ahead market production cases. The ISO has defined benchmark cases it will use to compare the MIP implementations of different vendors. These benchmark cases will also be used for comparison with the current implementation of the day-ahead market.

The ISO will also evaluate MIP's modeling capability on such resources as combined-cycle units and pumped-storage units, recognizing that improved combined-cycle modeling will enhance market efficiency by allowing the resources to bid in multiple configurations.

In addition, the ISO is working with its peers and the industry to develop a standard SCUC data interface. This interface, if developed and adopted by major SCUC vendors, will move the industry toward systems that are more open and, consequently, the capability of using the best-of-the-breed engines.

7.3 Improved Market Pricing to Reflect Out-Of-Merit Dispatch Costs

As discussed in Section 6.4, the current pricing design for the energy market does not explicitly model out-of-merit dispatch costs. Fully including the out-of-merit commitment and dispatch costs in energy or reserve pricing is an industrywide problem that has not been resolved. Capturing such costs in energy and reserve pricing would enable market participants to formulate financial hedges against such costs. It also would give resource providers price signals that would likely result in providing energy and reserve products more efficiently, which would lower overall electricity costs. The ISO is evaluating how to capture out-of-merit dispatch costs in real-time reserve prices.

Costs currently associated with out-of-merit commitment to maintain power system reliability criteria (i.e., second-contingency coverage) are not reflected in energy or reserve prices. To address this problem, the ISO is investigating a market-pricing enhancement that would set a local 30-minute reserve floor price based on the cost of the resource required to meet the local reserve requirement. The net result would increase both the local reserve and energy prices when the ISO commits resources out of merit to meet second-contingency requirements.

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