SCHIFF HARDIN LLP

Sherry A. Quirk
202/778-6475
squirk@schiffhardin.com

October 1, 2007

Via Hand Delivery

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *ISO New England Inc. and New England Power Pool*, Docket No. ER06-613-___-- Compliance Report of ISO New England Inc. Regarding Performance of Reserve Markets

Dear Secretary Bose:

Pursuant to the Federal Energy Regulatory Commission's ("Commission") order issued on May 12, 2006 in the above referenced proceeding,[1] ISO New England Inc. (the "ISO") hereby submits a report on the status of the implementation of certain reserve market changes that were included as part of Phase II of the Ancillary Services Market ("ASM") project.[2] In the May 12 Order, the Commission directed the ISO to file semi-annual reports on the reserve market changes. This filing is the third reserve market compliance report.[3] The ISO is submitting an original and 14 copies of this filing.

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[1] *New England Power Pool and ISO New England Inc.*, Order Accepting Ancillary Services Market Proposal, 115 FERC ¶ 61,175, *order denying rehearing*, 117 FERC ¶ 61,106 (2006) ("May 12 Order").

[2] Capitalized terms used but not otherwise defined in this filing have the meanings ascribed thereto in the ISO's Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3, (the "Tariff"), the Second Restated New England Power Pool Agreement and the Participants Agreement.

[3] The first semi-annual compliance report was submitted on November 13, 2006. Compliance Report of ISO New England Inc., *New England Power Pool and ISO New England Inc.* (filed Nov. 13, 2006) ("November 13 Compliance Report"). Because the new locational forward reserve market and the new real-time reserve market began operating on October 1, 2006, the ISO indicated in its November 13 Compliance Report that the ISO would be filing a report on the first six months of its operations on April 1, 2007. November 13 Compliance Report at 2. The ISO filed the second semi-annual compliance report on April 2 (the first business day following April 1) ("April 2 Compliance Report"). The ISO requested

I. BACKGROUND

The May 12 Order required the ISO to report semi-annually on various issues related to the implementation of certain reserve markets. Specifically, the Commission directed the ISO to:

> file a report semi-annually on the performance of the new market, including recommendations for future improvements. In addition, . . . these reports should provide: (1) updates on the implementation of a forward TMSR [Ten-Minute Spinning Reserves] market, including descriptions of proposals that have been considered to date, impediments to implementation that still need to be resolved, and a proposed schedule to resolve such impediments; (2) details concerning ISO-New England's operational and economic rationale for considering involuntary load shedding in determining reserve requirements in NEMA/Boston and the effect on reliability of considering voluntary load shedding; (3) once ASM Phase II has been operational for at least six months, a summary on whether increased failure-to-reserve and failure-to-activate penalties have successfully created an incentive for sellers to include commitment costs in their forward reserve bids (allowing ISO-New England to select the lowest-cost resources to provide reserves); and (4) a discussion concerning whether allowing forward reserve suppliers to buy back their obligations in a future day-ahead spot market would promote or impede the objectives of (i) encouraging sellers to include their full costs (including commitment costs) in their forward reserve bids, and (ii) procuring the lowest-cost resources to provide reserves.[4]

The May 12 Order required that the first report be filed six months from the date of the issuance of the order, with each subsequent report due every six months.[5] The first compliance report was submitted on November 13, 2006 and the second compliance report was submitted on April 2, 2007.

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in the November 13 Compliance Report that the due date for subsequent semi-annual reports be based on the April 1, 2007 date, rather than the date required by Ordering Paragraph B of the May 12 Order. Thus, as indicated in the ISO's November 13 Compliance Report, unless otherwise directed by the Commission, the ISO files the instant and will file reports subsequent to the instant report on April 1, 2008, October 1, 2008, etc. November 13 Compliance Report at 2.

[4] May 12 Order at P 110 (footnotes omitted).

[5] May 12 Order, Ordering Paragraph (B).

The ISO has prepared a report on the status of New England's reserve markets, which includes information relevant to the Commission's inquiries.[6] The Reserve Markets Report, a copy of which is attached hereto, focuses on analyses and summaries of the new reserve markets. Aspects of the Reserve Markets Report are discussed in more detail below.

II. REPORT

The instant filing responds to the Commission's directive, set forth in the May 12 Order, that the ISO provide semi-annual reports on issues related to implementation of the reserve market changes implemented on October 1, 2006. The following areas are addressed in this report:

1. Performance of the new forward and real-time reserve markets;

2. Evaluation of real-time reserve pricing;

3. Analysis of settlement results based on forward and real-time reserve payments and failure-to-reserve penalties; and

4. The incorporation of expectations regarding failure-to-reserve and failure-to-activate penalties in forward reserve supply offers.

While the operations of the new locational forward reserve market (the "Forward Reserve Market") and the new real-time reserve market have provided a basis for the ISO to supply informed responses to the Commission's inquiries, as of the filing date, the new reserve markets have been in place for only twelve months. As the reserve markets mature, the ISO will be able to perform more comprehensive analyses, based on additional months of operational experience. The results of those analyses will be discussed in future ISO reports.

A. Overall Performance of the Reserve Markets

As indicated above, the Commission in its May 12 Order directed the ISO to file a report "on the performance of the new market, including recommendations for future improvements."[7] The new locational forward reserve market and the new real-time reserve market began operating on October 1, 2006. The statistical analysis upon which the instant Reserve Markets

[6] ISO New England Inc. – Market Monitoring, *A Report on Operation of the New England Reserve Markets*, October 1, 2007 ("Reserve Markets Report") (see attached).

[7] May 12 Order at P 110.

Report is based reflects historical data from February 1, 2007 through August 31, 2007 (the "Reporting Period").[8]

As indicated in the Reserve Markets Report, the Forward Reserve Market and real-time reserve pricing mechanism generally performed as expected during the Reporting Period. The information in the Reserve Markets Report will form the basis of continued monitoring and analysis, as the ISO, market participants and other stakeholders gain more experience with the market changes over various operating seasons and conditions.

1. Summary of Market Performance

Based on information from the Reporting Period, the ISO's analysis reveals that both real-time reserve pricing and the Forward Reserve Market have generally performed as designed.[9] Based on the analysis, seven main observations and conclusions can be made. First, two Forward Reserve Auctions were held during the Reporting Period, for the Summer 2007 and Winter 2007/2008 periods. Rest-of-System Ten-Minute Non-Spinning Reserve ("TMNSR") clearing prices were $10,800/MW-month and $9,050/MW-month in these auctions, representing a significant increase from the clearing price of $4,200/MW-month in the first locational auction.

Second, Forward Reserve Market requirements were not met in either auction for Thirty-Minute Operating Reserves ("TMOR") in the Connecticut ("CT") and Southwest Connecticut ("SWCT") reserve zones, causing the clearing price to be set at the cap of $14,000/MW-month. The Northeast Massachusetts ("NEMA") reserve zone also fell short of requirements and cleared at the cap in the Summer 2007 auction. Transmission improvements that lowered the requirement for the Winter 2007/2008 auction have resulted in requirements being met and a clearing price of $8,500/MW-month for NEMA TMOR.

Third, non-zero real-time reserve prices occurred infrequently during the Reporting Period. There were positive hourly reserve prices in less than 3% of hours in the Rest-of-System and NEMA reserve zones, and less than 5% of hours in the CT and SWCT reserve zones. Positive reserve prices occurred when capacity conditions were tight due to generator or transmission line outages or high loads.

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[8] The previous reserve market compliance report, filed on April 2, 2007, reflected historical data from October 1, 2006 to January 31, 2007.

[9] The Reserve Markets Report is based primarily on the ISO's analysis of reserve requirements, reserve clearing prices, corresponding power system conditions and settlement data.

Fourth, when TMOR prices in the CT and SWCT reserve zones were positive, economic redispatch of generation for reserves was often insufficient to meet reserve requirements. In order to maintain reserves in CT, ISO operators often had to take additional action, binding the proxy transmission interface limit to create more import reserve capacity on about one-half of the days with positive reserve prices in CT.

Fifth, Net Commitment Period Compensation ("NCPC") payments made to generators committed for reliability in the NEMA and CT load zones declined slightly after the implementation of the locational component of the Forward Reserve Market. Several generators that were committed for reliability and received NCPC payments for local second contingency protection during October 2005 to September 2006 were designated as forward reserve resources after October 2006, and thus no longer had to be committed by the ISO. Most of these were generators that had been committed for reliability infrequently and received small amounts of NCPC.

Sixth, the ISO continued its program to monitor and adjust CLAIM10 and CLAIM30 values in conjunction with the new reserve markets.[10] The failure to perform either during normal operations or during audits results in an adjustment to the megawatt value of reserve credit allowed to the failing resource. The auditing program is effective, identifying approximately 1,600 MW of non-performing resources with CLAIM10 reserve capability and 1,000 MW of non-performing resources with CLAIM30 reserve capability. Many of the generators that were eliminated from the pool of fast start generators are run-of-river hydropower facilities. The performance auditing program has pushed non-performing generators out of the reserve market. The result is that the generators that retained their fast start designations – those with verified CLAIM10 and CLAIM30 reserve capability – start up and perform reliably.

Seventh, payments for forward reserves were approximately $96 million during the Reporting Period, while failure-to-reserve penalties totaled $3.5 million and failure-to-activate penalties totaled $3,537. Payments to resources that provided real-time reserves were approximately $1.06 million.

[10] CLAIM10 and CLAIM30 values reflect the output level that a resource can reach within 10 and 30 minutes, respectively, after receiving a Dispatch Instruction.

2. Recommended Further Analyses

Due to limited operating experiences, in many cases there is insufficient data to reach firm conclusions on several points. In these cases, the ISO recommends further analyses in future reports on the reserve markets, including the following:

- Continued analysis of reserve zone TMOR shortage events when the Reserve Constraint Penalty Factor ("RCPF") sets the reserve zone TMOR price, to confirm that the RCPFs are appropriate and adequate.
- Future observation of reserve shortage events for system TMOR requirements to determine whether there is any need to add more segments to the system TMOR RCPF values.
- Continued analysis of the Demand Response Reserve Pilot Program to assess the feasibility of including small demand response resources in the reserve markets.

B. Forward Ten-Minute Spinning Reserve Market

The May 12 Order stated that the ISO's semi-annual reports should also include "updates on the implementation of a forward TMSR market, including descriptions of proposals that have been considered to date, impediments to implementation that still need to be resolved, and a proposed schedule to resolve such impediments."[11] As indicated in the ISO's November 13 Compliance Report, the locational forward reserve market design approved by the Commission in the May 12 Order did not include a forward spinning reserve market.[12] However, as explained in the second compliance report,[13] a Forward Ten-Minute Spinning Reserve Market Working Group ("FSR Working Group") of the NEPOOL Markets Committee was formed to address, in coordination with the ISO, certain issues with respect to FSR. The FSR Working Group's October 13, 2006 report to the Markets Committee was part of the ISO's first compliance report in this proceeding.[14] Consistent with the issues that the Commission directed the ISO to address

[11] May 12 Order at P 110.

[12] November 13 Compliance Report at 2.

[13] April 2 Compliance Report at 7.

[14] Errata Compliance Report Attachment of ISO New England, *ISO New England Inc. and New England Power Pool*, Docket No. ER06-613-002 (filed Nov. 14, 2006) (attaching Forward Ten-Minute Spinning Reserve Market Working Group Report dated October 13, 2006, hereinafter "FSR Working Group Report").

in its May 12 Order, the FSR Working Group Report described various FSR proposals, potential impediments to implementation, and provided a proposed schedule to resolve impediments.

At the FSR Working Group's last meeting on September 18, 2006, the ISO indicated that it would not in the immediate future be able to provide the level of review and analysis of the several proposals that had been presented to the group that the ISO believed necessary to enable recommendations to be formulated and presented to the Markets Committee. As detailed in the second compliance report,[15] the FSR Working Group suspended further efforts until such time as the ISO is able to commit the resources to provide a thorough review and critique of the design proposals. As the ISO explained in its prior compliance reports, and as remains true, the ISO's market design and development resources have been devoted to many high-priority commitments regarding major market design initiatives.[16] These initiatives include implementation of the Forward Capacity Market and Long Term Transmission Rights. The ISO has had no further discussions with the Markets Committee or the FSR Working Group since the prior compliance reports were filed.

C. Failure-to-Reserve and Failure-to-Activate Penalties

As explained in the Reserve Market Report, payments for forward reserves are reduced by any failure-to-reserve or failure-to-activate penalties. Penalties are assessed if a participant does not offer an available, forward-reserve-capable resource into the energy market at or above the threshold price, or if an assigned resource is not able to provide energy within 10 or 30 minutes if called on during real-time operations. Participants receive exceptions to the failure-to-reserve penalty for periods when the unavailability is due to scheduled annual maintenance. Failure-to-activate penalties are applied only when control room operators have approved a contingency unit-dispatch software case. Failure-to-reserve penalties for the Reporting Period totaled $3.5 million. A failure-to-activate penalty of $3,537 was paid in August 2007.

The Commission required that, after the new Forward Reserve Market "has been operational for at least six months," the ISO must also include in its semi-annual reports "a summary on whether increased failure-to-reserve and failure-to-active penalties have successfully created an incentive for sellers to include commitment costs in their forward reserve bids (allowing ISO-New England to select the lowest-cost resources to provide reserves)."[17] As explained in the Reserve Market Report, Forward Reserve Market penalties are intended to

[15] April 2 Compliance Report at 7.

[16] November 13 Compliance Report at 5.

[17] May 12 Order at P 110.

provide incentives for participants to make resources available for reserve. The penalties were not designed to encourage particular offer strategies.

III. CONCLUSION

The ISO hereby submits this report in compliance with the Commission's May 12 Order accepting the ISO's proposed reserve market changes. If you have any questions or need further information with respect to this filing, please contact James Douglass or Sherry Quirk at the telephone numbers below.

Please acknowledge receipt of the foregoing by date-stamping and returning to our messenger the enclosed extra two copies of this filing.

Respectfully submitted,

By: ______________________

James H. Douglass, Esq.
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
Tel: (413) 540-4559
Fax: (413) 535-4379
E-mail: jdouglass@iso-ne.com

By: ______________________

Sherry A. Quirk, Esq.
Robin E. Remis, Esq.
Schiff Hardin, LLP
1666 K St., NW, Ste. 300
Washington, D.C. 20006
Tel: (202) 778-6475
Fax: (202) 778-6460
E-mail: squirk@schiffhardin.com
rremis@schiffhardin.com

Attachment

cc : Official Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 1st day of October, 2007.

Sherry A. Quirk

ATTACHMENT

A Report on Operation of the New England Reserve Markets

ISO New England Inc.

Market Monitoring

October 1, 2007

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1 Introduction

Changes to include a locational component in the forward reserve market (the "Forward Reserve Market") and new real-time reserve pricing were placed in service on October 1, 2006.[1] These enhancements were designed to provide price signals that would encourage efficient provision of system and local operating reserves.

The most significant changes to the existing market structures were the addition of a locational component to the existing Forward Reserve Market and the co-optimized dispatching and pricing of energy and reserves in real time. The locational feature was introduced to encourage investment in fast start resources in import-constrained zones in order to reduce reliance on more costly and inflexible units to provide local area reliability. The Forward Reserve Market changes also give reserve providers flexibility to participate in the market on a portfolio basis.

Real-time reserve pricing uses a co-optimized real-time energy and reserve dispatch to meet both the energy and reserve needs of the system more efficiently. Co-optimization enables real-time energy and reserve prices to reflect actual power system operating conditions more accurately. The combination of the Forward Reserve Market and real-time reserve pricing provides the opportunity for suppliers to recover fixed and variable costs associated with providing reserves, leading toward more efficient resource allocation.

The forward and real-time reserve markets include three local reserve zones, *i.e.*, Northeastern Massachusetts/Boston (NEMA), Connecticut (CT), and Southwest Connecticut (SWCT), where zonal reserve requirements were added to reflect the need to protect against local second contingencies. Each reserve zone is associated with a defined closed power system interface which has limited import capability and has historically required the commitment of out-of-merit resources to manage the local operating requirements.

There are three reserve products, listed here in decreasing quality: Ten-Minute Spinning Reserves (TMSR), Ten-Minute Non-Spinning Reserves (TMNSR), and Thirty-Minute Operating Reserve (TMOR). Any excess in higher quality reserve products can substitute for lower quality reserve products; *i.e.*, TMSR can substitute for TMNSR and TMOR, and TMNSR can substitute for TMOR. The prices of these reserve products reflect their qualities and locations. Reserve clearing prices cascade up from the lowest quality product to the highest quality product; and the reserve clearing prices of reserve zones are not less than that of the corresponding parent zone for any given reserve product.

[1] Capitalized terms used but not otherwise defined in this report have the meanings ascribed thereto in the ISO's Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3, the Second Restated New England Power Pool Agreement and the Participants Agreement.

This report focuses on the performance of the locational Forward Reserve Market and real time reserve pricing, and is primarily based on the analysis of reserve requirements, forward reserve auction results, reserve clearing prices, corresponding power system conditions, and settlement data. The report is divided into three sections, covering the locational Forward Reserve Market, real-time reserve pricing, and the distribution of reserve payments through the settlement process.

The analysis in this report is based on the historical data from February 1, 2007 to August 31, 2007 (the Reporting Period). The second reserve market compliance report, filed on April 2, 2007, covered October 1, 2006 – January 31, 2007. Two Operating Procedure No. 4 (OP4 – Actions in a Capacity Deficiency) events occurred during the Reporting Period, on February 12, 2007 and August 2, 2007. This report includes analysis of market performance and system conditions surrounding the August 2 OP4 event. The February 12 event was covered in the second reserve market compliance report.

2 Summary of Results

The Forward Reserve Market and real-time reserve pricing generally performed as expected during the Reporting Period. The details are summarized as follows:

1. Two Forward Reserve Market auctions were held during the Reporting Period, for the Summer 2007 and Winter 2007/2008 periods. Rest-of-System TMNSR clearing prices were $10,800/MW-month and $9,050/MW-month in these auctions, representing a significant increase from the clearing price of $4,200/MW-month in the first locational auction.

2. Forward Reserve Market requirements were not met in either auction for TMOR in the CT and SWCT reserve zones, causing the clearing price to be set at the cap of $14,000/MW-month. The NEMA reserve zone also fell short of requirements and cleared at the cap in the Summer 2007 auction. Transmission improvements that lowered the requirement for the Winter 2007/2008 auction have resulted in requirements being met and a clearing price of $8,500/MW-month for NEMA TMOR.

3. Non-zero real-time reserve prices occurred infrequently during the Reporting Period. There were positive hourly reserve prices in less than 3% of hours in the Rest-of-System and NEMA reserve zones, and less than 5% of hours in the CT and SWCT reserve zones. Positive reserve prices occurred when capacity conditions were tight due to generator or transmission line outages or high loads.

4. When TMOR prices in the CT and SWCT reserve zones were positive, economic redispatch of generation for reserves was often insufficient to meet reserve requirements. In order to maintain reserves in CT, ISO operators often had to take additional action, binding the proxy transmission interface limit to create more import reserve capacity on about one-half of the days with positive reserve prices in CT.

5. An OP-4 event occurred on August 2, 2007 due to high demand combined with generator outages and reductions. The co-optimized dispatch of energy and reserves at the system level resulted in positive real time reserve clearing prices in five hours on August 2.

6. Net Commitment Period Compensation (NCPC) payments made to generators committed for reliability in the NEMA and CT load zones declined slightly after the implementation of the locational Forward Reserve Market. Several generators that were committed for reliability and received NCPC payments for providing local second contingency protection during October 2005 to September 2006 were designated as forward reserve resources after October 2006, and thus no longer had to be committed by the ISO. Most

of these were generators that had been committed for reliability infrequently and received small amounts of NCPC.

7. The ISO continued its program to monitor and adjust CLAIM10 and CLAIM30 values in conjunction with the new reserve markets. The failure to perform either during normal operations or during audits results in an adjustment to the megawatt value of reserve credit allowed to the failing resource. The auditing program is effective, identifying approximately 1,600 MW of non-performing resources with CLAIM10 reserve capability and 1,000 MW of non-performing resources with CLAIM30 reserve capability. Many of the generators that were eliminated from the pool of fast start generators are run-of-river hydropower facilities. The performance auditing program has pushed non-performing generators out of the reserve market. The result is that the generators that retained their fast start designations – those with verified CLAIM10 and CLAIM30 reserve capability – start up and perform reliably.

8. Payments for forward reserves were approximately $96 million during the Reporting Period, while failure-to-reserve penalties totaled $3.5 million and failure-to-activate penalties totaled $3,537. Payments to resources that provided real-time reserves were approximately $1.06 million.

9. The Demand Response Reserve Pilot Program continued enrolling resources and conducting test events during the Reporting Period. Resources were activated for reserves 21 times in each seasonal reserve period. Although the project is still in the early stages, the ISO is evaluating appropriate solutions associated with metering and telemetry costs and other implementation issues.

Due to limited operating experience, there is insufficient data to reach firm conclusions on some points. In these cases, the ISO recommends further analyses in future reports, including:

1. Continued analysis of reserve zone TMOR shortage events when the RCPF sets the reserve zone TMOR price, to confirm that the RCPFs are appropriate and adequate.

2. Future observation of reserve shortage events for system TMOR requirement to determine whether there is any need to add more segments to the system TMOR RCPF values.

3. Continued analysis of the Demand Response Reserve Pilot Program to assess the feasibility of including small demand response resources in the reserve markets.

3 Forward Reserve Market

3.1 Design Objectives and Main Features

The objective of the Forward Reserve Market is to provide the appropriate financial incentives to retain and expand the New England region's inventory of flexible, peaking resources. The main improvements that were incorporated into the new Forward Reserve Market implemented on October 1, 2006 include the following:

- Adding local reserve zones, in addition to the system reserve requirement, in order to reflect the locational value of reserves within sub-areas of the system;
- Support for portfolio offers and enabling bilateral trading;
- Improving performance monitoring and the performance penalty structure.

Under the enhanced Forward Reserve Market design, each seasonal forward reserve auction simultaneously clears offers for TMNSR and TMOR to meet the forward reserve requirements for the system and each local reserve zone.

Market participants that take on forward reserve obligations through the Forward Reserve Market may assign specific resources to meet their obligations at any time prior to the commencement of an Operating Day.

3.2 Results

3.2.1 Forward Reserve Market Auction Results

During the Reporting Period, forward reserve auctions were conducted in April 2007, for the Summer 2007 period; and in August 2007, for the Winter 2007/2008 period.

3.2.1.1 Forward Reserve Auction Requirements

The system-wide and local reserve requirements for the locational forward reserve auctions are shown in Table 1 and Table 2. The system reserve requirements were based on a first contingency of 1400 MW and a second contingency of 1400 MW in the summer auction, and a first contingency of 1700 MW and a second contingency of 1400 MW in the winter auction. NEMA reserve requirements were reduced from 1050 MW in the summer auction to 280 MW in the winter auction because of transmission improvements in the NEMA area.[2]

[2] The transmission improvements resulted from the new 3164 Cable (Stoughton – Hyde Park) and 3162 Cable (Stoughton-K_Street).

Table 1: Forward Reserve Requirements, Summer 2007 (June 1, 2007 – September 30, 2007)

Reserve Zone	Reserve Category	Local 2nd Contingency MW	External Reserve Support MW	Reserve Requirement MW
New England Control Area	TMNSR	N/A	N/A	700
New England Control Area	TMOR	N/A	N/A	700
Rest-of-System	TMNSR/TMOR	N/A	N/A	798
SWCT	TMOR	520	0	520
CT	TMOR	1155	100	1055
NEMA/Boston	TMOR	1200	150	1050

Table 2: Forward Reserve Requirements, Winter 2007/2008 (October 1, 2007 – May 31, 2008)

Reserve Zone	Reserve Category	Local 2nd Contingency MW	External Reserve Support MW	Reserve Requirement MW
New England Control Area	TMNSR	N/A	N/A	850
New England Control Area	TMOR	N/A	N/A	700
Rest-of-System	TMNSR/TMOR	N/A	N/A	798
SWCT	TMOR	611	0	611
CT	TMOR	1366	0	1366
NEMA/Boston	TMOR	1180	900	280

There is a Rest-of-System minimum purchase requirement in order to ensure the clearing of resources that are physically located outside of the local reserve zones. This minimum purchase requirement is set at 600 MW, multiplied by an R-Factor of 1.33, which results in a requirement of 798 MW. The Rest-of-System minimum purchase requirement reflects the operational necessity of ensuring that reserve resources are not over-concentrated in a local area.

3.2.1.2 Forward Reserve Auction Offers

All offers in the locational Forward Reserve Market are portfolio-based (*i.e.*, the offers are not required to be linked to a particular physical resource). Figure 3-1 through Figure 3-6 show supply curves for each reserve area and product. Notable trends shown in these figures are:

- In the Rest-of-System zone, the quantity of TMNSR offered increased, while TMOR decreased. The increase in quantity was due to both new entry and increases in offered quantity by existing market participants. Offered reserve capacity was well in excess of requirements.

- The TMNSR offer curve for the Rest-of-System zone shows that offer prices increased sharply from Winter 2006/2007 to Summer 2007. Prices declined in the Winter 2007/2008 auction, but were still well above prices in the earlier Winter 2006/2007 auction. Some participants increased offer prices for reserve capacity that had been offered into the previous auction. There was also new entry into the market with offer prices that were inframarginal.

- Connecticut and SWCT forward reserve requirements have not been met in any of the three auctions. In the Summer 2007 auction, SWCT offers came within 5 MW of the requirement. In the Winter 2007/2008 auction, however, offers in the SWCT area decreased by 191 MW, from 515 MW in the summer auction to 324 MW in the winter auction. The decrease in offered capacity was partly due to a participant that had previously offered in SWCT offering into Connecticut instead, and partly due to increases in offered quantity from other participants. This resulted in an increase in Connecticut offers from 210 MW to 625 MW.

- NEMA forward reserve requirements were met for the first time in the Winter 2007/2008 auction. This was due to a decrease in the requirement, rather than an increase in offered reserve.

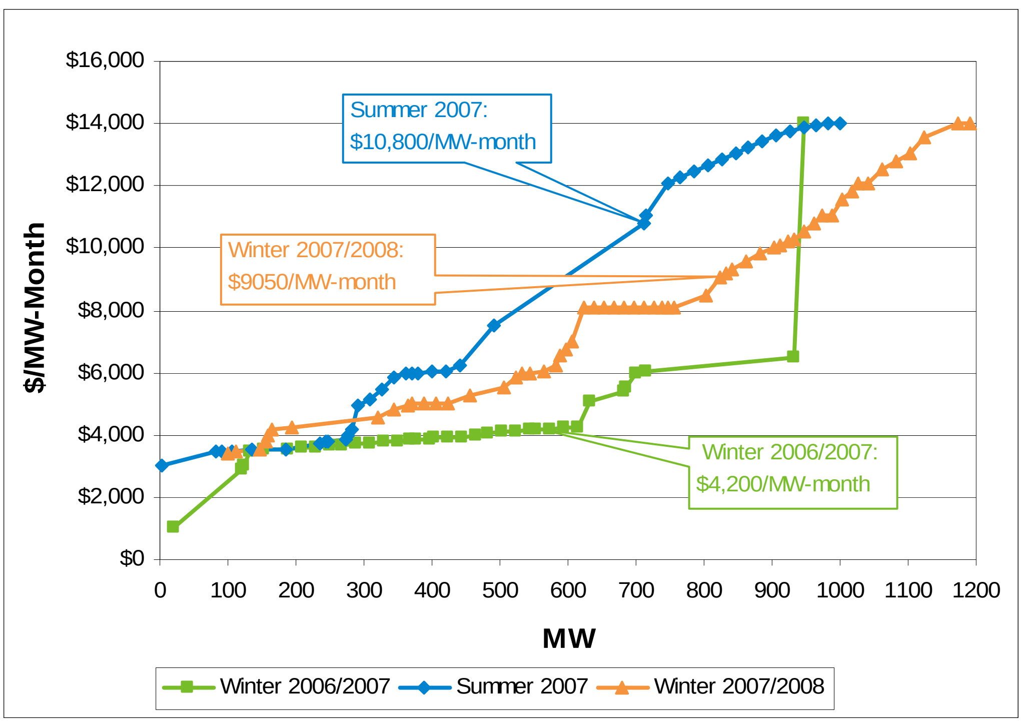

Figure 3-1: Rest-of-System TMNSR Offer Curves, Winter 2006/2007, Summer 2007, and Winter 2007/2008 Forward Reserve Auctions

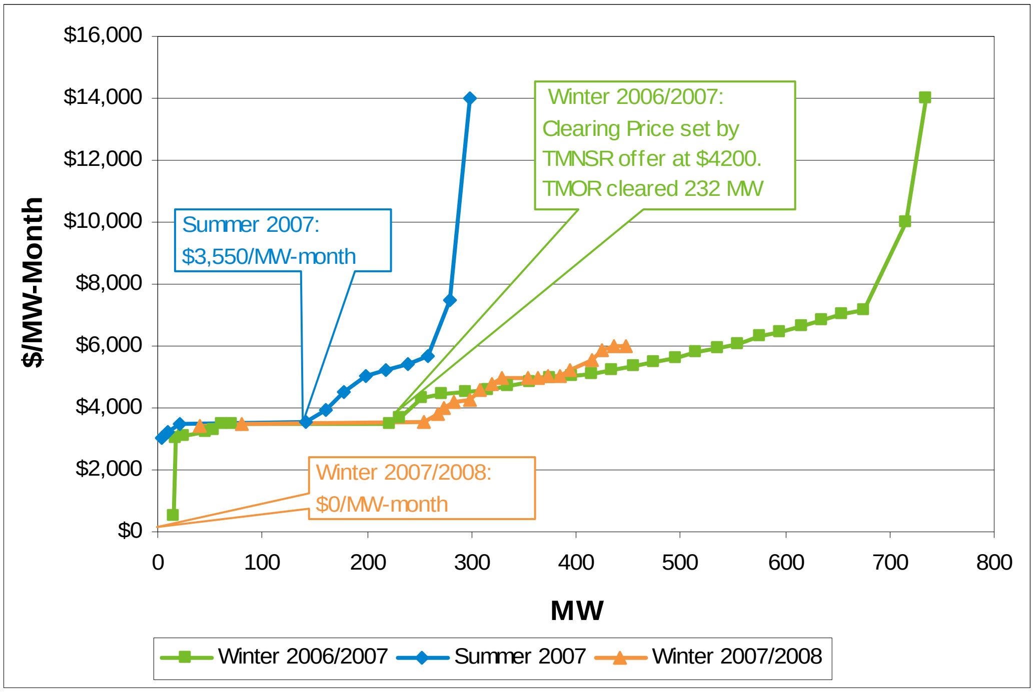

Figure 3-2: Rest-of-System TMOR Offer Curves, Winter 2006/2007, Summer 2007, and Winter 2007/2008 Forward Reserve Auctions

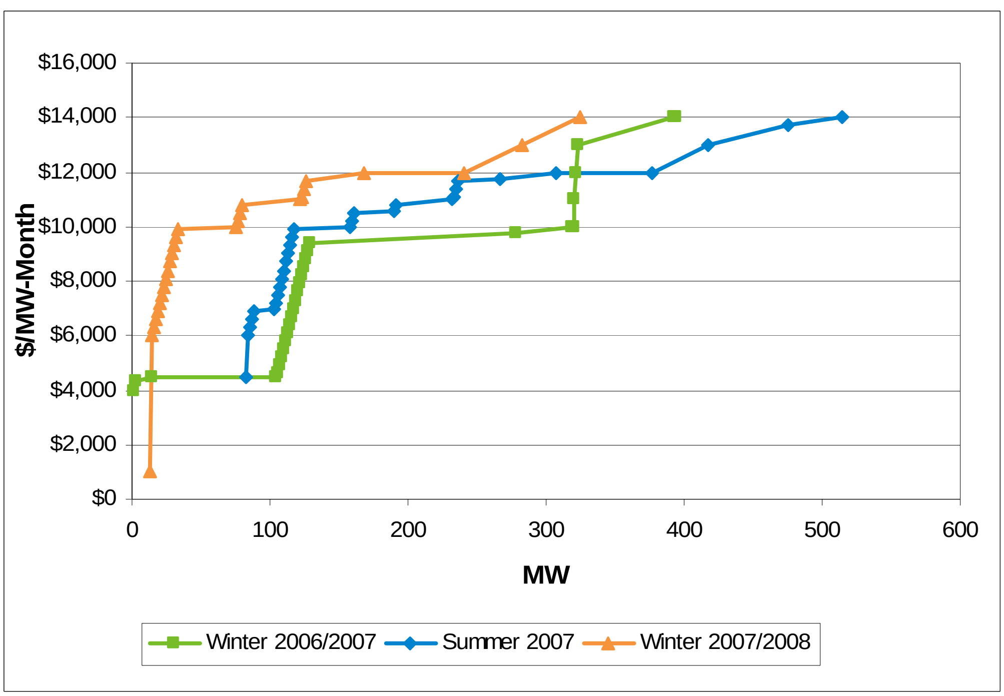

Figure 3-3: SWCT TMOR Offer Curves, Winter 2006/2007, Summer 2007, and Winter 2007/2008 Forward Reserve Auctions

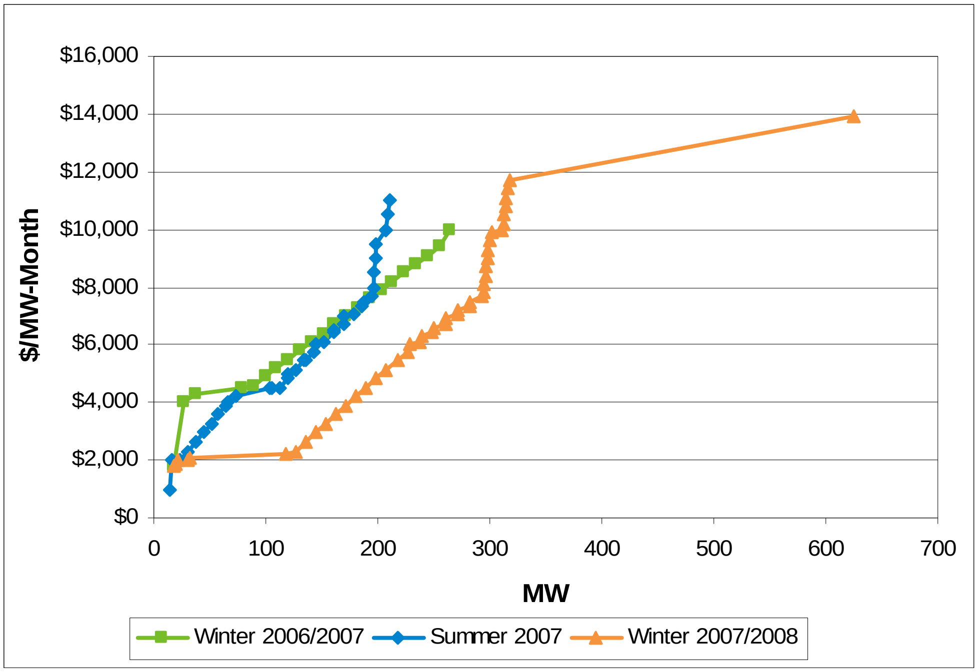

Figure 3-4: CT TMOR Offer Curves, Winter 2006/2007, Summer 2007, and Winter 2007/2008 Forward Reserve Auctions

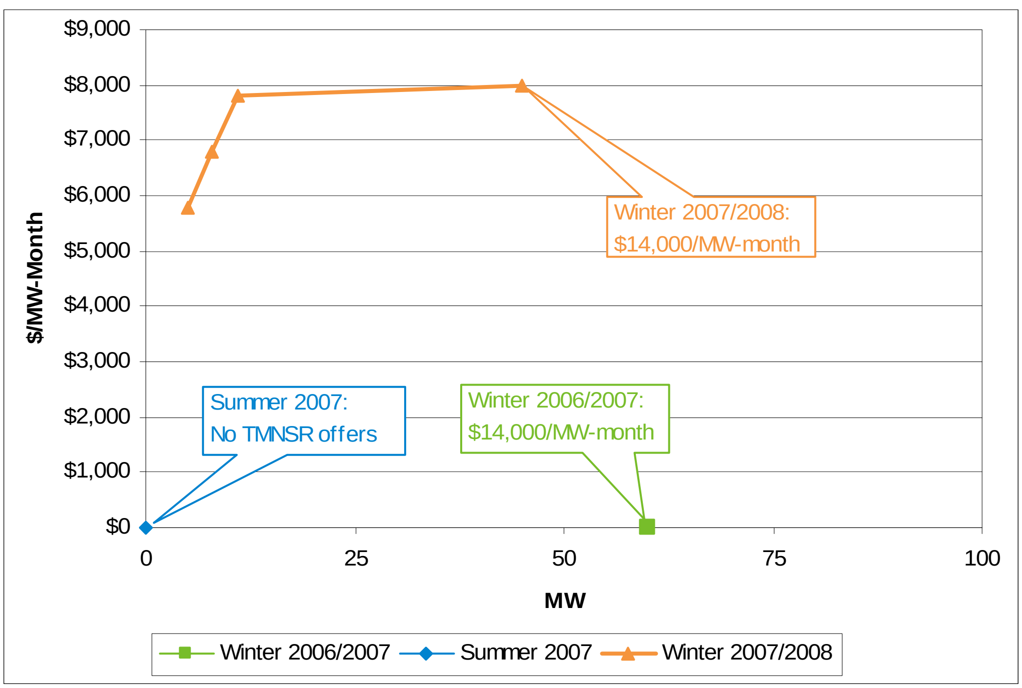

Figure 3-5: NEMA TMNSR Offer Curves, Winter 2006/2007, Summer 2007, and Winter 2007/2008 Forward Reserve Auctions

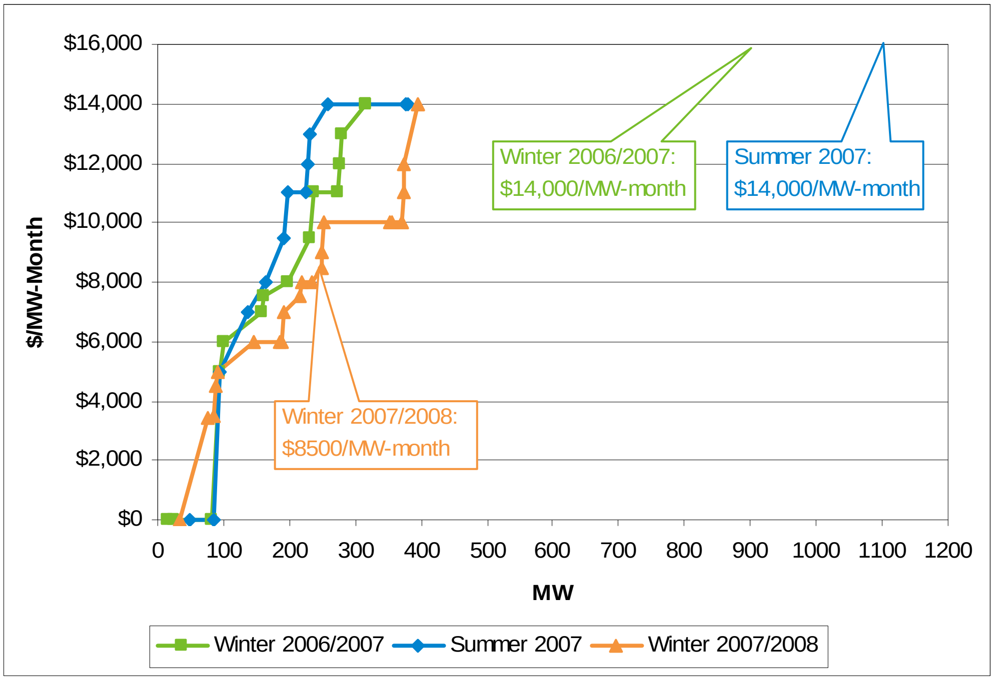

Figure 3-6: NEMA TMOR Offer Curves, Winter 2006/2007, Summer 2007, and Winter 2007/2008 Forward Reserve Auctions

3.2.1.3 Forward Reserve Auction Clearing Prices

The auction clearing results are shown in Table 3 and Table 4. The ICAP Transition Rate in the Forward Capacity Market of $3,050/MW-month is subtracted from forward reserve payments.

- In the first locational forward reserve auction, for the Winter 2006/2007 auction, both TMNSR and TMOR in the Rest-of-System zone cleared at $4,200/MW-month. In the second auction, for Summer 2007, TMNSR increased to $10,800/MW-month, while TMOR decreased to $3,550/MW-month. In the Winter 2007/2008 auction, TMNSR cleared at $9,050/MW-month, while no TMOR cleared.

- Offered quantities were short of requirements in SWCT and CT in all of the auctions. Consequently, the clearing prices in these areas were set to the offer cap of $14,000/MW-month as directed in the Forward Reserve Manual, section 2.6.1.

- Offered quantities were short of requirements in NEMA in the Summer 2007 auction, as was the case in the previous auction, and the clearing price was set to $14,000/MW-month. In the Winter 2007/2008 auction, requirements in NEMA were met. The clearing price for TMOR was $8,500/MW-month, and the clearing price for TMNSR was $14,000/MW-month. TMNSR cleared at $14,000/MW-month in NEMA even though there is no TMNSR requirement in NEMA and both the NEMA TMOR and Rest-of-

System TMNSR prices were under $14,000/MW-month. This occurred because it was the least expensive way to simultaneously meet all of the reserve requirements:

The 45 MW of TMNSR that cleared in NEMA was priced at $8,000/MW-month. Had this 45 MW not cleared, an additional 45 MW of TMOR would have cleared in NEMA at $13,995/MW-month (based on offers submitted) and an additional 45 MW of TMNSR would have cleared at $9,550/MW-month (based on offers submitted) in Rest-of-System (a total of 90 MW). This scenario would have been more expensive than clearing the 45 MW in NEMA and pricing it at $14,000/MW-month. The TMNSR clearing price in NEMA is the sum of the Rest-of-System TMNSR clearing price + shadow price of NEMA interface. The Rest-of-System TMNSR clearing price is $9,050/MW-month; the NEMA shadow price is $8,500/MW-month. The sum is $17,550/MW-month, which was capped to $14,000/MW-month. The TMNSR in NEMA meets two requirements simultaneously (NEMA TMOR and system-wide TMNSR) and, therefore, has a higher price than NEMA TMOR.

Table 3: Supply: Offered and Cleared by Reserve Zone, Summer 2007

Case ID	Location ID	Location Name	Product Type	Offered MWs	Cleared Supply MWs	Clearing Price, $/MW-month
52	7000	ROS	TMNSR	1,001.00	691.20	$10,800.00
52	7000	ROS	TMOR	299.40	106.80	$3,550.00
52	7001	SWCT	TMNSR	0.00	0.00	$14,000.00
52	7001	SWCT	TMOR	515.00	515.00	$14,000.00
52	7002	CT	TMNSR	0.00	0.00	$14,000.00
52	7002	CT	TMOR	210.00	210.00	$14,000.00
52	7003	NEMABSTN	TMNSR	8.80	8.80	$14,000.00
52	7003	NEMABSTN	TMOR	379.00	379.00	$14,000.00

Table 4: Supply: Offered and Cleared by Reserve Zone, Winter 2007/2008

Case ID	Location ID	Location Name	Product Type	Offered MWs	Cleared Supply MWs	Clearing Price, $/MW-month
53	7000	ROS	TMNSR	1,192.32	805.00	$9,050.00
53	7000	ROS	TMOR	448.00	0.00	$0.00
53	7001	SWCT	TMNSR	0.00	0.00	$14,000.00
53	7001	SWCT	TMOR	324.50	324.50	$14,000.00
53	7002	CT	TMNSR	0.00	0.00	$14,000.00
53	7002	CT	TMOR	625.00	625.00	$14,000.00

Case ID	Location ID	Location Name	Product Type	Offered MWs	Cleared Supply MWs	Clearing Price, $/MW-month
53	7003	NEMABSTN	TMNSR	45.00	45.00	$14,000.00
53	7003	NEMABSTN	TMOR	395.50	235.00	$8,500.00

3.2.2 Bilateral Trading

Bilateral trading of forward reserve obligations has been added as an important new feature of the Forward Reserve Market. Bilateral trades as a percentage of total forward reserve MW are shown in Figure 3-7. On average during the Reporting Period, about 28% of total auction obligations were sold through bilateral trading.[3] The increase in bilateral trading from October to November is related to the transfer of ownership/control of assets from one market participant to another, *i.e.*, a participant with a reserve obligation sold generation assets and also traded the reserve obligation. Overall, bilateral trading appears to be used by participants to manage their obligations, rather than as a means to buy and sell for profit.

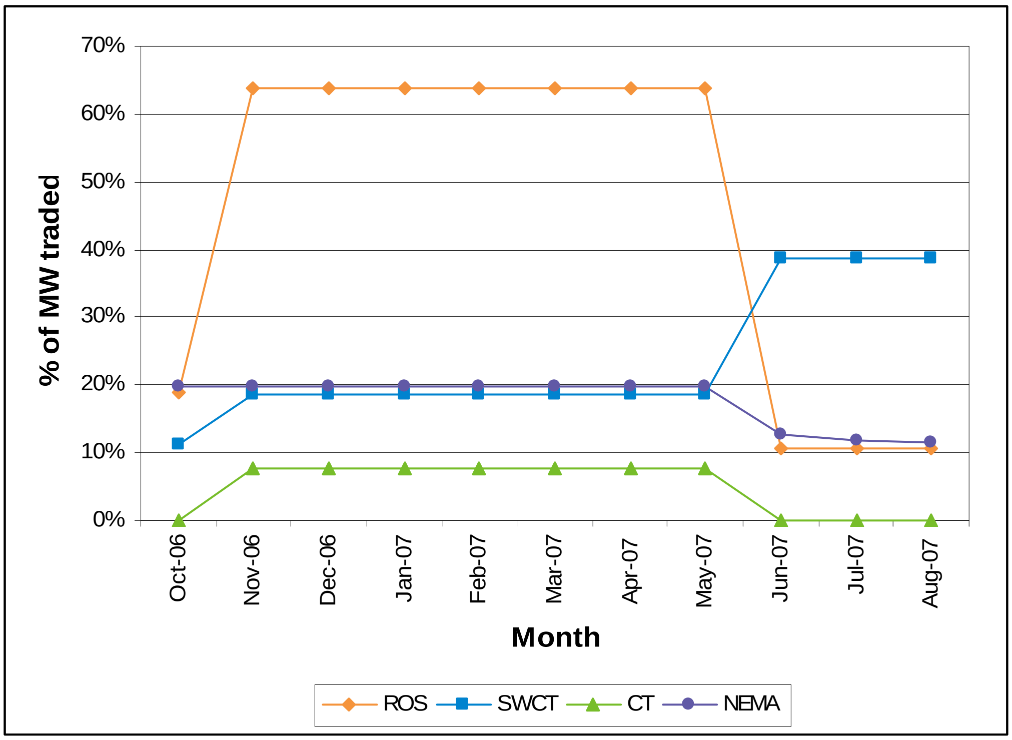

Figure 3-7: Bilateral Trading of Forward Reserve Obligations, Percentage of MW Traded, October 2006 – August 2007

[3] Bilateral trading data presented in the second reserve market compliance report was not weighted by MW. During the October 1, 2006 – January 31, 2007 period covered in the second report, about 32% of auction obligations were traded bilaterally.

3.2.3 Designated Reserve Resources

Figure 3-8 shows the total forward reserve MW assigned in each reserve zone broken out by generator technology. Fast start units include reciprocating engines and combustion turbines. Non-fast start units include fossil-fuel fired steam plants and combined cycle units: these units would typically have to be online in order to provide reserves. Hydro units that were assigned forward reserve obligations were either pumped storage or pondage.

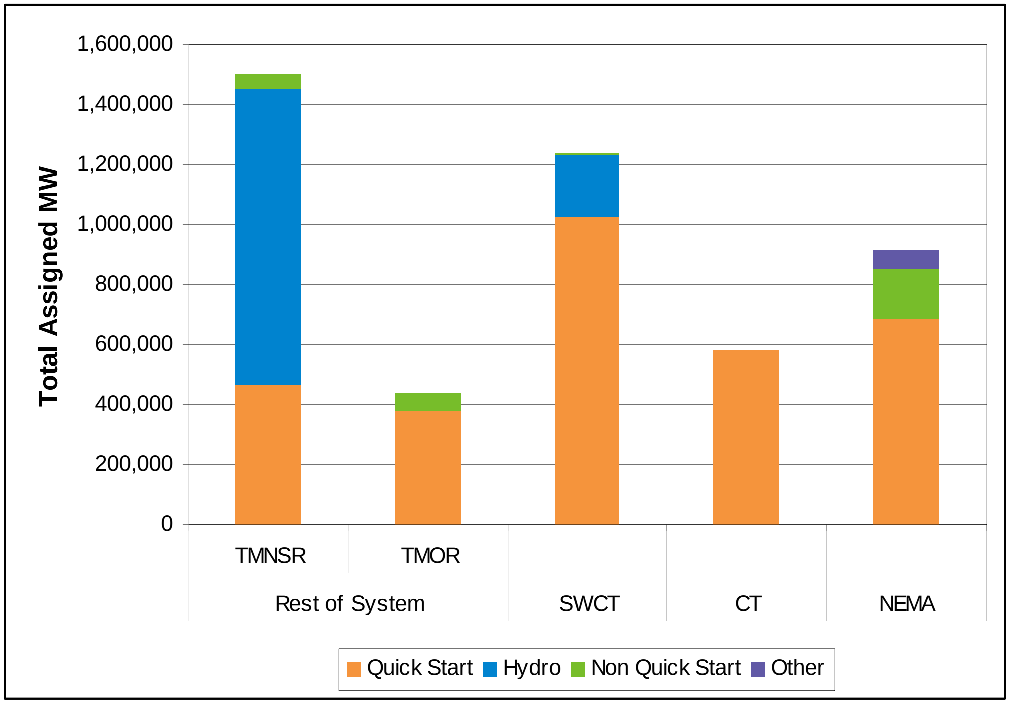

Figure 3-8: Forward Reserve Assigned Resources by Technology, February – August 2007

3.2.4 New Generation Investment

One of the goals of the reserve markets is to attract investment in generation that can respond quickly to a contingency. Analysis of participant offers into the Forward Reserve Market and newly commercial generation indicates that new capacity has been attracted to the market. Specifically, during the Reporting Period, there has been an increase in participant offers of approximately 90 MW in Connecticut.

3.2.5 Forward Reserve Threshold Price

The formula for determining the forward-reserve threshold price is fixed for the duration of the forward-reserve service period. It is set such that a generating resource offering electric energy at this level would be expected to operate at an annual capacity factor of 2% to 3%.[4] The forward-reserve strike price changes monthly with fuel-price indices and is calculated as a heat rate times a fuel index. The forward-reserve heat rate is fixed in the auction notice and does not change during the forward-reserve service period. The threshold price calculation uses the lesser of an index for No. 2 fuel oil and an index for natural gas. Throughout the Reporting Period, the natural gas index was the lower of the two indices.

Participants must meet their cleared portfolio-based obligations by assigning these obligations to eligible generating or Dispatchable Asset Related Demand Resources. They do this by offering or bidding them into the Real-Time Energy Market at a $/MWh rate that is greater than or equal to the forward-reserve threshold price.

Table 5 shows the percentage of hours in each month with on-peak Locational Marginal Prices (LMPs) that equaled or exceeded the threshold price. A threshold price can be lower than the LMP if the fuel index used in the calculation of the threshold price was lower than actual prices or if LMPs were often set by generators that burned a higher-priced fuel than the fuel used in the fuel index. In addition, the threshold price can be lower than the LMP if system conditions caused LMPs to be set by generators with higher heat rates than used in the threshold price. When the LMP exceeds the threshold price, resources that bid at or above the threshold price can be dispatched to provide energy rather than remain unloaded to provide reserves. When the threshold price is too high, participants may have difficulty offering above the threshold price without violating energy offer mitigation screens.

Table 5: Percentage of Hours with Real-Time LMP
Greater than or Equal to Forward Reserve Market Threshold Price
February 1 - August 31, 2007

	Hub	CT	NEMA
FEB2007	0%	0%	0%
MAR2007	3%	13%	3%
APR2007	2%	5%	1%
MAY2007	1%	14%	1%
JUN2007	0%	12%	1%
JUL2007	1%	13%	1%
AUG2007	21%	35%	20%

[4] For each service period, a forward-reserve heat rate is established on the basis of a historical study and announced before the forward-reserve auction. The forward-reserve strike price is calculated using the forward-reserve heat rate defined for the service period and the forward-reserve fuel index, which changes with market conditions. Forward-reserve assumptions are posted on the ISO's web site, at http://www.iso-ne.com/markets/othrmkts_data/res_mkt/cal_assump/2006/index.html.

Figure 3-9 compares the threshold price with a price calculated by multiplying the heat rate and the natural gas price for each day. This figure shows that in August 2007, when the LMP exceeded the Forward Reserve Market threshold price in 21% of hours at the hub, the price based on the daily natural gas prices was higher than the threshold price on many days.

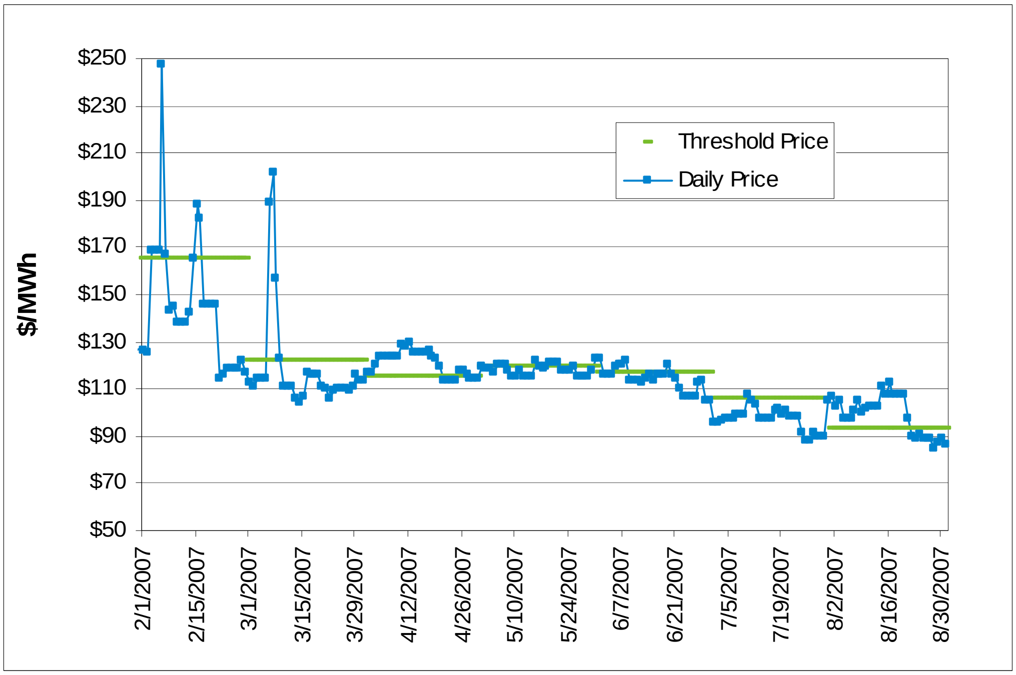

Figure 3-9: Forward Reserve Threshold Price vs. Daily Gas Price * Heat Rate, February 1 - August 31, 2007

4 Real-Time Reserve Pricing

4.1 Design Objectives and Main Features

Real-time reserve pricing is intended to send price signals reflecting the value of reserves and to encourage generators to provide reserves during periods of relative scarcity. Real-time reserve prices are designed to price the variable opportunity cost of providing reserves. Under the design, prices for reserves and energy should reflect actual system operating conditions.

In real time, resources are dispatched in the least cost way to simultaneously meet energy and reserve requirements of the system, while respecting transmission security constraints. The real-time reserve requirements include a system TMSR requirement, a system TMNSR requirement, a system TMOR requirement, and zonal TMOR requirements for each reserve zone. Zonal reserve requirements may be met by resources within the reserve zone, and by resources outside of the reserve zone through the unused import capability of the reserve zone transmission interface.

Real-time reserve requirements are developed to ensure recovery from the loss of the largest resources on the system, and recovery of required reserves to ensure recovery from a second contingency to meet NPCC and ISO New England reserve requirements. In accordance with operating practices, the system TMSR requirement and the system TMNSR requirement are based on the system's largest contingency, and the system TMOR requirement is based on the system's second largest contingency. Zonal TMOR requirements are based on losing a line or generator in the local area and recovering from that loss to ensure next contingency coverage within 30 minutes of the initial event within a local reserve zone.

Corresponding to each reserve requirement constraint, there is a Reserve Constraint Penalty Factor (RCPF). An RCPF is a penalty price that is used when the reserve requirement can not be met. The current RCPF values are listed in Table 6.

Table 6: RCPF Values

Reserve Requirement	RCPF ($/MWh)
System TMSR	$50
System TMNSR	$850
System TMOR	$100
Zonal TMOR	$50

Real-time reserve prices are calculated every five minutes, together with LMPs for energy. Real-time reserve prices are expected to be zero most of the time since there are usually sufficient reserves available based on the normal economic dispatch and there are no additional costs to provide reserves. Non-zero reserve prices occur when resources are redispatched to meet reserve requirements. During these periods, market participants may incur opportunity costs when units are redispatched away from their normal energy-only optimal output to provide reserves. In such case, the marginal opportunity costs determine the reserve clearing prices. The cost of redispatch is also reflected in energy prices.

Redispatch of resources ends when opportunity costs reach the RCPF values and reserves then become deficient. Therefore, RCPF values set the real-time reserve prices when there are insufficient reserve resources to meet the reserve requirements, or the opportunity costs incurred by redispatching the system for reserves would be higher than the RCPF values. The corresponding events are referred to here as reserve shortage events. Importantly, RCPF values cascade up from inferior to superior products. For example, if the system, even after economic co-optimized redispatch, were to become deficient in both TMSR and TMNSR, the real-time clearing price of TMNSR would be set to $850/MW-month, and the price of TMSR would be $900/MW-month. No such deficiencies have occurred.

4.2 Results

4.2.1 Real-time Reserve Requirements

The average level of each reserve requirement during the Reporting Period is shown in Table 7, and the monthly average reserve requirements are shown in Figure 4-1. The values shown are cumulative. The system TMNSR requirement includes both system TMSR and TMNSR, and is equal to the system largest contingency. System TMOR includes the ten-minute requirement as well as TMOR and equals the largest contingency on the system plus 50% of the second largest contingency. On average, the system TMSR requirement was about 39.2% of the total system ten minute requirement. In general, the average requirements were consistent over the Reporting Period, as shown in Figure 4-1.

Table 7: Real-time Reserve Requirements

Reserve Requirement	Average (MW)
SYSTEM TMSR	526.32
SYSTEM TMNSR (TMSR + 10-min non-spin)	1333.80
SYSTEM TMOR (TMNSR + 30-min OR)	1930.29
NEMA/Boston TMOR	1432.14
CT TMOR	1057.46
SWCT TMOR	631.26

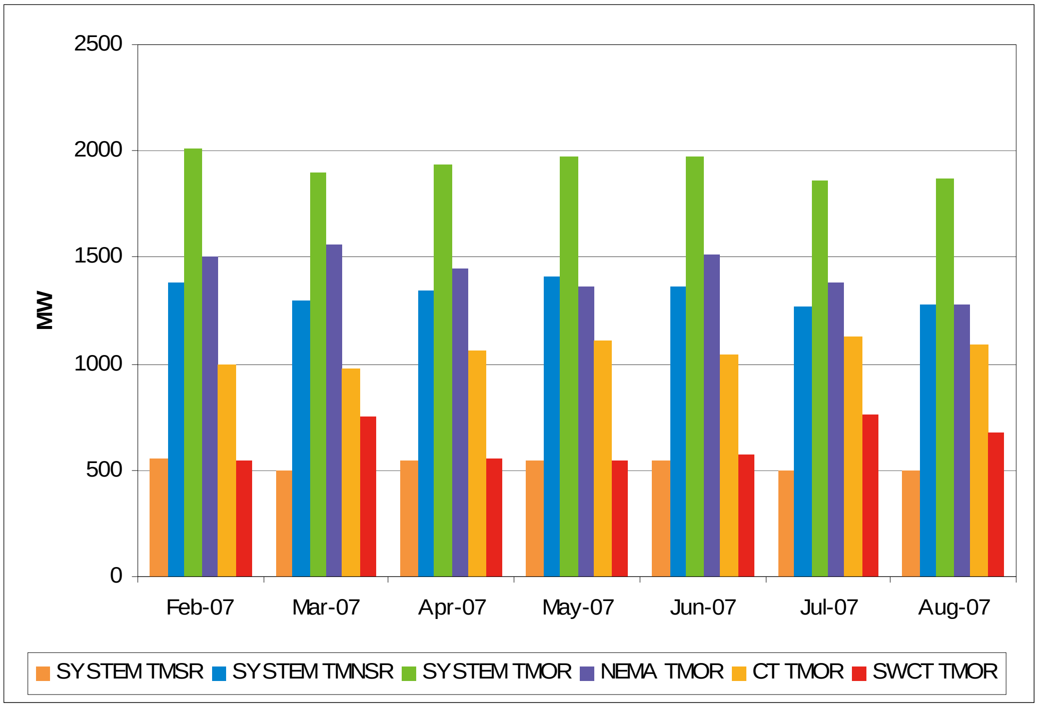

Figure 4-1 Monthly Average Reserve Requirements

4.2.2 Reserve Pricing Events

When energy and reserve requirements cannot be met through normal economic dispatch, reserve constraints become binding, leading to redispatch of the system.[5] Binding reserve constraints lead to non-zero reserve prices in real time. For purposes of this report, a reserve event occurs when a reserve constraint binds in one or more consecutive five-minute intervals.

[5] A constraint is considered to be binding if changing the constraint also changes the optimal solution.

For example, if a constraint binds for three intervals (15 minutes), this counts as a single reserve event.

Information about reserve events during the Reporting Period is summarized in Table 8. The statistics in the table are based on five-minute interval data, for each type of reserve requirement. Reserve events are grouped into two categories: short duration events which last less than 30 minutes, and long duration events which last more than 30 minutes. Short duration events usually resulted from transient system conditions. The total minutes of each type of reserve event, the percentage of total time during which there were reserve events, the total number of reserve events, the total number of long duration events, the total minutes of the long duration events, and the percentage of the long duration events are shown in this table. The monthly total minutes of reserve events over the Reporting Period are shown in Figure 4-2.

Table 8: Summary of Reserve Pricing Events

Reserve Requirement	Total Event Minutes [A]	Percentage [A]/Total Period Minutes	Total Reserve Events	Long Duration Events	Total Minutes of Long Duration Events [B]	Percentage of Long Duration Events [B]/[A]
SYSTEM TMSR	1820	0.60%	102	10	570	31.32%
SYSTEM TMNSR	705	0.23%	29	7	355	50.35%
SYSTEM TMOR	275	0.09%	5	3	245	89.09%
NEMA/Boston TMOR	190	0.06%	2	1	180	94.74%
CT TMOR	2955	0.97%	81	32	2360	79.86%
SWCT TMOR	475	0.16%	14	9	400	84.21%

The statistics yield the following observations. Over the entire Reporting Period, reserve events occurred less than 1% of the time. System TMSR events occurred more often than system TMNSR and system TMOR events. Most of the reserve events were of short duration. However, the majority of the total time during which there were reserve events was related to long duration events that lasted more than 30 minutes. For system TMSR requirement, the total minutes of reserve events were mainly due to short duration events.

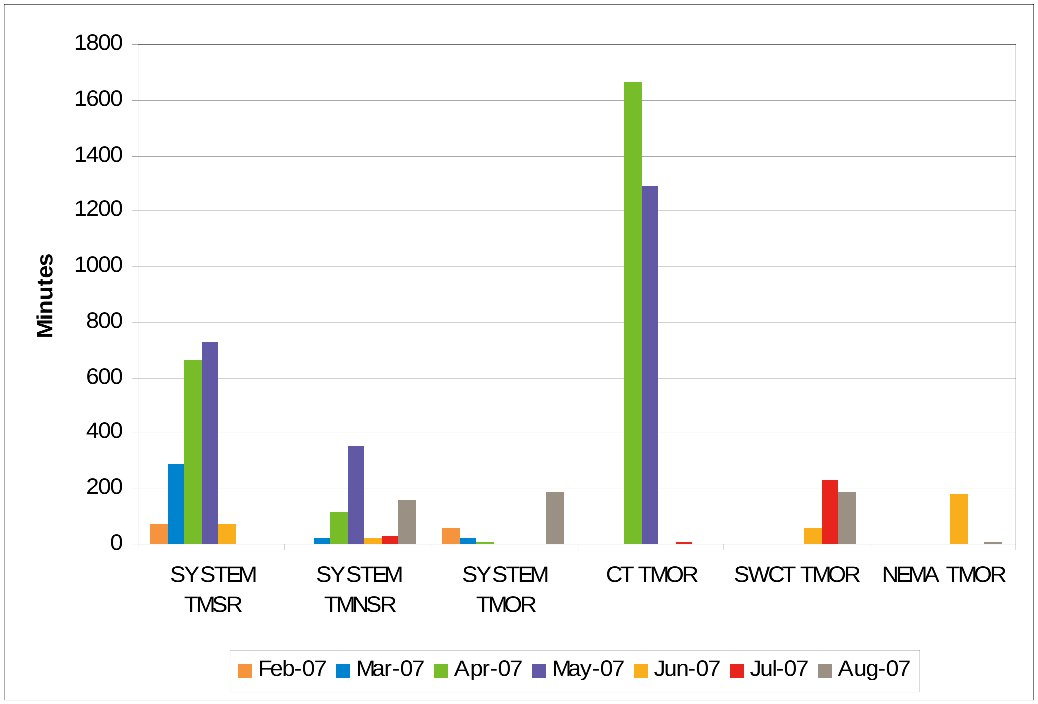

Figure 4-2: Monthly Total Minutes of Pricing Reserve Events

Figure 4-2 shows that Connecticut TMOR pricing events occurred more often in April and May. These events were due primarily to generator outages, which reduced available capacity within Connecticut, and to combinations of generator outages and high exports to New York.

4.2.3 Reserve Shortage Events

A reserve shortage event occurs when the real-time clearing price is equal to the RCPF value or, equivalently, the system or reserve zone is deficient for that reserve product. The reserve shortage events during the Reporting Period are summarized in Table 9, and the trends over the Reporting Period are shown in Figure 4-3. The Connecticut TMOR requirement was short 0.33% of the time, and a shortage of all other reserve requirements occurred less than 0.1% of the time. System TMOR shortage events occurred more often than shortage events for other system reserve requirements. The system TMNSR requirement was never short during the Reporting Period.

Table 9: Summary of Reserve Shortage Events

Reserve Requirement	Total Shortage Event Minutes	Percentage of all hours in Reporting Period
SYSTEM TMSR	25	0.01%
SYSTEM TMNSR	0	0.00%
SYSTEM TMOR	90	0.03%
NEMA/Boston TMOR	190	0.06%
CT TMOR	1020	0.33%
SWCT TMOR	145	0.05%

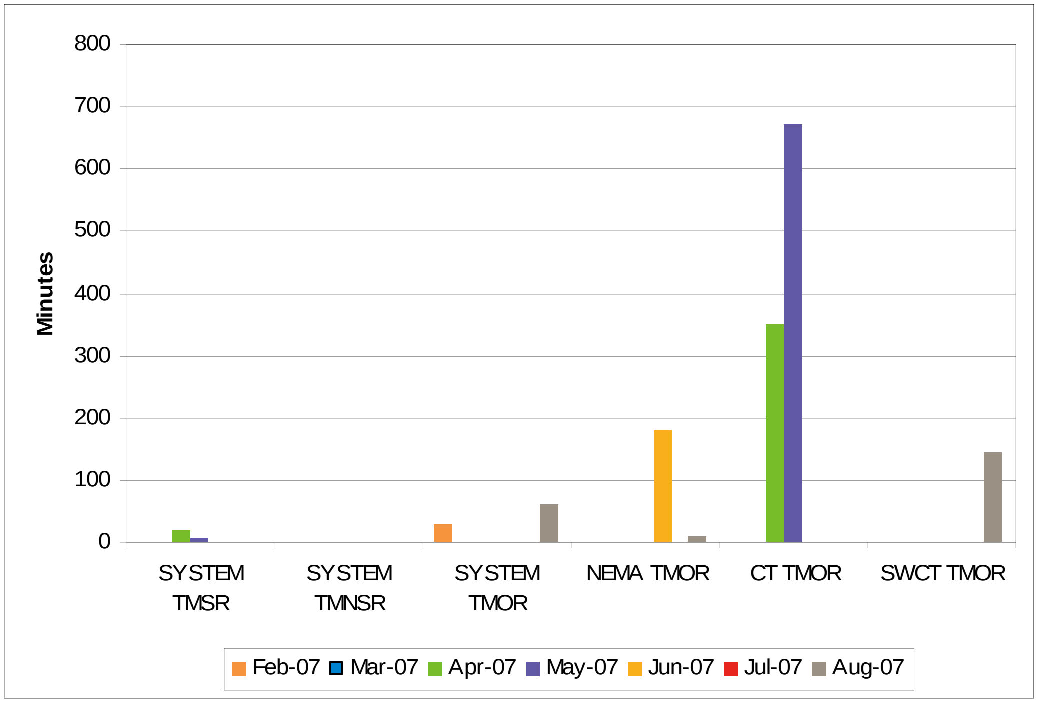

Figure 4-3: Monthly Total Reserve Shortage Minutes

Connecticut zonal reserve shortage events occurred in April and May. These events were due to transmission line limit reductions, which limited import capacity into Connecticut, generator outages and load conditions. On May 9, in particular, reduced line limits caused by a tripped unit resulted in reserve constraint violations for much of the afternoon.

The NEMA/Boston reserve shortage events that occurred in June were related to a combination of system conditions, including high demand and the outage or reduced capability of two generating units within the local reserve zone.

The shortage events in SWCT that occurred during the afternoon of August 2 were due to load patterns and increased energy imports that limited the unloaded interface capability. Demand for electricity was 26,143 MW on August 2, the highest recorded demand for the summer 2007 season.

4.2.4 External Reserves Support

Zonal reserve requirements can be met by internal resources and imported reserves, called "external reserve support" (ERS), which is unused import capability of the associated reserve zone interface. In New England's real-time co-optimized energy and reserve market, the amount of internal resources providing reserve and the amount of imported reserve are optimally determined so that the energy and reserve requirements of the system are met at least cost. The ratio of imported reserves to the zonal reserve requirement was calculated for each reserve zone for the Reporting Period. Table 10 shows the average ratio over all intervals and the average ratio over the binding intervals (intervals during which the available local TMOR plus the ERS is less than or equal to the real-time reserve requirement). The average ratios over binding intervals are significantly lower than the corresponding average ratios over all intervals. This is to be expected; a ratio greater than 100% indicates that unloaded interface capability is greater than the entire local requirement. The Connecticut reserve zone had the lowest average ratios, especially for the value over binding intervals.

Table 10: Ratio of Imported Reserve to the Zonal Reserve Requirement

Reserve Zone	Average Ratio over all Intervals	Average Ratio over binding intervals
NEMA/Boston	183.70%	61.50%
CT	166.79%	25.86%
SWCT	173.25%	39.02%

4.2.5 Reserve Zone Interface Proxy Limit Activation

The $50/MWh RCPF value for the local TMOR requirement was derived to reflect redispatch costs as well as market power concerns. In real time, redispatch ends when the marginal opportunity cost of providing reserves reaches the RCPF value. Therefore, for zonal reserve, redispatch ends when the marginal opportunity cost reaches $50/MWh, and the actual amount of reserves designated cannot meet the requirement. Under this situation, system operators usually bind the corresponding proxy transmission interface limit in order to provide local second contingency protection.[6] The second contingency proxy limit is less than or equal to the first

[6] The ISO system operating procedure *Monitor System Security*, available at http://www.iso-ne.com/rules_proceds/operating/sysop/rt_mkts/sop_rtmkts_0060_0020.pdf explains the calculation of proxy interface limits.

contingency interface limit to which the system is operated pre-contingency. Manually binding the second contingency proxy limit reduces the loading of the interface and forces the redispatch of resources within the import constrained zone. During the Reporting Period, the Connecticut proxy limit was manually bound after RCPFs set the zonal reserve prices on eleven days in April and May. There were only 23 days with positive reserve prices in Connecticut that did not result from price cascading from the system: the proxy limit was manually bound in almost half of these days.

4.2.6 Real-Time Reserve Clearing Prices

Average real-time reserve prices for each type of reserve at each location are shown in Table 11. Note that clearing prices cascade up from inferior to superior products. For example, the average system TMSR price of $0.20/MWh is based on the average cost of $0.09/MWh to meet the system TMSR requirement, the average cost of $0.07/MWh to meet the system TMNSR requirement, and the average cost of $0.04/MWh to meet the TMOR requirement. In addition, system prices cascade to reserve zone prices for the same products. Figure 4-4 shows the percent of hours with non-zero reserve prices.

Table 11: Average Real-Time Reserve Clearing Prices ($/MWh)

Location	TMSR	TMNSR	TMOR
Rest-of-System	$0.20	$0.11	$0.04
NEMA	$0.23	$0.14	$0.07
CT	$0.46	$0.37	$0.30
SWCT	$0.49	$0.41	$0.34

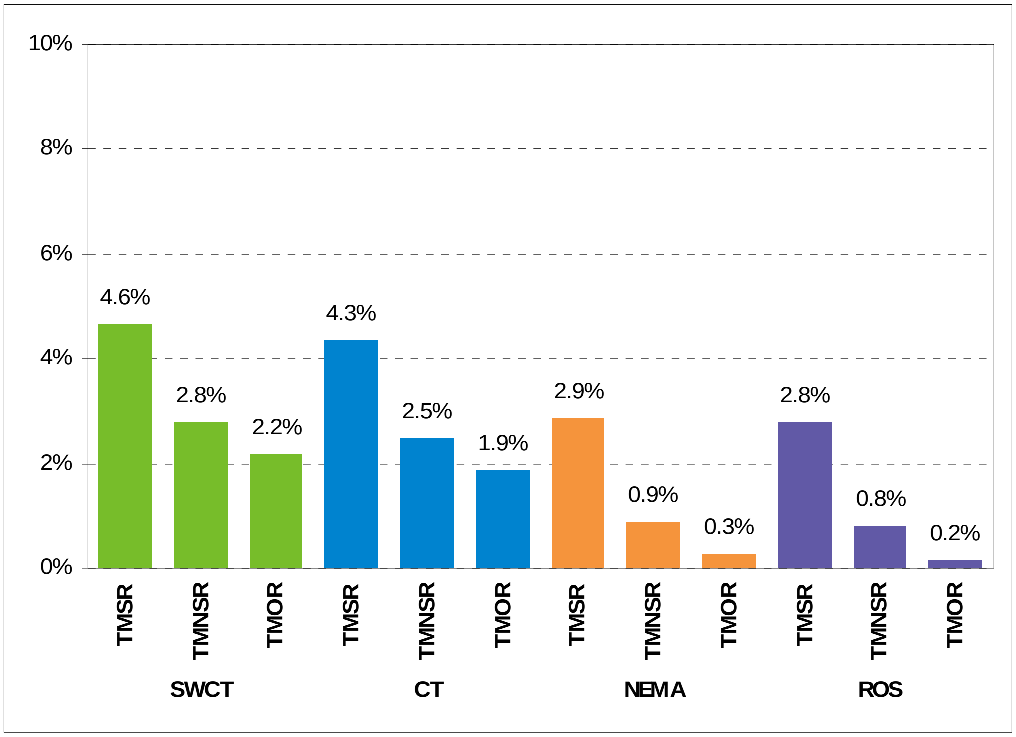

Figure 4-4: Real-Time Non-Zero Hourly Reserve Price Frequency, February – August 2007

Figure 4-5 through Figure 4-8 show the distribution of prices in all hours of the Reporting Period for all areas. Even though non-zero prices occurred for only a small number of periods, the figures show that even within non-zero priced periods, very high prices (above $50/MWh) occurred infrequently.

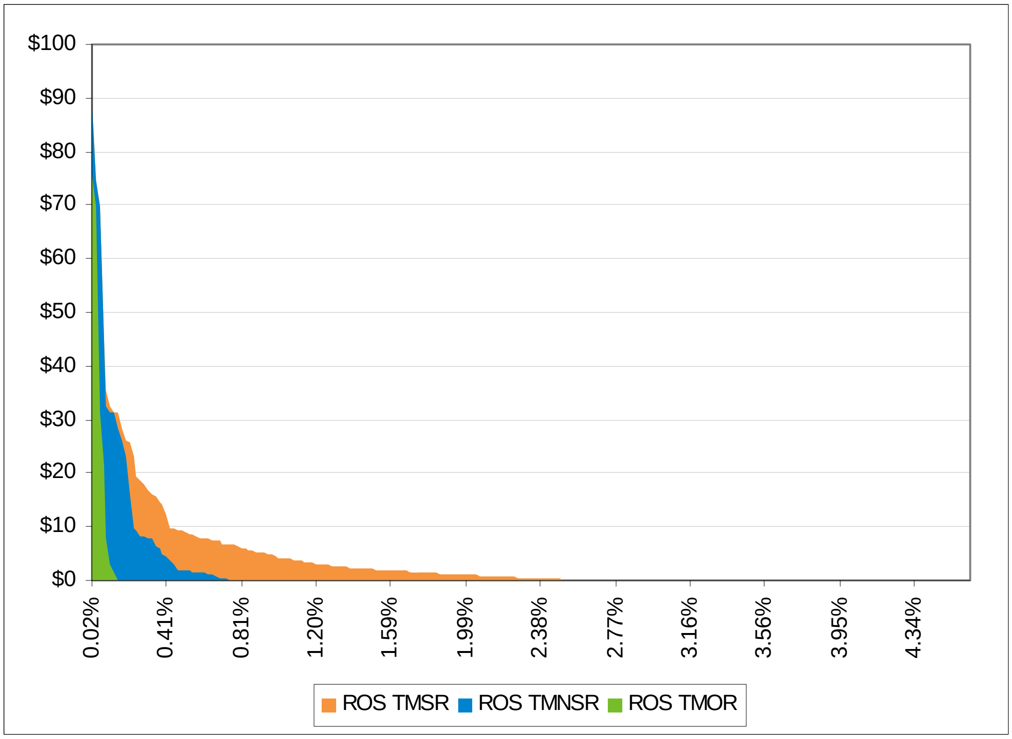

Figure 4-5: Real-Time Price Duration Curve, System-Wide

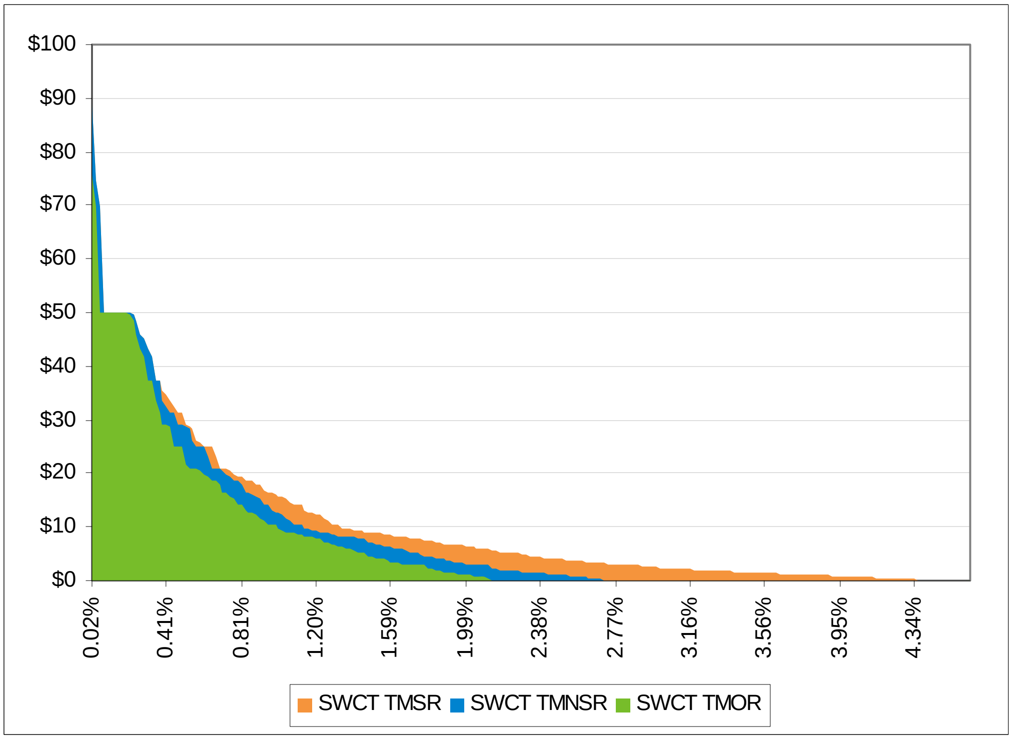

Figure 4-6: Real-Time Price Duration Curve, Southwest Connecticut

Figure 4-6 shows prices in SWCT. Positive reserve prices were mostly due to the occurrence of redispatch or deficiency for CT TMOR, with the remainder of the contribution to TMSR prices caused by occasional redispatch of units for system-wide TMSR. CT TMOR prices exceeded $50/MWh at times due to the system TMOR price cascading to the CT TMOR price. As Table 9 above confirms, only a small fraction of local SWCT positive reserve prices was due to local shortages, with the remainder caused primarily by redispatch for and deficiency of CT TMOR.

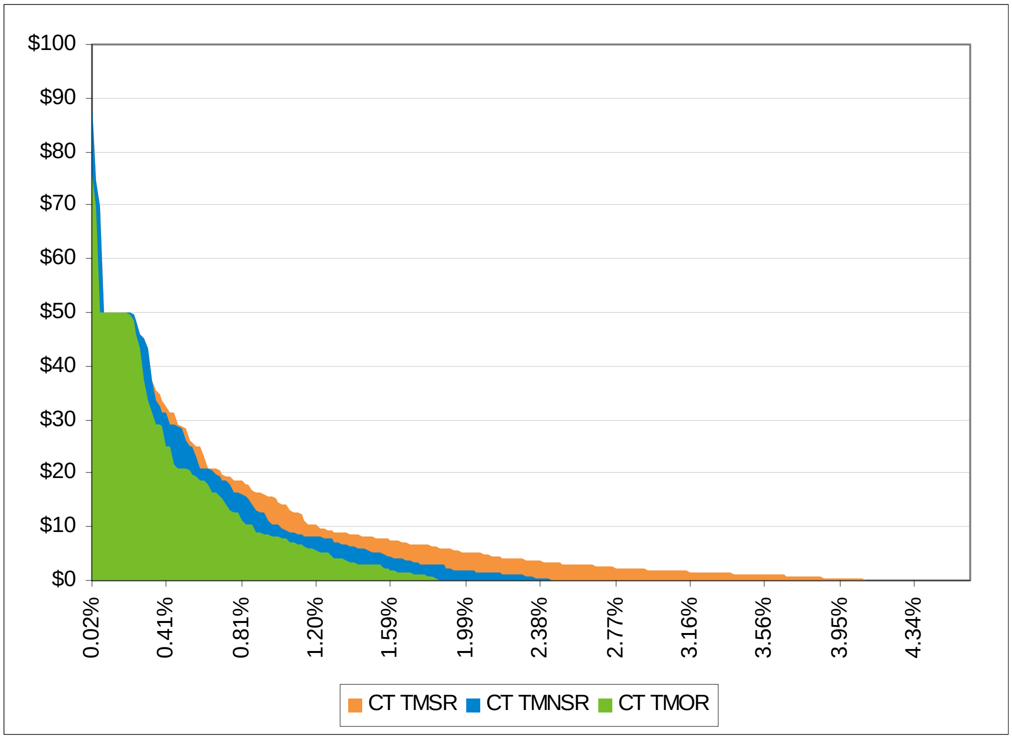

Figure 4-7: Real-Time Price Duration Curve, Connecticut

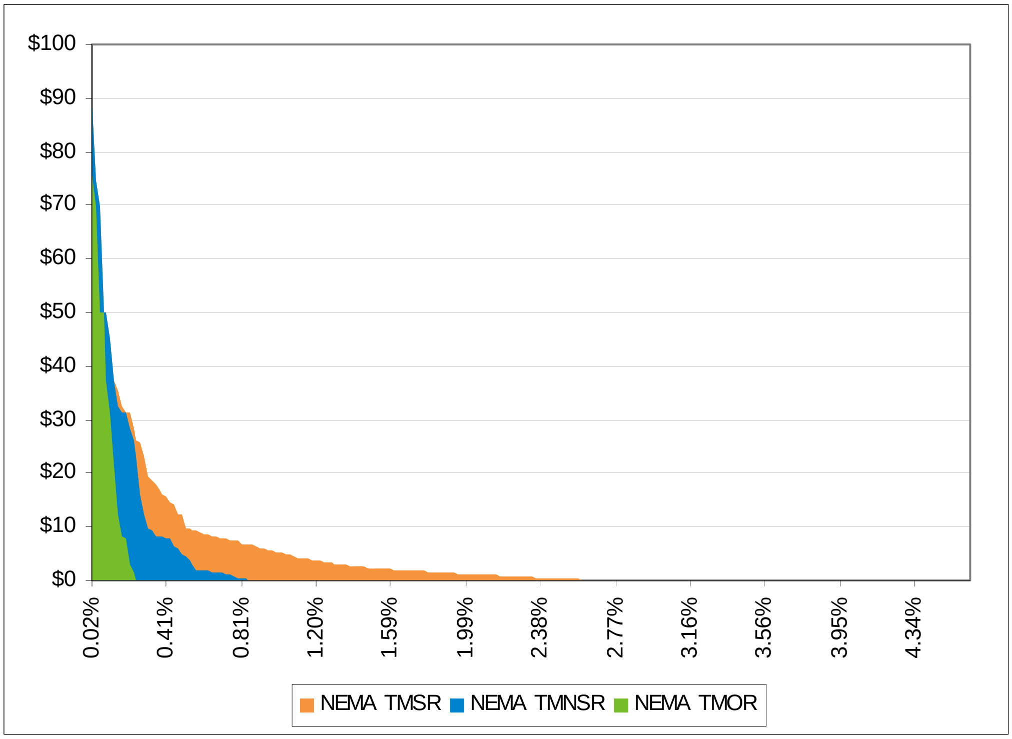

Figure 4-8: Real-Time Price Duration Curve, NEMA/Boston

4.2.7 An OP4 Event Related Analysis

There were two system wide OP4 events during the Reporting Period. The OP4 event that occurred on February 10, 2007 was covered in the April 2, 2007 Reserve Report. A second OP4 event occurred on August 2, 2007.

System demand peaked between 4:00 PM and 5:00 PM at 25,978 MW on August 2, within 10 MW of placing it on the Top 10 List of highest demand days for New England. High demand, coupled with generator outages and reductions, resulted in capacity deficiencies and implementation of Master/Local Control Center Procedure No. 2 (M/LCC 2) from 2:30 p.m. to 8:30 p.m. and OP4 Actions 1 and 6 from 3:30 p.m. to 6:00 p.m.

Figure 4-11 shows the real-time hub LMP over the day with reserve prices, while Figure 4-9 and Figure 4-10 show the actual quantity of TMOR and TMNSR and the reserve requirements. Although TMNSR was never short (TOTAL30MW was always at least TOTAL30REQ), as Figure 4-10 shows, between approximately 2:00 p.m. and 4:00 p.m. the constraint was binding, resulting in co-optimized redispatch of the system and consequent positive reserve prices. During hour ending 4:00 p.m., system TMOR went short, coinciding with the declaration of OP4 at 3:30 p.m. LMPs during this period reflected the effect of the reserve shortages.

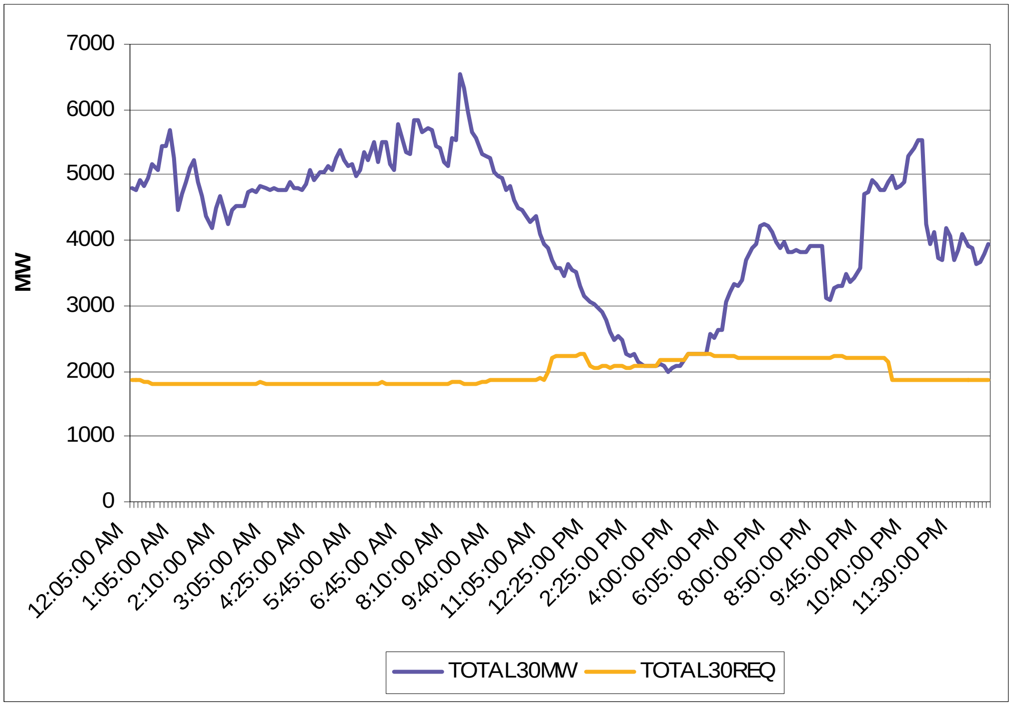

Figure 4-9: August 2, 2007, Total 30 Minute Reserve Requirements vs. Actual

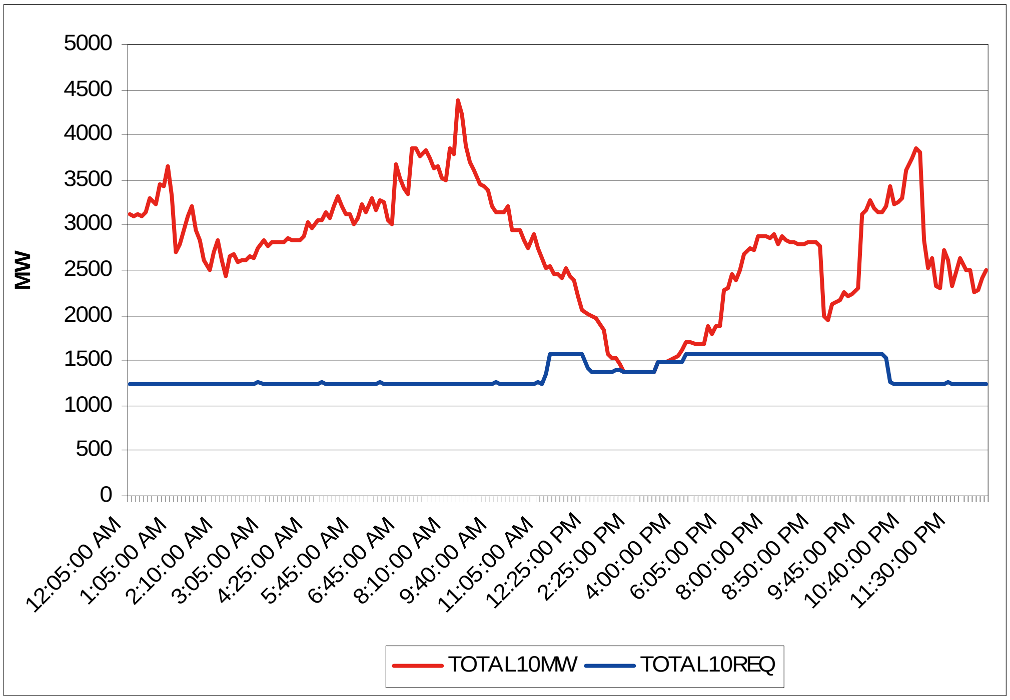

Figure 4-10: August 2, 2007, Total 10 Minute Reserve Requirements vs. Actual

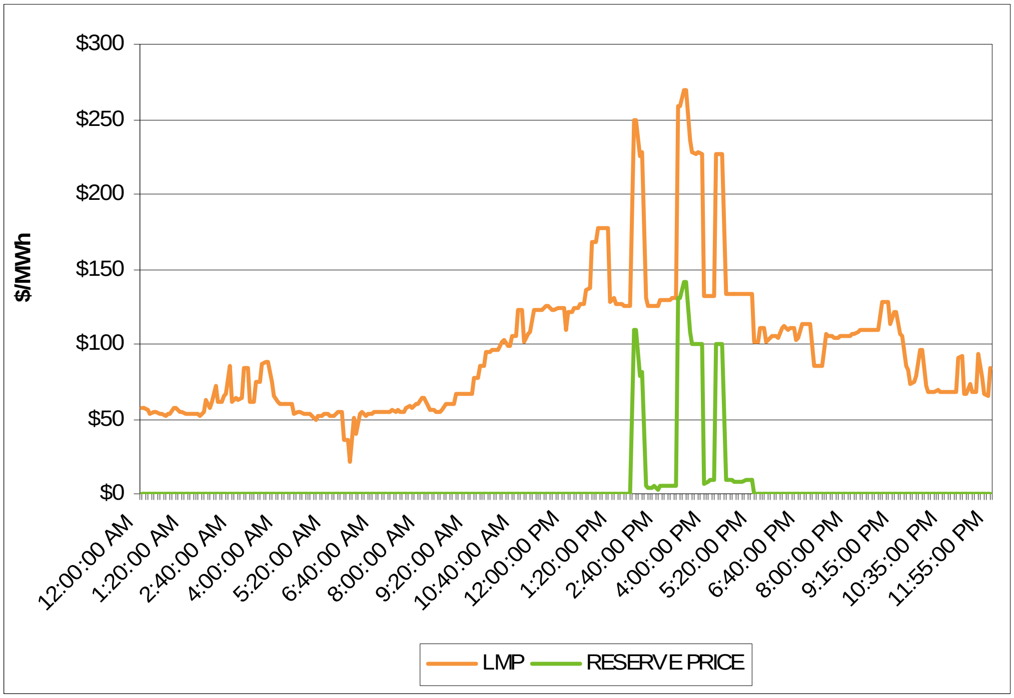

Figure 4-11 August 2, 2007, 5-minute Hub LMP and System TMSR Price

Table 12: Hourly Reserve Clearing Prices, August 2, 2007

Hour Ending	TMSR Clearing Price ($/MWh)	TMNSR Clearing Price ($/MWh)	TMOR Clearing Price ($/MWh)
14	$9.16	$9.16	$0.00
15	$26.03	$26.03	$0.00
16	$89.24	$89.24	$75.61
17	$31.43	$31.43	$31.43
18	$3.03	$3.03	$3.03

5 Net Commitment Period Compensation and Reserve Market Interactions

5.1 Overview

To meet requirements for ensuring the reliability of New England's bulk power system, the ISO may commit resources in addition to those cleared in the Day-Ahead Energy Market. Resources that the ISO requires to operate but that do not recoup their offers through energy market revenues are paid first-contingency and second-contingency NCPC, voltage reliability cost (VAR) payments, and distribution reliability cost payments.[7] NCPC payments to reliability resources vary from month-to-month for a variety of reasons, including load levels and system conditions, self-scheduling of resources that provide reliability support, and the variable operating costs of resources committed for reliability.

Most reliability commitments are made through the Reserve Adequacy Analysis (RAA) process. The RAA process is designed to maximize the opportunity for the market to respond and minimize the ISO's supplemental commitments to meet reliability criteria. The RAA begins after the reoffer period closes at 6:00 p.m. and is updated periodically throughout the Operating Day. The ISO's RAA process commits resources for voltage control and support before committing for second contingency support. Because it is possible for one resource to solve both VAR and second contingency requirements, commitments for VAR reduce the need for commitments for second contingency.

The Forward Reserve Market TMOR obligations can be met by online generators. Some generators that in the past have been committed by the ISO for reliability in the NEMA and Connecticut load zones are capable of providing TMOR. The ISO analyzed reliability commitments and forward reserve designations to determine whether the revised reserve markets had reduced the need for these commitments.

5.2 NEMA Results

Figure 5-1 shows second contingency and VAR NCPC payments for the NEMA load zone. Second contingency NCPC payments declined after the implementation of revised reserve markets, but VAR NCPC payments increased.

[7] It should be noted that there is not necessarily a relationship between clearing the local Forward Reserve Market requirement and reducing VAR commitments, *i.e.*, the local requirements purchased by the Forward Reserve Market are to meet local second contingency requirements, not VAR.

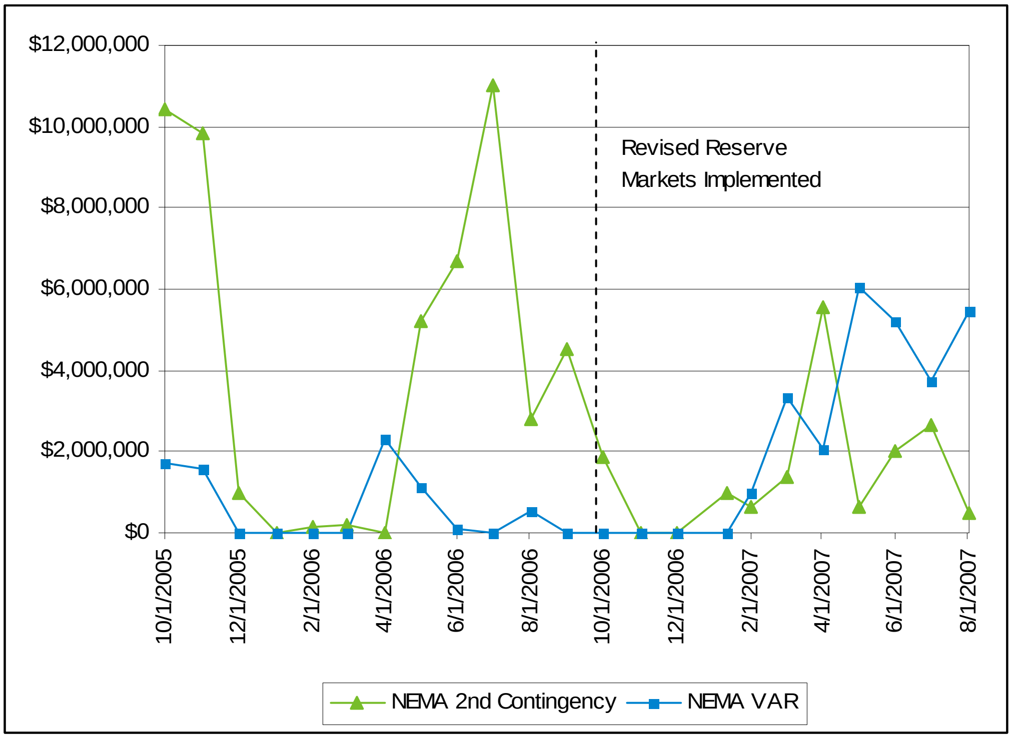

Figure 5-1: NEMA Second Contingency and VAR NCPC Payments, October 2005 – August 2007

Several generators that were committed for reliability and received second contingency NCPC payments during October 2005 to September 2006 were designated as forward reserve resources after October 2006, and thus no longer had to be committed by the ISO. Most of these resources were generators that had been committed infrequently for reliability. Other forward reserve resources that had not previously received NCPC displaced generators that had been committed by the ISO for second contingency support in the past.

However, the ISO still had to make significant supplemental commitments for reliability in NEMA after the implementation of the new Forward Reserve Market. The commitment situation was complicated by the timing of the RAA commitment process, which begins at 6:00 p.m., and the midnight deadline for designating forward reserve resources. Because it is not known which specific units will be designated for forward reserve until after the RAA process, this information cannot be included in the reliability assessment and commitment decisions. This created a situation in which a resource might be committed for reliability only to have a participant self-schedule a similar unit to provide reserves. This situation should occur less frequently during the Winter 2007/2008 reserve period due to the decrease in the NEMA forward reserve requirement.

5.3 Connecticut Results

Figure 5-2 shows second contingency and VAR NCPC payments for the Connecticut load zone.[8] Second contingency NCPC payments declined slightly in Connecticut after the implementation of the new Forward Reserve Market. VAR payments were negligible both before and after implementation.

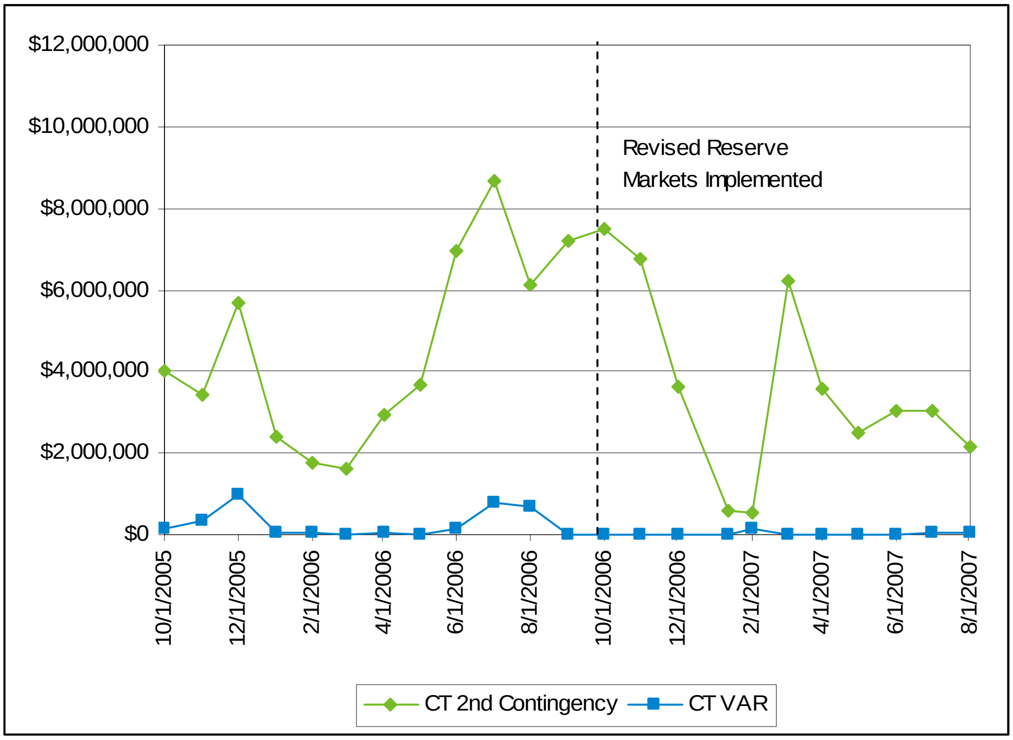

Figure 5-2: Connecticut Second Contingency and VAR NCPC Payments, October 2005 – August 2007

In Connecticut, as in NEMA, some resources that had been committed for reliability prior to the implementation of the new Forward Reserve Market were designated as forward reserve resources after October 1, 2006. Most of these were units that had been committed infrequently for reliability and received small amounts of NCPC payments.

[8] There is no separate SWCT load zone.

6 Performance of Reserve Resources

In conjunction with the revised reserve markets, additional performance monitoring and auditing for resources with claimed reserve capability was implemented. Beginning in January 2007, failure to perform either during normal operations or during audits results in a cap being placed on the megawatt value of reserve credit allowed to the failing resource. The ISO conducts audits on every start of a fast start generator that claims to have 10- or 30-minute off-line reserve capability, and generators' claimed 10-minute and claimed 30-minute reserve values are capped at the megawatt value produced.

Table 13 shows the impact of performance capping on total system claimed 10-minute and claimed 30-minute reserve capability. Claimed 10-minute reserve has been reduced by 1,601 MW, and claimed 30-minute reserve has been reduced by 1,080 MW over the course of the year. Many of the generators that were eliminated from the pool of fast start generators are run-of-river hydropower facilities.

Table 13: Impact of Performance Capping on Claimed Reserve Capability

	Available MW Oct 1, 2006	Available MW Jun 1, 2006	Available MW Sep 24, 2007	Net Difference, Oct 2006 to Sep 2007
Claimed 10-minute	3,715	2,642	2,114	(1,601)
Claimed 30-minute	4,973	3,843	3,894	(1,080)

The performance auditing and capping program has pushed non-performing generators out of the fast start category. The result is that the generators that retained their fast start designations, *i.e.*, those with verified claimed 10-minute and claimed 30-minute reserve capability, start up and perform reliably. This ensures that only resources truly capable of providing reserves from an offline state can participate in the reserve markets.

7 Reserve Payment Settlement Results

The clearing price from the forward-reserve auction is converted into an hourly payment rate based on on-peak hours.[9] Generators assigned daily forward-reserve obligations are paid this hourly price. Payments are reduced by any failure-to-reserve or failure-to-activate penalties. Penalties are assessed if a participant does not offer an available, forward-reserve-capable resource into the energy market at or above the threshold price, or if an assigned resource is not able to provide energy within 10 or 30 minutes if called on during real-time operations.[10]

Payments for forward reserves were approximately $96 million during the Reporting Period. Failure-to-reserve penalties for the Reporting Period totaled $3.5 million. A failure-to-activate penalty of $3,537 was paid in August 2007. All costs relating to compensating generating resources in the Forward Reserve Market are allocated based on real-time load obligations. Figure 7-1 shows Forward Reserve Market payments and penalties for the Reporting Period.

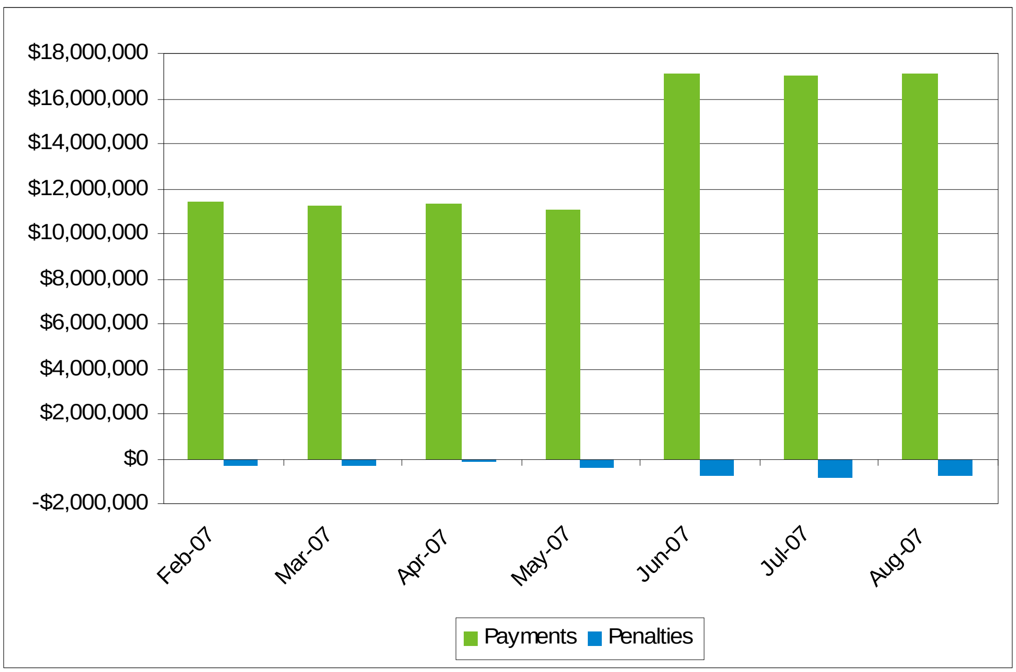

Figure 7-1: Forward Reserve Market Payments and Penalties, February – August 2007

[9] The auction clearing price is adjusted to reflect payments made in the Forward Capacity Market before being converted to an hourly rate.

[10] Participants receive exceptions to the failure-to-reserve penalty for periods when the unavailability is due to scheduled annual maintenance. Failure-to-activate penalties are applied only when control room operators have approved a contingency unit-dispatch software case.

FERC directed the ISO to report on whether increased Forward Reserve Market penalties have created an incentive for sellers to include commitment costs in their forward reserve offers. Forward Reserve Market penalties are intended to provide incentives for participants to make resources available for reserve. The penalties were not designed to encourage particular offer strategies.

Forward reserve offers are portfolio based, and participants can and do use a variety of on and off-line generators to meet their forward reserve obligations. Commitment costs, on the other hand, are generator specific. Commitment costs are per start, while forward reserve offers and the resulting auction clearing price are denominated in $/MW-month. Participants that plan to meet a forward reserve obligation with an on-line unit that is not committed by the ISO must self-schedule the asset, foregoing NCPC payments for commitment costs that are not covered by energy market revenues. Participants that meet a forward reserve obligation with an off-line generator may have difficulty calculating commitment costs since they do not know prior to the auction how often an off-line generator will be started for reserves. A comparison of startup costs of generators that were designated for forward reserves and the forward reserve offer prices of the lead participants of these units does not show a consistent relationship between startup costs and forward reserve offers. Some participants that meet forward reserve obligations with on-line resources do appear to include commitment costs in their offers. However, many offers do not appear sufficiently high to include all commitment costs, while others appear to exceed commitment costs.

Payments to resources that provided real-time reserves totaled $2.17 million during the Reporting Period. Resources assigned to meet forward reserve obligations are often designated as reserve resources in real time.[11] When real-time reserve payments are positive and a resource that has been assigned for forward reserve is also designated for real-time reserve, double payment is avoided by subtracting, on a megawatt-for-megawatt basis, the real-time reserve credit. These adjustments, referred to as *forward-reserve energy obligation charges*, were $1.11 million during the Reporting Period, leaving a net of $1.06 million in real-time reserve revenues. Table 14 shows real-time reserve credit payments by month.

[11] Real-time reserve pricing is possible in all hours; forward-reserve obligations are for weekday on-peak hours only.

Table 14: Real-Time Reserve Credits and Forward-Reserve Obligation Charges

	FORWARD RESERVE OBLIGATION CHARGE	REAL TIME CREDIT
February-07	$0	$132,290
March-07	-$35,590	$150,482
April-07	-$254,234	$561,811
May-07	-$426,301	$807,643
June-07	-$64,229	$73,847
July-07	-$25,375	$26,248
August-07	-$300,082	$415,201

8 Demand Response Reserves Pilot Program

The ISO is currently running the Demand Response Reserve Pilot Program, a project to assess the feasibility of including small demand response resources in the reserve markets. The goals of the project are to:

- Demonstrate whether customer loads can reliably provide Ancillary Service Market products, specifically 30-minute Operating Reserve and 10-minute non-synchronized reserve services;[12]
- Determine the level and type of control room communications, dispatch, metering and telemetry sufficient for load resources providing reserve services; and
- Identify and evaluate lower cost communications and telemetry solutions that meet control room requirements and are more suitable for demand response reserve resources.

The ISO enrolled demand resources in the pilot project for periods corresponding with the forward reserve auction periods, as shown in Table 15. The enrolled resources are activated for reserve 21 times per period to test their response. The response level has been consistent across the study periods.

Table 15: Demand Response Reserve Pilot, Participating Resources

Reserve Period	Number of Resources	Total ICAP MW of Resources
Winter 2006-07	52	22.460 MW
Summer 2007	92	38.138 MW

The ISO is continuing with the demonstration phase of the project, while simultaneously assessing suitable solutions to metering and telemetry costs and other implementation issues. The project is still in an early stage, and the ISO will include updates on it in future reserve reports.

[12] Demonstration to be based upon analysis of actual response data. NPCC now allows DR to provide synchronized reserves.

9 Conclusions and Recommendations

With the completion of three forward reserve auctions, and 10 months of Forward Reserve Market real-time reserve pricing operation, several trends have emerged.

- Overall, participation in the auctions has increased. In the first forward reserve auction, a total of 2,659 MW were offered. In the second auction, this decreased to 2,403 MW, but in the most recent auction, 3,029 MW were offered. However, offers in SWCT and rest-of-system TMOR decreased.

- Transmission improvements in the NEMA zone allowed the lowering of the reserve requirement for that zone in the most recent forward reserve auction and resulted in a more competitive local market. The auction cleared below the auction price cap for the first time.

- Forward reserve requirements for SWCT and CT were not met in any of the three auctions. The persistent shortage in SWCT and CT represents an issue that needs further evaluation since there are insufficient offers for real market clearing. In the Winter 2007/2008 auction, there were offers from only four participants in Connecticut and four in SWCT (one of these participants offered reserve capacity in both zones).

- The ISO will also continue to monitor offer behavior and clearing prices in the Rest-of-System Zone. Clearing prices increased significantly in the Summer 2007 auction, and declined only slightly in the Winter 2007/2008 auction. However, the higher prices appear to be attracting more participation which may result in moderating prices over time.

- The once-a-month method for setting the forward reserve threshold price at times results in threshold prices that are significantly higher or lower than LMPs. When the threshold price is too low compared to input fuel costs and LMPs, forward reserve units may be dispatched for energy. When the threshold price is too high, participants may have difficulty offering above the threshold price without violating energy offer mitigation screens.

- Real-time reserve pricing has generally performed as expected. The real-time reserve prices reflected actual supply conditions and system operational requirements. There were positive reserve prices during periods of redispatch and scarcity.

- The frequency with which operators needed to bind the proxy limit in Connecticut during the Reporting Period suggests that the $50/MWh local TMOR RCPF may be too low to provide economic second contingency protection within that reserve zone. There were positive reserve prices in the CT reserve zone on 23 days; the proxy limit was activated on 11 of these days. The ISO will continue to monitor this issue.

- There were very few intervals with positive real-time reserve prices in the NEMA zone that were not cascaded from system reserve prices. Recent transmission improvements in the NEMA zone allow local requirements to be met with system resources most of the time.

- Some generators that had been committed by the ISO for reliability prior to the implementation of the new Forward Reserve Market were designated as forward reserve resources. Although most of these generators had been committed for reliability only infrequently and received small amounts of NCPC payments, this contributed to a small decline in second contingency and VAR NCPC payments in the CT and NEMA load zones. However, for the reserve markets to have a significant impact on NCPC payments, the markets must be successful in attracting investment in new reserve-capable resources.

- The ISO's performance capping program has been effective in identifying non-performing fast-start resources. Because claimed 10-minute and claimed 30-minute capability that was not actually available has been removed from the pool of fast-start resources, the remaining generators identified as fast-start are reliable. The ISO will continue to monitor claimed 10-minute and claimed 30-minute capability, and incorporate the results into areas of operations and market design that rely on fast-start capability.

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