Standard Market Design
Implementation Report
March 1 through March 4

March 7, 2003
# Table of Contents

I. Executive Summary ................................................................. 2  
II. Analysis .......................................................................................... 5  
III. March 2003 FTR Auction Summary ........................................ 9  
IV. Market Monitoring ........................................................................ 10  
V. Day Ahead ..................................................................................... 11  
VI. Resource Adequacy Assessment (RAA) Process ..................... 14  
VII. Real Time Operations Summary ............................................... 16  
VIII. Information Technology ............................................................ 18  
IX. Northeast Pools Comparison ..................................................... 19  
X. Customer Issues ........................................................................ 21  

Appendix A - Day Ahead ................................................................. 1  
Appendix B - Real Time ................................................................. 15  
Appendix C - Comparison of Day Ahead to Real Time ................. 25  
Appendix D - InterRegional .......................................................... 35  
Appendix E - Day-Ahead and Real Time by Zone ....................... 51
I. Executive Summary

ISO-NE is pleased to report that the implementation of Standard Market Design (SMD) proceeded smoothly. In accordance with federal policy, SMD represents a major re-design of New England’s wholesale electricity marketplace and features two core components, locational marginal pricing (LMP) and a multi-settlement system for the energy market. This re-design benefits New England because it more accurately reflects the cost of wholesale power and provides guidance for infrastructure investment, including demand response, generation and transmission.

SMD addresses the flaws in the prior market caused by the use of a single uniform electricity price throughout New England. These flaws included the failure to send appropriate price signals to areas where electricity is more costly. This resulted in (i) consumers in low cost areas subsidizing higher cost areas and (ii) a lack of needed investment in those higher cost areas. Higher cost areas are generally those areas that experience congestion. Congestion reflects the higher cost of producing power within a region due to the inability to import lower cost power. SMD addresses this problem by distributing the costs of producing electricity more fairly and sending the appropriate price signal in the high cost area through the LMP pricing system.

In December 2002, ISO-NE intensified its extensive planning and preparation for the March 1 implementation of SMD. The ISO undertook more extensive market cutover communications with market participants in late January 2003 as the last of three external market trials was concluding. This communication fostered early involvement of market participants to address business and technical issues such as asset registration and connectivity issues. This extensive planning and preparation were the key factors to a successful and relatively smooth cutover.

Thus far, the electricity prices experienced in New England under SMD have been consistent with the cost of fuel and other wholesale electric markets in the Northeast. As in the other markets, the overall price levels have been affected by the dramatic increase in natural gas prices over the past month. During the week prior to SMD implementation, the price of natural gas increased more than 60 percent, jumping from $9.99/mmbtu to $16.15/mmbtu for day-ahead gas and even higher for intra-day gas supply. This increase in natural gas prices added volatility and caused a corresponding general increase in electricity prices for both the day-ahead and real-time electricity markets relative to the prices prior to SMD implementation.

In addition, the Real time market commitment process has been changed, requiring increased participation and decision-making by generators. While there has been participation via self-scheduling in Real Time, the ISO expects this will increase as participants become more familiar with SMD processes. The result is somewhat higher and more volatile Real Time prices during the learning process.
Early clearing prices for both the day-ahead and real-time energy markets indicate generally comparable prices across pricing zones in the region, with only small, sporadic price differences. The price differences in the real-time market were primarily due to differences in transmission losses among locations; very little was due to transmission congestion. In real-time, actual load levels have been consistent with the prior day forecast.

Overall, the day-ahead market has performed well. There has been some congestion in the day-ahead market, particularly in the first two days. This congestion has been due, at least in part, to the use of the virtual supply and demand features of the new SMD market, which help market participants hedge the risk of price volatility in the real-time market. Specifically, congestion has been caused by market participants’ use of virtual supply offers and virtual demand bids, in combination with high levels of fixed demand bids, which caused a number of binding constraints that resulted in congestion in the day-ahead market. At this time, it appears that the new day-ahead market is serving its intended purpose of offering a useful hedge for market participants to limit their exposure to price volatility.

Under the new market design, ISO-NE conducts a Resource Adequacy Assessment (RAA) that is performed each day to ensure that sufficient generation is committed and ready to operate to satisfy the forecast demand. On several occasions additional units were committed subsequent of the Day Ahead market through the RAA process, reflecting the difference between levels of generation cleared in the day-ahead market and the forecasted load levels. The level of incremental units scheduled for load and reserves ranged from 4400 MW on March 1, declining to about 2000 MW over the first four days of operation. Thus far, the RAA procedures have worked well with no significant issues to report.

The most significant reliability issue at present is the adequacy of natural gas supply for the region’s gas-fired generating units. This problem, which is unrelated to SMD but which occurred concurrently with the implementation of the new market, is affecting the entire Northeast.

The regulation market structure and software changed with the implementation of SMD (regulation is also known as AGC or automatic generation control and is used to ensure that electricity supply and demand are matched on a moment to moment basis). The new regulation mechanism has generally functioned well. ISO-NE is continuing to monitor regulation performance and CPS2 compliance and will consider whether additional tuning of the regulation algorithm is needed. CPS2 is a reliability criteria used to measure the performance of the New England power system. The power system’s performance is currently in excess of the NERC CPS2 criteria of 90%.

Prior to the implementation of the new energy market component of SMD, another separate feature of the market that helps market participants reduce their exposure to congestion in the day-ahead market was implemented. This feature involves the auctioning of Financial Transmission Rights (FTRs). The initial auction of FTRs for the March supply period was held in mid-February. The initial auction of monthly
FTRs provided an opportunity for market participants to gain experience and a better understanding of FTR value prior to participating in future auctions for longer-term FTRs. The initial FTR auction was successfully implemented with no major issues to report. A significant number of bids were received at relatively low dollar amounts. Increased participation is expected as historical data on locational prices becomes available, which will assist bidders in better assessing the value of FTRs.
II. Analysis

Fuel prices have been especially volatile during the first days of SMD implementation. Because of this volatility, it is difficult to make direct comparisons between prices under the interim market structure and under SMD because the major cost input has changed dramatically in price. The volatility of production costs, based on fuel prices, is shown in the figure below, along with the average daily electricity prices during the transition to SMD. Gas plant production costs are based on a baseload gas plant (approximately 7,000 heat rate), while oil production costs are based on an intermediate unit (approximately 10,000 heat rate). Both oil and gas prices have increased significantly since the first of the year.

![Graph](image-url)

1 Graph revised 3/17/03 to correct title and to expand graph to show previously missing higher price data points.
Proportion of Generation by Fuel Type

The following figure shows the shift away from gas-fired generation to other fuel types over the last weeks. The proportion of MW generated by gas fired generation (in hour-ending 14) has fallen to approximately 20% over that time. Oil and oil/gas fired generation has increased.

Virtual Trading Volumes

Virtual trades (virtual supply and virtual demand) were highest in volume on the first day of the SMD, with approximately 210,000 MWs of virtual supply and virtual demand submitted for the day. About 90,000 MWs cleared. Beginning on the second day, the volume of virtual demand fell to about half the initial volume, while virtual supply fell to about one-quarter of their initial volume. They stayed in approximately this range for the next four days. Total demand, both fixed and price sensitive, stayed roughly constant over the first days.
Hub Stability

With the exception of the first day, virtual supply and virtual demand at the hub have not experienced large imbalances. The imbalances experienced on the first day are primarily the result of an acknowledged submittal error by a participant. There has not yet been significant congestion at the hub in the Day Ahead market.
III. March 2003 FTR Auction Summary

The entire capacity of the NEPOOL transmission system was made available for the month of March 2003, the first New England FTR Auction under SMD. Since this was the initial monthly auction and the longer-term auctions are not contemplated until later in the year, there was only “buy” activity. Twenty-nine bidders participated in the auction. Two of those entities failed the Financial Assurance test and their bids were withdrawn from the Auction in accordance with established procedures.

A total of 711 bids for FTRs totaling over 28,000 MW and $4,839,000 were submitted by the remaining 27 entities. FTRs totaling nearly 18,000 MW cleared the auctions at a total of over $1 million. These results also included a small number of FTRs that cleared with negative values. The On-Peak, Off-Peak and total bids and awards are summarized below.

<table>
<thead>
<tr>
<th>MAR 2003 FTR Auction Results Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>FTR Bids Submitted</strong></td>
</tr>
<tr>
<td><strong>Bid Count</strong></td>
</tr>
<tr>
<td><strong>Buy/Sell</strong></td>
</tr>
<tr>
<td>Buy</td>
</tr>
<tr>
<td>Buy</td>
</tr>
<tr>
<td>Buy Total</td>
</tr>
<tr>
<td>Grand Total</td>
</tr>
</tbody>
</table>

| **FTR Bids Cleared**                |
| **Buy/Sell**                        | **Class Type** | **Award MW** | **Award Dollars** | **Cleared Bids** |
| Buy                                 | Off-Peak       | 7,145.8     | $ 48,231.62 | 180 |
| Buy                                 | On-Peak        | 10,761.9    | $ 1,007,040.09 | 347 |
| Buy Total                           | 17,907.7       | $ 1,055,271.71 | 527 |
| Grand Total                         | 17,907.7       | $ 1,055,271.71 | 527 |

There were no problems encountered in conducting the auction, other than some initial connectivity problems for a few participants that were readily remedied. After the awards were posted, there was an apparently isolated issue in which one entity informed ISO-NE they had structured their bids incorrectly and asked how they could secure the FTRs that they had hoped to be awarded in the auction. They were advised that they could do so on the secondary market. All the information needed to do so is available both on eFTR and the ISO-NE public web site.
IV. Market Monitoring

The Market Monitoring and Mitigation department (MMM) supported Day Ahead and Real Time markets by evaluating the need for mitigation, monitoring participant behavior, and contacting participants about anomalous behavior.

Over the first four days of operation under SMD, MMM detected no abnormal behavior that disrupted market clearing. There was no significant level of transmission congestion in real time in any of the days. While there was congestion in the Day Ahead market, it was caused by virtual bids not subject to mitigation. The virtual bids were evaluated by MMM and were either the result of participant submittal error or attempts to execute a Seller’s Choice transaction. Neither pattern was repeated in the initial four day period. Units submitting offers were generally within mitigation behavioral limits. As a result no mitigation was necessary.

MMM software has been in-place and executed. No software problems were found. In addition to automated software screens, MMM has performed extensive manual reviews of submitted data.
V. Day Ahead

Clearing the first day of the Day Ahead Markets under Standard Market Design (SMD) progressed very smoothly and resulted in the Day Ahead Market schedule being published to the market on time at 16:00. On days two and three the bidding and evaluation process were also conducted without experiencing major problems and operated as intended. On each of those days, ISO-NE was slightly delayed in publishing and after carrying out procedures associated with enforcing Financial Assurance and fixed Demand Bidding requirements. The fourth day again progressed well with results being published on time.

With the exception of a problem that was identified related to the calculation of losses on non-Pool Transmission Facilities (PTF), only minor issues were found. Loss factors used in the Day Ahead Market for non-PTF transmission facilities were not correct in the first days of the application. While the SMD systems produce correct data beginning with the first day of the new markets for both the Day Ahead and Real Time Markets, the loss factors used in the Day Ahead market are based on a rolling 7-day average. Incorrect non-PTF facility loss data for the days prior to the start of SMD were used in the rolling average causing incorrect results in this initial period. This has since been remedied and appropriate adjustments to calculated losses will be made along with corresponding billing adjustments.
The two following graphs show hourly Day Ahead LMPs at the hub, load zones, and external nodes.

March 1-4, 2003 DA LMPs for Hub and Load Zones

March 1-4, 2003 DA LMPs for Hub and External Nodes
The graph below shows cleared Demand and virtual demand bids and virtual supply offers. The steadily increasing virtual supply offers on March 1 were the result of a participant submission. The participant subsequently advised ISO that the submission was unintended due to an error in their software system. This error has not been repeated.
VI. Resource Adequacy Assessment (RAA) Process

Reserve Adequacy Analysis (RAA) is performed by the ISO-NE Forecasting Department each day after the close of the Real Time Energy Market Re-offer Period. The RAA process includes the updated Supply offers from the re-offer period, updated unit availability information, and updated ISO load forecast information including deviation between the ISO load forecast and the sum of cleared demand bids and decrements bids used in the Day Ahead market commitment. The focus of the RAA is reliability and the objective is to minimize the capacity costs associated with any additional capacity that may be required. Capacity must be sufficient to satisfy the ISO load forecast, Operating Reserve requirements, the Replacement Reserve requirement, and the Regulation requirement. The NEPOOL Market Operations Manual (Manual M-11) provides additional detail about the RAA process.

The RAA process for March 1 through 4 went smoothly. Details about generation quantities committed during the RAA process for the peak load hour each day are provided below.

March 1: The forecast load for March 1, hour ending 19, was 16,700 MW. Total demand cleared day ahead was 17,047 MW\(^2\). Cleared virtual supply offers totaled 4,827 MW, with a total of 12,220 MW of actual generation (supply offers) cleared day ahead.

During the initial RAA process for March 1, an additional 3883 MW of generation was scheduled for the forecast peak hour relative to what cleared in Day Ahead. This included 971 MW that was self-scheduled and 65 MW that was scheduled in Day Ahead and de-committed in Real Time.

March 2: The forecast load for March 2, hour ending 19, was 16,525 MW. Total demand cleared day ahead was 14,825. Cleared virtual supply offers totaled 211 MW, with a total of 14,614 MW of actual generation (supply offers) cleared day ahead.

During the initial RAA process for March 2, an additional 1552 MW of generation was scheduled relative to what cleared in Day Ahead. This included 700 MW that was self-scheduled and 50 MW that was scheduled Day Ahead and de-committed in Real Time.

March 3: The forecast load for March 3, hour ending 19, was 20,625 MW. Total demand cleared day ahead was 17,845. Cleared virtual supply offers totaled 777 MW, with a total of 17,068 MW of actual generation (supply offers) cleared day ahead.

During the initial RAA process for March 3, an additional 1,982 of generation was scheduled for the forecast peak hour of the day relative to what cleared in Day Ahead. This included 491 MW that was self-scheduled. No generation scheduled Day Ahead was de-committed in Real Time.

---

\(^2\) Total demand is the sum of cleared Price Sensitive Demand Bids, cleared Fixed Demand Bids, and cleared Decrement Bids.
March 4: The forecast load for March 4, hour ending 19, was 19,250 MW. Total demand cleared day ahead was 17,741. Cleared virtual supply offers totaled 504 MW, with a total of 17,237 MW of actual generation (supply offers) cleared day ahead.

During the initial RAA process for March 4, an additional 1,954 MW of generation was scheduled for the forecast peak hour of the day relative to what cleared in Day Ahead. This included 718 MW that was self-scheduled. No generation scheduled Day Ahead was de-committed in Real Time.

The graph below shows Day Ahead demand and cleared MWs, forecast load, and actual load. Actual load tracked forecast load very closely, and the shortfall of Day Ahead MWs is apparent.
VII. Real Time Operations Summary

There were no constraints activated during Real Time operation on any of the first 3 days of SMD. Therefore, there was no congestion price separation in the Real Time LMPs for during this period. On March 4 constraints were activated during real time operation as follows:

- Maine was export constrained for some intervals during hours ending 12, 13 and 23.
- Southwest CT was import constrained during hour ending 18:00.
- NEMA Boston interface was import constrained during hour ending 19.

The Real Time desired dispatch points (DDPs) and LMPs were correctly calculated during these periods and were fully consistent with the results expected under locational marginal pricing and dispatch. On day four an operator error resulted in a disruption in the operation of the LMP calculator for slightly more than an hour. This affected prices in two hours. The hourly LMPs were produced from available data. However, there is not a means to disaggregate the results to individual price nodes in that circumstance.

There were initial questions from some participants with respect to the procedures that they needed to follow to commit their resources for energy in response to locational prices. ISO-NE explained the procedures to those Participants and economic response of resources improved over the first four days.

ISO-NE has identified an issue with the real-time dispatch of generation. Occasionally, units are sent desired dispatch points (DDPs) above or below their "ecomax" or "ecomin" limits because the real-time dispatch software does not constrain the dispatch to the operating limits if the generator’s actual output is not within the operating limits. ISO-NE has developed an interim plan for handling this problem, and is working on a permanent solution. A detailed explanation of this issue is available on the ISO-NE web site at: <http://www.iso-ne.com/ISO_Customer_Services/State_Estimator.pdf>.
The following two graphs show hourly RT LMPs at the hub, load zones and external nodes.

March 1-4, 2003 RT LMPs for Hub and Load Zones

March 1-4, 2003 RT LMPs for Hub and External Nodes
VIII. Information Technology

Preparations Prior to March 1

From an Information Technology (IT) perspective, the implementation of SMD went well. Extensive preparation and planning was undertaken to ensure success.

Some of the key events leading up to March 1st included:

- External and Internal market trials in September 2002, November 2002, and January 2003. (The same systems used for Market Trials were placed into service March 1, reducing the risks of SMD implementation.)
- FTR and Outage Scheduler access starting January 27, 2003
- EMarket and EES access starting February 19, 2003
- Parallel run of day ahead and real-time systems starting February 24, 2003

These events were accomplished in accordance with the schedule and without significant problems.

Cutover Period (February 28 - March 1)

To ensure a smoother cutover, Day-ahead, Forecast and Operations activities began 5 days prior to March 1. Other business functions (i.e. Market Monitoring and Mitigation) began within that week to also flush out any startup issues prior to March 1. During this same period, actual telemetry fed the new SMD systems to allow a full complement of Operators to operate the SMD systems 7/24 starting on January 24. This allowed for pre-March 1 dry runs of business process, system executions and complete execution of the extensive data bridges used in the SMD implementation.

There were no hardware outages or software failures during the cutover period. IT staff were on-site throughout the weekend and assisted in answering questions, monitoring systems, and ensuring a smooth transition. All SMD systems were performing normally and the cutover period was completed as of March 1, 2003 @ 0300.

It is worth noting that ISO-NE upgraded not only its Market System but also its Energy Management System during the cutover.

100-Hour Stability Period (March 1 0300 – March 5 0700)

The IT systems have operated very reliably. Issues that were identified during the 100-hour stability period were prioritized and IT responded very quickly (i.e. within hours) to resolve high priority issues. Overall system reliability achieved during the 100-hour stability period was 99.9+%. 
IX. Northeast Pools Comparison

The two graphs below show the energy component of the LMP in New England, New York and PJM. The reader can observe that while prices in the three pools follow the same general trend, especially in Day Ahead, there are considerable differences between the Real Time prices in most hours.
New England, New York, and PJM RT Energy Component
March 1-4, 2003

Date

01MAR03:00:00  02MAR03:00:00  03MAR03:00:00  04MAR03:00:00  05MAR03:00:00

$/MW

$0  $100  $200  $300  $400  $500

PJM RT Energy  New York RT Energy  New England RT Energy
X. Customer Issues

The Customer Service and Training department was extremely busy for the last day of bidding on Friday, February 28, logging in 97 tickets. Monday, March 3 and Tuesday, March 4 were also very busy with 94 and 88 tickets, respectively. During that time, backlog in answering customer inquiries rose with 57 tickets open at the close of business on March 4. However, the oldest open ticket was two days old with inquiries being answered at a rapid pace.

Open Customer Issues:

Several participants have requested better access to data, such as LMP and load data, via the ISO web site. They are still learning where on the web data is available, and would like the data to be more user-friendly.

Traders have expressed a need to know which nodes are PTF. This issue is important to entities with seller’s choice contracts, which typically must be delivered at PTF nodes. Buyers and sellers have had disputes about which nodes are PTF. The TSO department is working to develop a list of PTF nodes that will be posted on the ISO web for participants’ reference.

Customer Education Issues:

The Customer Service and Operations Analysis departments have responded to numerous participant questions. Many participants have asked for more information about how their generating units are being dispatched. Some of their questions suggest that some participants are still in the learning process on the new bidding concepts and procedures.
For example, some participants have indicated that they had expected ISO-Ne to give them dispatch orders based on their units’ energy offers in real time, even though the non-quick start units had not been committed for capacity day ahead or during the RAA process. These participants did not understand that they were responsible for determining whether their units were in merit and then self-scheduling the units.

Under the new SMD market procedures, external transactions from NY to NE have to be cleared in the NY day-ahead market to be eligible for ICAP credit in NE. One Participant offered in such a way for the first day of SMD that the transaction did not clear in the NY day-ahead market. ISO-NE disallowed the transaction per its procedures.

Some participants made errors in submitting bids. Examples include:

- A participant erred by virtual supply offers and virtual demand bids (Incs and Decs) that increased by a fixed amount each hour of the day. These were detected but cleared as submitted and contributed to congestion in Connecticut in the Day Ahead market for March 1. The error was due to a problem with the participant’s trading software.

- A participant submitted load in Maine greater than their expected Real-Time load obligation in that zone. While the submitted load did not exceed interim screens because the Participant’s aggregate bids were not significantly over expected total real time load, the bid likely would have exceeded long term screens that will apply once historical data for locational loads under SMD become available. The participant was contacted in accordance with established procedures and voluntarily changed Day Ahead demand bids prior to the deadline for submitting bids.

- A participant submitted load intended for New Hampshire into Connecticut. However, the load did not exceed the interim screen because the participant’s total load was not significantly over its expected real time load obligation. The submitted load would have exceeded long term screens. The issue was detected and the participant was contacted by ISO-NE after Day Ahead market clearing. This did not prevent normal clearing of the market.

- Other participants were contacted to deal with miscellaneous issues including non-dispatchable units offered as dispatchable Day Ahead, units failing to offer economic min at true low operating limits, and units out-of-service offered as available day-ahead. It is expected that incidents such as these will decline as participants become more knowledgeable of detail bidding requirements under SMD rules and procedures.
Software Issues

The process of automated retrieval and confirmation of Internal Bi-lateral Contracts (IBT’s) in the Settlements Market System had slow performance March 1. This was impacting usability and preventing confirmation of contracts in some cases. Performance of the software was improved on March 2 and additional improvements associated with IBT systems were implemented later in the week.