ISO NEW ENGLAND *The people behind New England's power.*

Quarterly Market Report

Q2 2003

ISO New England Inc.

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1. Overview of the Report

The Quarterly Market report of ISO New England (ISO-NE or the ISO) provides an overview of the market's performance for the second quarter of 2003. NEPOOL Market Rule 1, Appendix A, Section 11.2.2 requires the publication of a quarterly report to federal and state agencies with jurisdiction over wholesale electricity markets. This report, the first under Standard Market Design (SMD), encompasses the four-month period March 1, 2003 (implementation of SMD) through June 30, 2003. After this initial report, quarterly reporting will coincide with calendar quarters. In this report, comparisons to the analogous time period in prior years, if not exactly the same time period, are noted.

The report is organized as follows:

- **Overview of the Markets** – A high level summary of the events of the quarter in New England's wholesale electricity markets.

- **Wholesale Electricity Markets: Key Facts and Figures** – Summary statistics on Locational Marginal Pricing (LMP) for the New England energy market, both Day-Ahead (DA) and Real-Time (RT) with comparisons across load zones, the Regulation Market, Installed Capacity (ICAP) Market, Operating Reserve Credits (ORC) payments, the Financial Transmission Rights (FTR) Auctions, and Load Response Programs.

- **Market Performance**

    - Monthly and quarterly averages of LMP and its components, and an analysis of the LMPs at the nodes comprising the Hub price, a key reference point for the markets

    - Review of the Regulation market

    - Review of ORC payments, including Reliability Must Run Agreement (RMR) payments during the quarter

    - Review of the ICAP market

    - Results of FTR auctions

    - Load Response Program Activity

- **Market Analysis** – A longer-term perspective on key aspects of New England's electricity markets, including:

    - Historical quarterly prices

    - An analysis of the "All-In" Price of Wholesale Electricity

    - Analysis of fuel prices – the key variable cost underlying electricity generation

    - Comparison of New England's wholesale prices with those of other deregulated power markets

- Analysis of the generating units that set the marginal price in these markets
- Relationships between supply, demand and price
- Analysis of market concentration measures

♦ **Load and Supply Conditions –** A discussion and presentation of patterns of peak demand for electricity, monthly energy, and the weather conditions for the quarter, including:

- Electricity consumption and weather data for the system and each load zone
- Cleared DA demand as it relates to actual (i.e., RT) demand
- Pattern of electricity flows on external and internal transmission interfaces
- A presentation of constrained transmission interfaces during the period

♦ **Market Monitoring and Mitigation Activity –** A review of activity in this area during the quarter

♦ **Generator Unit Availability –** A review of the performance and availability of New England's generators during the quarter, including:

- Overall Availability of Generators
- Availability vs. Demand
- Types of unit outages and components of availability

♦ **Administrative Price Corrections**

♦ **FERC Filings and Market Rule Changes**

2. Overview of the Markets

On March 1, 2003, ISO New England (ISO-NE) successfully implemented Standard Market Design (SMD). 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 redesign 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.

Thus far, wholesale electricity prices experienced in New England under SMD have been consistent with the cost of fuel and with other wholesale electricity markets in the Northeast. Immediately prior to implementation, there was a dramatic increase in natural gas prices. This increase in natural gas prices added volatility and caused a corresponding general increase in electricity prices for both the Day-Ahead (DA) and Real-Time (RT) electricity markets relative to the prices prior to SMD implementation. Since the end of March, the fall in gas prices has contributed to a corresponding fall in wholesale electricity prices.

Overall, zonal prices in the DA and RT markets under SMD have demonstrated remarkable convergence. The slight premium in the DA market is consistent with the results of other multi-settlement markets in the Northeast. Instances of congestion, which result in price separation between zones in both the DA and RT markets, were relatively few during the quarter. This was due in part to relatively light levels of system load during the March through June timeframe.

Prior to the implementation of SMD, another feature of the new marketplace – Financial Transmission Rights (FTRs) auctions – was implemented. FTRs help market participants reduce their exposure to congestion in the DA market. The initial auctions of FTRs for the months of March through June were successfully implemented with no major issues. The monthly auctions experienced increasing levels of participation, as experience with locational prices increased, assisting bidders in better assessing the value of FTRs.

Generator availability during the quarter was somewhat lower than in previous months, reflective of high levels of planned maintenance during the spring period. Overall, availability continues to improve, however certain months have experienced a slight increase in outages.

During 2002, ISO-NE and NEPOOL received approval for new Load Response Programs from the Federal Energy Regulatory Commission (FERC) that, with the exception of the proposed Day Ahead Demand Response Program, were implemented on March 1, 2003. The FERC approved two RT demand response programs (mandatory interruption) and two voluntary RT price response programs for inclusion within SMD. As of June 30, 2003, over 220 end-use customers were enrolled in these programs, comprising over 330 MW of potential load relief to the system, approximately double the amount of relief available last year.

3. Wholesale Electricity Markets: Key Facts and Figures

A fundamental change to wholesale electricity markets in New England with the implementation of SMD is the movement from one region-wide clearing price under the interim (May 1999 – February 2003) markets to a system of Locational Marginal Pricing (LMP). LMPs result from the application of a linear programming process which minimizes total energy costs for the entire New England region, subject to a set of constraints reflecting physical limitations of the power system. In the accounting process, the three components of LMPs are separated:

LMP ($/MW) = Energy component + Marginal Loss component + Congestion component

LMPs in both the DA and RT markets are influenced by a variety of factors, including energy demand, energy offers, virtual supply offers and bids, operating characteristics of generators, reserve requirements, the commitment of generating units, transmission network topology, transmission constraints, and external transactions.

In addition to the eight pricing zones created in New England for SMD (one for each state; three in Massachusetts), a new pricing location was also created. The Internal Trading Hub (or simply 'Hub') price is a simple average of prices at 32 locations near the geographic center of New England. These locations were chosen because they will generally not be prone to congestion under normal dispatch conditions, and price movements at these locations are representative of the entire New England system. The ISO publishes this price to facilitate bilateral contracting between market participants and to provide a reference point for other LMPs, both inside and outside the New England Control Area.

3.1. Summary LMP Statistics for the Quarter

3.1.1. Quarterly Average RT vs. DA Price

Table 1 below shows the quarterly average LMP as well as its minimum, maximum, and standard deviation at the Hub and the eight load zones. The price at each location is also compared to that at the Hub, and the RT and DA prices and standard deviations are compared.

For the quarter, the average DA LMPs were, on the whole, similar to RT LMPs at each location and between locations. One notable exception is the Maine Load Zone where DA and RT LMPs averaged 8-10% lower than the Hub price, primarily due to the effect of marginal losses. Overall, the RT market was more volatile than the DA market at the Internal Hub and in all eight load zones.

Table 1 – Summary LMP Statistics for the Quarter, All Hours

Location	LMP ($/MWh)						As % of Hub - DA	As % of Hub - RT	RT as % of DA	DA Std Dev	RT Std Dev	RT SD / DA SD
	Avg DA	Avg RT	Min DA	Min RT	Max DA	Max RT						
Internal Hub	$53.30	$52.53	$10.87	$0.00	$148.68	$398.60	100%	100%	99%	$18.98	$25.21	1.33
Maine Load Zone	$49.19	$47.49	$9.99	$0.00	$212.89	$367.81	92%	90%	97%	$21.26	$22.72	1.07
New Hampshire Load Zone	$52.22	$51.11	$10.61	$0.00	$146.17	$389.02	98%	97%	98%	$19.11	$24.11	1.26
Vermont Load Zone	$53.84	$52.55	$2.77	$0.00	$149.30	$388.90	101%	100%	98%	$19.87	$24.99	1.26
Connecticut Load Zone	$53.99	$53.19	$11.02	$0.00	$244.42	$393.44	101%	101%	99%	$20.72	$25.60	1.24
Rhode Island Load Zone	$52.05	$51.75	$10.78	$0.00	$142.42	$394.85	98%	99%	99%	$18.15	$24.75	1.36
SEMASS Load Zone	$52.23	$51.74	$10.71	$0.00	$132.84	$392.85	98%	98%	99%	$18.08	$24.77	1.37
WCMASS Load Zone	$53.30	$52.59	$10.89	$0.00	$148.52	$397.53	100%	100%	99%	$18.89	$25.21	1.33
NEMA/Boston Load Zone	$53.55	$52.15	$10.66	$0.00	$215.00	$397.63	100%	99%	97%	$21.40	$25.66	1.20

3.1.2. Quarterly On-Peak and Off-Peak LMPs

Bilateral contracts utilize the hours between 7:00 a.m. and 11:00 p.m. on non-holiday weekdays as "on-peak" hours in the New England Control Area. Conversely, from 11:00 p.m. to 7:00 a.m. on weekdays, and all day on Saturdays, Sundays, and holidays represent the "off-peak" period. Demand for electricity is generally higher during the on-peak periods and lower in the off-peak periods, driven primarily by commercial and industrial sector use.

The relationship between DA and RT LMPs was remarkably similar in both the on and off-peak periods, with RT prices averaging about 2% lower than DA prices (except ME, RI, and SEMA for on-peak). During the quarter, DA and RT LMP averaged about 25% higher in the on-peak period than in the off-peak period. This was driven by large price changes during periods of excess generation. DA off-peak standard deviations were lower than DA On-Peak. The standard deviation for the RT market averaged nearly 17% greater in the off-peak period versus the on-peak period and, further, when normalized for their respective means (i.e., coefficient of variation), off-peak volatility was 46% greater. Table 2 and Table 3 below summarize the on/off peak pricing for the quarter.

Table 2 – Summary LMP Statistics for the Quarter, On-Peak Hours

Location	LMP ($/MWh)						DA as % of Hub	RT as % of Hub	RT as % of DA	DA Std Dev	RT Std Dev	RT SD / DA SD
	Avg DA	Avg RT	Min DA	Min RT	Max DA	Max RT						
Internal Hub	$59.79	$59.07	$34.77	$19.29	$148.68	$269.66	100%	100%	99%	$19.09	$22.50	1.18
Maine Load Zone	$54.61	$51.89	$32.00	$18.06	$212.89	$217.01	91%	88%	95%	$23.62	$19.54	0.83
New Hampshire Load Zone	$58.78	$57.13	$34.04	$19.06	$146.17	$217.29	98%	97%	97%	$19.70	$20.71	1.05
Vermont Load Zone	$60.91	$58.92	$35.04	$19.49	$149.30	$219.30	102%	100%	97%	$20.43	$22.07	1.08
Connecticut Load Zone	$61.06	$60.45	$35.23	$19.48	$244.42	$245.11	102%	102%	99%	$22.45	$23.14	1.03
Rhode Island Load Zone	$57.96	$58.11	$34.46	$18.92	$142.42	$270.26	97%	98%	100%	$18.07	$22.04	1.22
SEMASS Load Zone	$58.37	$58.10	$34.24	$18.97	$132.84	$276.85	98%	98%	100%	$17.82	$22.12	1.24
WCMASS Load Zone	$59.76	$59.20	$34.82	$19.38	$148.52	$266.51	100%	100%	99%	$18.93	$22.48	1.19
NEMA/Boston Load Zone	$60.55	$58.53	$34.14	$19.26	$215.00	$375.93	101%	99%	97%	$23.39	$23.64	1.01

Table 3 –Summary LMP Statistics for the Quarter, Off-Peak Hours

Location	LMP ($/MWh)						DA as % of Hub	RT as % of Hub	RT as % of DA	DA Std Dev	RT Std Dev	RT SD / DA SD
	Avg DA	Avg RT	Min DA	Min RT	Max DA	Max RT						
Internal Hub	$47.67	$46.85	$10.87	$0.00	$124.38	$398.60	100%	100%	98%	$16.99	$26.05	1.53
Maine Load Zone	$44.47	$43.68	$9.99	$0.00	$160.21	$367.81	93%	93%	98%	$17.69	$24.54	1.39
New Hampshire Load Zone	$46.53	$45.88	$10.61	$0.00	$122.27	$389.02	98%	98%	99%	$16.60	$25.60	1.54
Vermont Load Zone	$47.71	$47.03	$2.77	$0.00	$124.89	$388.90	100%	100%	99%	$17.16	$26.04	1.52
Connecticut Load Zone	$47.85	$46.89	$11.02	$0.00	$122.97	$393.44	100%	100%	98%	$16.85	$25.96	1.54
Rhode Island Load Zone	$46.93	$46.23	$10.78	$0.00	$119.70	$394.85	98%	99%	99%	$16.60	$25.64	1.54
SEMASS Load Zone	$46.91	$46.22	$10.71	$0.00	$117.44	$392.85	98%	99%	99%	$16.56	$25.61	1.55
WCMASS Load Zone	$47.69	$46.86	$10.89	$0.00	$124.25	$397.53	100%	100%	98%	$16.97	$26.04	1.53
NEMA/Boston Load Zone	$47.47	$46.61	$10.66	$0.00	$147.62	$397.63	100%	99%	98%	$17.36	$26.06	1.50

3.1.3. DA and RT Prices at the Hub

The ISO has defined a Hub at which LMPs are calculated for use by Participants. The Hub is intended to provide a common point for commercial energy trading by Participants. The Hub can be used as a settlement location in the DA Energy Market for Increment Offers and Decrement Bids in the DA Energy Market and the RT Energy Market for Internal Bilateral Transactions. Aggregating a representative selection of Nodes within the NEPOOL Control Area reduces price volatility and provides a price signal that is more predictable.

The Nodes that make up the Hub were chosen such that the difference in the Congestion Component of the LMPs at these Nodes is likely to be minimal, which will generally result in stable, more predictable pricing. The Nodes within the Hub are defined in Table 4 below. Hub prices are the simple average LMPs of the specified Nodes constituting the Hub and these LMPs are calculated for both the DA Energy Market and the RT Energy Market.

Table 4 – Nodes Comprising the New England Hub

345 kV	230 kV	115 kV	115 kV	115 kV	115 kV
Northfield	Pratts Jct.	Ludlow	Bloomingdale	Wendell Depot	Ayer
Ludlow		Palmer	Nashua	Wyman-Gordon	Sandy Pond
Carpenter Hill		W. Charlton	Greendale	Vernon Hill	Millbury #2
Sandy Pond		Carpenter Hill	Rolfe Ave./ Shrewsbury	E. Main St.	Thorndike
Millbury #3		N. Oxford	W. Boylston/ Boylston	Northborough Rd.	Little Rest
		Webster St.	Wachusetts	Paxton	
		Barre	Pratts Jct.	Sterling	

On-peak LMPs at the Hub averaged $59.79 in the DA market and $59.07 in the RT market during the quarter. Off-peak LMPs averaged $47.67 in the DA Market and $46.85 in the RT market. This is shown in Figure 1 below.

Figure 1 – DA and RT Hub Prices for the Quarter

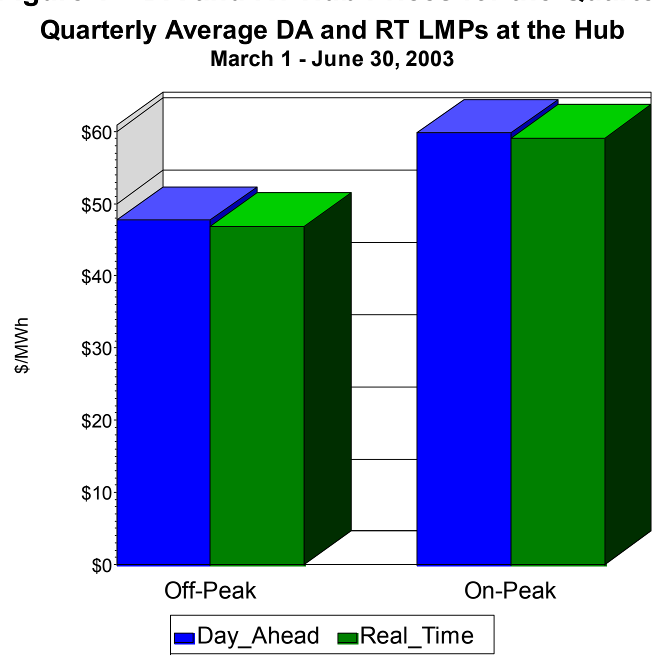
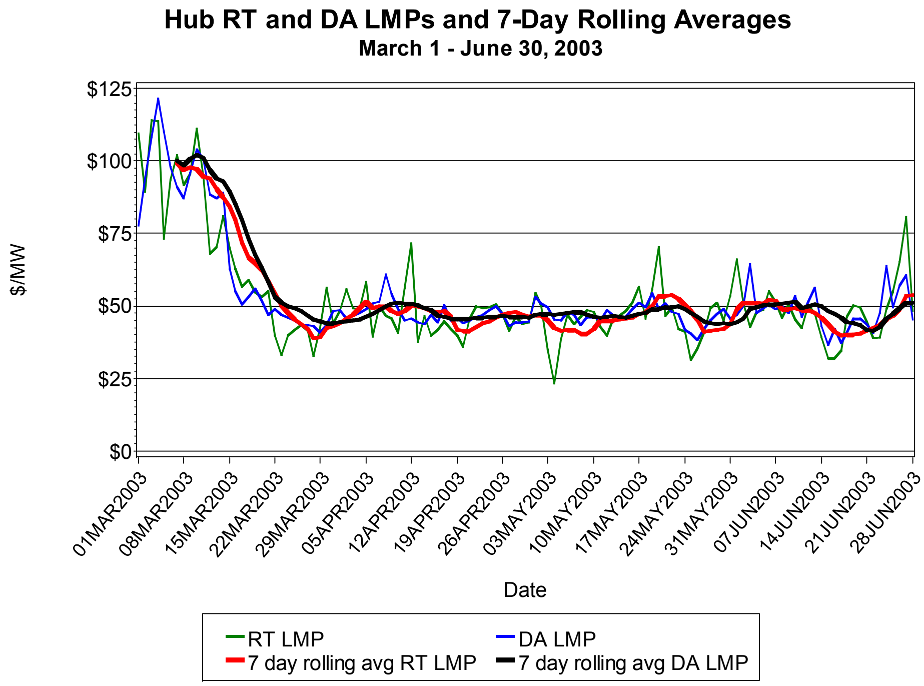


Figure 2 below shows the daily average DA and RT LMPs at the Hub during the quarter, along with the 7-day rolling average. Notable in this figure are the high LMPs associated with high input fuel prices experienced at SMD inception. Also notable is the high degree of convergence between the DA and RT prices, noticeable in both Figure 1 and Figure 2.

Figure 2 – Hub RT and DA LMP with Rolling Averages



3.2. Regulation Market

Regulation is generation under ISO control that automatically tracks minute-to-minute changes in load. Approximately one-quarter of the generators in New England are capable of providing regulation service, yet the ISO typically requires no more than 12 generators to actually provide regulation service at any one time.

The Regulation operating requirement is defined using MW as the unit of measurement, and the Regulation clearing price is expressed in $/MWh. The Regulation clearing price is calculated in advance of the dispatch day. It is set by the resource with the highest combined Regulation offer plus estimated unit-specific Opportunity Costs. There may be additional opportunity costs in real time. Total Regulation payments include opportunity costs and the Regulation Clearing Price times the Regulation MWh provided. The regulation 'service' payment in the Interim Market, which compensated the load-following capability actually delivered by a Resource, was eliminated under SMD. RT regulation opportunity cost credits totaled approximately $2.6 million for the quarter.

3.2.1. Quarterly Average Regulation Market Clearing Prices

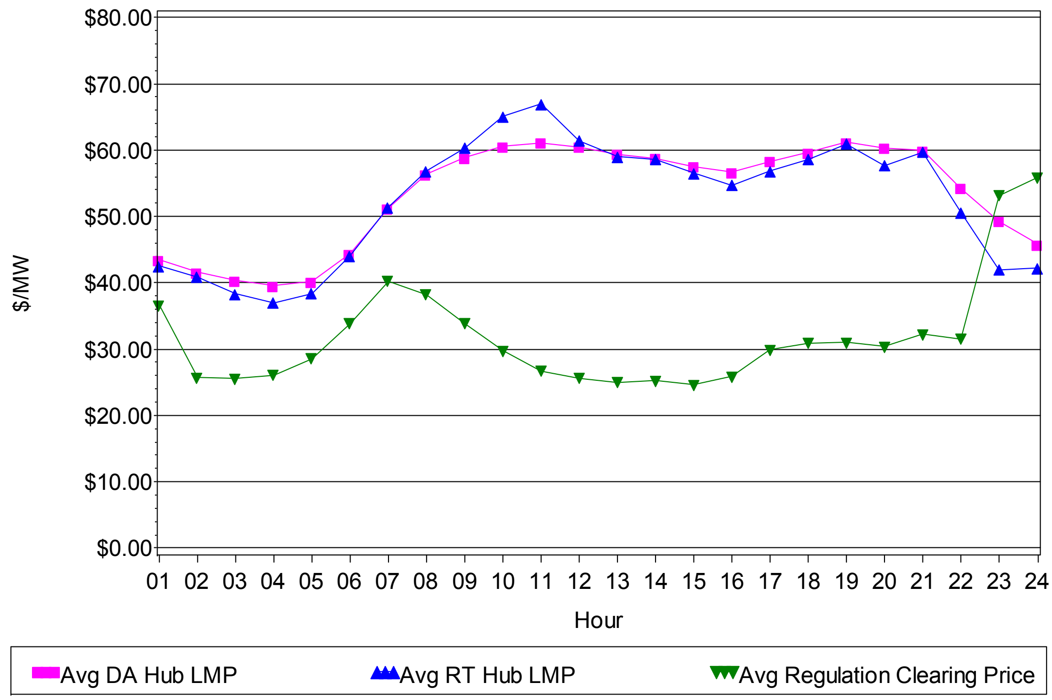
Table 5 below shows summary statistics for the Regulation clearing price for the quarter and Figure 3 compares the Regulation clearing price with the Hub DA and RT LMP on an average hourly basis for the quarter. Regulation market clearing prices averaged $31.95/MWh, compared to the DA LMP of $53.30/MWh at the Hub. Note that Regulation offers must be less than or equal to $100/MWh.

Table 5 –Regulation Clearing Prices for the Quarter

Avg. Reg. Price	Median Reg. Price	Min. Reg. Price	Max. Reg. Price	Std Dev Reg. Price
$31.95	$22.55	$0.00	$678.43	$34.39

Figure 3 – Average Hourly Regulation Prices and Hub LMPs

March 1 - June 30, 2003



3.3. Operating Reserve Credit and Reliability Must Run Agreement Payments

Operating Reserve Credit (ORC) payments are made to eligible generators who have a shortfall between their revenue (based on clearing prices in the energy and regulation markets), and their offer (based on their energy offer, start-up fee, and no-load fee). Certain external transactions are also eligible for ORC. On a daily basis, eligible resources may receive ORC payments if the ISO commits them for economic, VAR support, or daily reliability must-run reasons (daily RMR.)

Additionally, certain resources receive contractual compensation for the reliability services they provide in areas of the system that, absent any transmission improvements or the addition of resources, are needed to maintain reliability. These RMR Agreements are discussed in more detail in Section 3.3.3.

3.3.1. ORC Payments for the Quarter, DA and RT Markets

ORC payments in the second quarter totaled $5,062,488 in the DA Market and $9,331,129 in the RT Market[1]. ORC data is subject to revision during the Settlement process, and as such, these values are preliminary.

DA ORCs are allocated to and charged to participants in proportion to their total cleared demand bids and decrement bids for the operating day. RT ORCs are allocated to and charged to participants in proportion to RT deviations from DA schedules during the operating day. Economic and VAR ORC are allocated across the entire Pool while Participants within the relevant reliability region pay RMR ORC. Table 6 summarizes the three types of ORC payments, associated MWh, and $/MWh for the month.

Table 6 – ORC Payments by Type for the Quarter

	Economic			RMR			VAR		
Market	ORC Paid	ORC (MWh)	$/MWh	ORC Paid	ORC (MWh)	$/MWh	ORC Paid	ORC (MWh)	$/MWh
Day Ahead	$1,692,928	279,920	$6.05	$115,086	15,539.0	$7.41	$3,254,474	107,398	$30.30
Real Time	$4,917,298	414,204	$11.87	$3,841,789	127,025.0	$30.24	$572,042	26,850	$21.31

3.3.2. RMR ORC Payments for the Quarter, DA and RT Markets

Table 7 presents the RMR ORC information for the DA and RT markets for the quarter. The vast majority of these payments were made in the RT market, totaling $3.8 million.

Table 7 – RMR ORC Payments for the Quarter

Market	ORC Payments	ORC MWh	$/MWh
DA Total	**$115,085.40**	**15,539.0**	**$7.41**
RT Total	**$3,840,338.04**	**126,931.4**	**$30.26**
Grand Total	**$3,955,423.44**	**142,470.4**	**$27.76**

3.3.3. RMR Agreement Payments

In addition to ORC payments, monthly payments are made to certain generators with Reliability Must Run (RMR) agreements. These agreements reflect a determination by ISO-NE that these resources are needed to maintain transmission system reliability or to provide second contingency coverage and will be required to run out-of-economic-merit-order. Resources under RMR agreements are required to base their energy offers on their short-run variable cost. Payments made to generators under RMR agreements are distinct from RMR ORC payments. Contract RMR payments to resources for March through June 2003 totaled $12.1 million.

[1] Payments made to Special Constraint Resources (SCR) are not included in these totals.

3.4. ICAP Market

ISO-NE conducts a supply auction at the middle of each month to facilitate the transaction of Installed Capacity (ICAP.) Installed capacity must be held or procured by load serving entities to satisfy their capacity obligations for the following month. The market commodity is now referred to as Unforced Capacity (UCAP). UCAP differs from ICAP in that UCAP reflects the probability that a resource will be unavailable to serve load due to forced outages.

If, after the supply auction, ISO-NE determines that any load serving participant has failed to procure sufficient UCAP to cover its monthly requirement, ISO-NE conducts a deficiency auction. Participants are required to offer any UCAP in excess of their UCAP requirement in the deficiency auction. If a participant is still deficient after that auction, the participant must pay a deficiency charge.

3.4.1. ICAP Auction Clearing Prices by Month

Most ICAP requirements are met through either self-supply or bilateral contracts, and small amounts are traded through the supply and deficiency auctions. Table 8 below shows the clearing prices for the ICAP auctions during the quarter, 3 months of which represents the SMD period.[2] A large amount of MW offered into the Deficiency Auction at $0 are responsible for the $0 Clearing Price. Also, the significant increase in Cleared MW seen in June did not persist past that month, and is likely a one-time occurrence.

Table 8 – ICAP Market Clearing Prices for the Quarter

	Supply Auction		Deficiency Auction[3]	
Obligation Month	Cleared (MW)	Clearing Price ($/MW-Month)	Cleared (MW)	Clearing Price ($/MW-Month)
Mar-03	N/A	N/A	44.208	$4,870.00
April-03	310.310	$400.00	204.271	$0.00
May-03	1,125.497	$150.00	15.448	$0.00
June-03	780.545	$200.00	1,206.563	$0.00

3.5. FTR Auction

Under SMD, load pays for electricity based on the Locational Marginal Price (LMP) at each of the load zones. When transmission congestion occurs, LMPs will vary throughout the power grid. This price separation will cause the ISO to collect more revenue from load in congested areas than it will pay to generators supplying electricity to those areas from areas experiencing lower LMPs. The excess collection is called "congestion revenue."

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[2] Due to data requirements that support the SMD market, April 2003 was chosen as the first capability month.

[3] Prior to the April 2003 Obligation Month, the Capacity Market was operated on a different basis. Participant ICAP deficiencies were charged at a uniform deficiency rate of $4,870/MW-month.

To hedge, or protect, against the adverse impacts of having to pay higher LMPs due to congestion, market participants can bid for the rights to receive a share of the congestion revenue. These rights are called Financial Transmission Rights, or FTRs. Essentially, FTRs are financial entitlements to the Day-Ahead Price Congestion Component differences for the associated receipt and delivery points. They do not represent a right for physical delivery of power.

FTRs can be acquired in two ways:

(1) FTR Auction – The ISO conducts periodic auctions to allow Eligible FTR Bidders to acquire FTRs. The auction also allows FTR Holders an opportunity to sell FTRs that they are currently holding.

(2) Secondary Market - The FTR secondary market is one in which FTR Holders and other entities that have acquired FTRs may sell FTRs on a bilateral basis. Bilateral trading of auctioned FTRs may be accomplished through an ISO-administered bilateral trading system, or may be done independently.

3.5.1. FTR Auction Summary

In each of the first four months of SMD, the entire transmission capacity of the NEPOOL system was offered in the monthly auctions. The first Long-Term FTR Auction will be conducted for the period October through December 2003. In that auction, fifty percent of the capacity of the NEPOOL transmission system will be available to eligible FTR bidders for the period, with the remaining transmission capacity made available in each of the monthly FTR Auctions. Additionally, holders of long-term FTRs may offer them for sale in the monthly auctions.

Because the first long-term FTR auction (for the period October – December 2003) will not be held until September, each of the first four monthly auctions featured only "buy" activity. The number of bidders ranged between 27 and 41 and they made bids that totaled $24,500,000 (with over $5.5 million awarded) over the four-month period.

Table 9 – FTR Auction Volume Summary

Month	Bidders	Bid MW	Cleared MW	Bid $	Awarded $	Bids	Cleared
Off Peak Results							
March	27	8,375.1	7,145.8	$671,598.99	$48,231.62	200	180
April	36	13,453.1	9,657.5	$499,301.46	$8,144.40	277	210
May	41	13,508.1	7,503.7	$935,717.62	$104,130.54	389	204
June	34	15,843.0	9,207.7	$1,175,912.56	$315,518.36	880	384
On Peak Results							
March	27	20,308.3	10,761.9	$4,168,085.24	$1,007,040.09	511	347
April	36	17,031.7	10,917.8	$3,062,750.06	$620,080.29	437	305
May	41	22,388.5	11,335.1	$5,460,508.03	$1,287,611.46	658	316
June	34	30,331.1	14,800.9	$8,600,346.04	$2,188,428.67	1,062	395
Total Auction Results							
March	27	28,683.4	17,907.7	$4,839,684.23	$1,055,271.71	711	527
April	36	30,484.8	20,575.3	$3,562,051.52	$628,224.69	714	515
May	41	35,896.6	18,838.8	$6,396,225.65	$1,391,742.00	1,047	520
June	34	46,174.1	24,008.6	$9,776,258.60	$2,503,947.03	1,942	779
Quarterly Totals							
		141,238.9	81,330.4	$24,574,220.00	$5,579,185.43	4,414	2,341

3.5.2. FTR Auction Clearing Prices by Month, Hub and Zones

Table 10 below shows the value assigned by the FTR auction to the paths from the Hub to each of the load zones during the quarter. FTR bids are expressions by bidders of the amount (in $/MW-month for the auction period) they are willing to pay for the FTR. The auction optimizes the auction's total value using a linear programming model and resulting in an indicative price at every location.

Path clearing prices (source price minus sink price) that are negative indicate that a cleared bid to buy in that direction (e.g., Hub to New Hampshire Zone) have resulted in a *payment* to the winning participants in that amount for each MW FTR that was awarded. Conversely, positive path clearing prices indicate that a cleared bid to buy in that direction (e.g., Hub to NEMA/Boston Zone) have resulted in a *charge* to the winning participants in that amount for each MW FTR that was awarded.

On-Peak FTRs from the Hub to the NEMA/Boston Load Zone are the only ones that were positively priced during the entire quarter. Holders of those FTRs would be eligible for Congestion Credit Payments if the DA LMP were higher than the Hub in that load zone. By contrast, FTRs from the Hub to Maine, New Hampshire, SEMASS, and Rhode Island load zones have been valued negatively – those Participants whose bids cleared on those paths were consistently paid to take them, primarily because potential congestion in that direction is unlikely.

Table 10 – Hub to Zone FTR Clearing Prices

Source Location Name	Sink Location Name	$/MW-Month			
		March	April	May	June
Off-Peak					
Hub	CONNECTICUT	0.01	0.01	2.82	-17.44
Hub	MAINE	-49.98	-3.87	-0.84	-107.52
Hub	NEMASSBOST	0.81	0.18	18.97	3.28
Hub	NEWHAMPSHIRE	-0.30	0.00	-0.83	-57.76
Hub	RHODEISLAND	0.01	0.00	-18.62	-19.65
Hub	SEMASS	0.01	0.00	-16.03	-20.00
Hub	VERMONT	-0.08	0.00	2.88	-14.21
Hub	WCMASS	0.02	0.00	5.64	-6.38
On-Peak					
Hub	CONNECTICUT	-2.74	-40.55	61.61	61.31
Hub	MAINE	-439.14	-21.12	-7.06	-546.26
Hub	NEMASSBOST	50.76	197.12	285.32[4]	184.31
Hub	NEWHAMPSHIRE	-145.87	-11.23	-5.42	-247.85
Hub	RHODEISLAND	-1.62	-38.13	-102.52	-36.13
Hub	SEMASS	-1.26	-34.00	-91.61	-20.00
Hub	VERMONT	-43.74	-26.36	70.35	-51.63
Hub	WCMASS	-2.34	21.12	40.33	-4.40

3.6. Load Response Programs

The ISO administers the NEPOOL Load Response Program (the "Program") for the New England wholesale electricity market. The four programs embodied in the Program are:

- Real-Time Demand Response Program (30 minute or 2 hour response)
- Real-Time Price Response Program
- Real-Time Profiled Response Program
- Day-Ahead Demand Response Program (not yet implemented)

As of June 30, 2003, 224 customer locations were enrolled in the program, comprising just over 335 MW of potential load interruption or curtailment. While the number of customer locations is similar, this potential load interruption value represents over a 100% increase from last year at this time. During the quarter, there were no implementations of the Real-Time Demand

[4] Because an FTR purchase represents a financial entitlement to a portion of the transmission system's capacity, Market Participants bid for FTRs in $/MW-month. Expressed in terms of monthly energy, the highest On-Peak FTR during the quarter ($285.32/MW-month, Hub to NEMA/Boston, May) equates to an effective purchase price of $0.85 /MWh; $285.32/336 on-peak hours in the month.

Response Program because the requisite reliability criteria (i.e., implementation of NEPOOL Operating Procedure No. 4) was never realized. The Real-Time Price Response Program – triggered by forecasts of LMP greater than $100/MWh – was implemented 20 times during the quarter and resulted in 859 MWh of curtailed consumption – a little over 4.5 MWh in each hour the program was implemented. The relatively modest response is likely a function of the relatively modest LMPs during the hours in which the program was activated. A detailed program evaluation is being conducted, the results of which will be filed with the FERC by the end of the year. The composite statistics for the quarter are shown below in Table 11. Load Response is discussed in more detail in Section 4.5 of this report.

Table 11 – MWh Curtailed Under Price Response Programs

Date	Total MWh	Total Potential MWh	% of Total Potential	Avg Hub LMP	Event start	Event end	Duration (hours)
03/03/03	12.05	1,563.65	0.8%	$116.95	7:00	18:00	11
03/04/03	35.98	1,563.65	2.3%	$112.87	7:00	18:00	11
03/05/03	25.82	1,563.65	1.7%	$71.07	7:00	18:00	11
03/06/03	20.65	2,477.66	0.8%	$96.73	7:00	18:00	11
03/07/03	39.12	2,477.66	1.6%	$101.00	7:00	18:00	11
03/10/03	22.82	2,477.83	0.9%	$111.54	7:00	18:00	11
03/11/03	50.57	2,477.83	2.0%	$93.35	7:00	18:00	11
03/12/03	19.56	2,477.83	0.8%	$67.69	7:00	18:00	11
03/13/03	72.70	2,477.83	2.9%	$70.79	7:00	18:00	11
03/14/03	49.98	2,477.83	2.0%	$82.15	7:00	18:00	11
04/04/03	-	2,477.83	0.0%	$50.05	7:00	18:00	11
04/08/03	-	2,477.83	0.0%	$46.16	7:00	18:00	11
04/11/03	54.61	2,477.83	2.2%	$56.42	7:00	18:00	11
04/14/03	21.43	1,802.06	1.2%	$46.93	10:00	18:00	8
06/05/03	95.50	3,062.08	3.1%	$48.98	7:00	18:00	11
06/25/03	0.64	1,810.93	0.0%	$55.15	12:00	18:00	6
06/26/03	130.96	3,320.03	3.9%	$65.20	7:00	18:00	11
06/27/03	207.06	3,329.95	6.2%	$80.74	7:00	18:00	11
Total	859.45	42,793.94					190
Average	90.47	4,504.62	2.0%	$76.32			

4. Market Performance

This section of the report provides information about LMPs in both the Day-Ahead and Real-Time markets. The Locational Marginal Price is the cost of supplying an increment of load at a particular location. LMPs are calculated for each node as well as the eight load zones and the internal Hub in both the DA and RT markets. LMPs are made up of three components: energy, congestion and marginal loss. The energy component of an LMP is the cost of providing an additional increment of energy to the distributed market reference bus. [5] In any hour, the energy component is the same for all locations, while the congestion and marginal loss components may vary among locations. If there were no congestion and no losses, LMPs would be the same for all locations. Although the three components of the LMP are separated in the accounting process, the cost of energy at a location is the total LMP.

LMPs cannot be directly compared with the pre-SMD ECPs because of fundamental differences in the calculation of LMPs and ECPs. However, examining trends in energy prices over time is useful. In this report, the All-In price of wholesale electricity is used to compare the price of energy under the Interim Market structure and the SMD structure.

Information about the methods for calculation and settlement of LMPs can be found in NEPOOL Market Rule 1 and NEPOOL Manual 11. These documents are available from the ISO-NE web site.

4.1. Energy Market

4.1.1. Day Ahead vs. Real Time LMPs and Their Components

LMPs are made up of three components: energy, congestion and marginal loss. The energy component of an LMP is the cost of providing an additional MW of energy in the system, is the same for all locations and, absent congestion and ignoring marginal losses, is equal to the LMP.

Congestion is a component of the LMP.[6] The inclusion of congestion costs in the energy price and resulting potential price separation between locations is a key element of SMD. The dollar value of the congestion component cannot be used directly to measure the underlying cost of congestion in a location. Rather, the congestion component should be treated as an indicator of relative congestion costs between locations.

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[5] The New England reference bus is not an actual physical location. A formula that incorporates the proportion of load in the eight load zones is used to represent the reference bus in LMP calculation. Note that the reference bus is not the same as the Internal Hub.

[6] In the Interim Market, the ECP did not include congestion costs. The ECP was the uncongested marginal price for the system. Congestion costs were paid separately via congestion uplift charges during May 1999 through June 2001 and via NCPC payments for July 2001 through February 2003.

The marginal loss component of the LMP reflects how much transmission losses would change for the entire system if one additional megawatt of power were to be injected at that location. This change is the loss factor, and is related to transmission voltage and the distance between generation and load. If system losses would be reduced by an extra injection at a location, the loss factor for that location will be negative. If system losses would be increased by an extra injection at a location, the loss factor for that location will be positive. The negative of the loss factor is multiplied by the energy component to derive the marginal loss component (i.e., *marginal loss component = -loss factor * energy component*). A negative loss factor will cause the marginal loss component of the LMP to be positive, raising the LMP, while a positive loss factor will cause the marginal loss factor of the LMP to be negative, lowering the LMP. Variation in the marginal loss component among locations will cause separation of LMPs.[7]

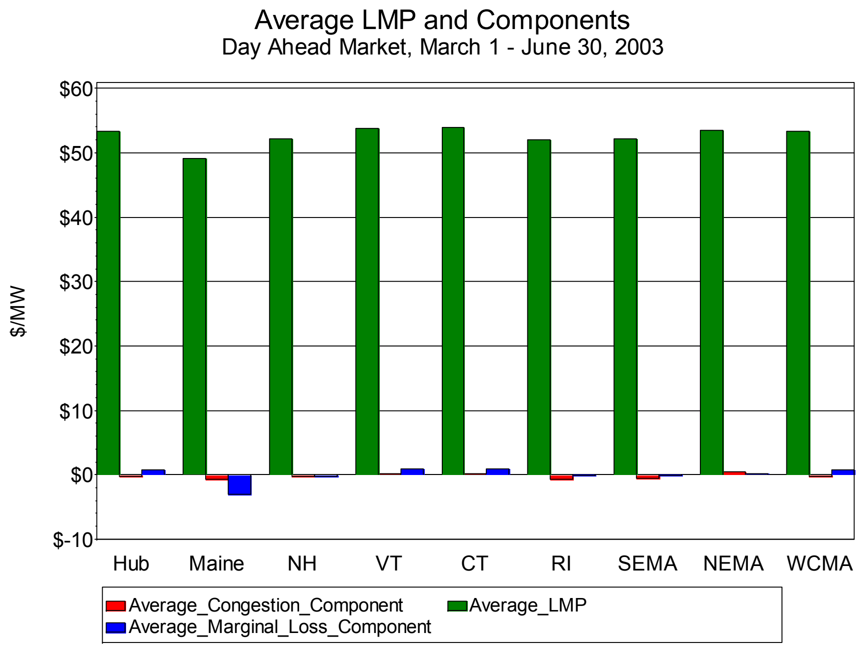
ISO-NE defines a distributed *market reference bus* to facilitate the calculation of both the loss and congestion components of LMPs. It is comprised of all nodes within the NEPOOL control area that have associated loads. Conceptually, a small increase in the output of a generator (an injection) must be balanced by a corresponding increase in consumption (a withdrawal). The balancing withdrawal is distributed proportionally to all busses with load in the system. In other words, each bus at which load is modeled is allocated its load-weighted portion of the balancing withdrawal. This approach is taken because the value of the loss sensitivity factors, and therefore the loss component of the LMP, is dependent on the location of the reference bus.

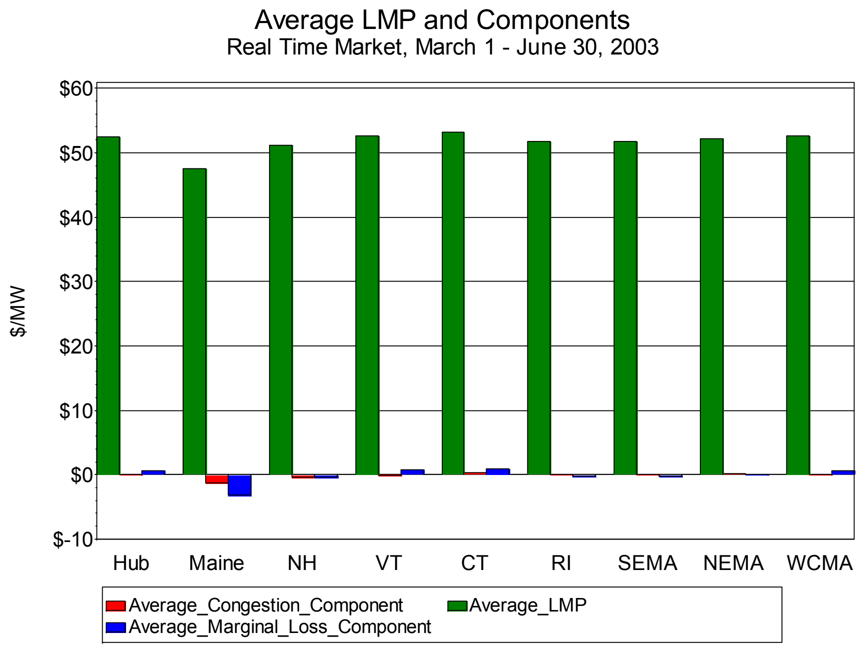
The distributed reference makes calculation of the loss factors less dependent upon the location of the reference bus. This approach promotes fairness in the calculation of the loss component of LMP, and also eliminates discontinuities in the loss and congestion component values that could arise from a reference bus that changed from one location to another with each execution of ISO-NE's dispatch model.

Figure 4 shows the quarterly average values for the LMP and components for the Hub and each load zone in the DA and RT markets. The congestion component tends to be small, while the marginal loss component was the key driver of lower overall LMPs in the Maine Load Zone.

[7] In the Interim Market, the ECP reflected the cost of transmission losses via a "penalty factor" adjustment to the bids of generating resources. For example, if the unit was far away from load, its bid price was increased, while if it was close to load, its bid price was decreased. This methodology, while differing from the current practice, still relied upon simulating the injection of a marginal increment of energy.

Figure 4 – Average LMP and Components, DA and RT Markets

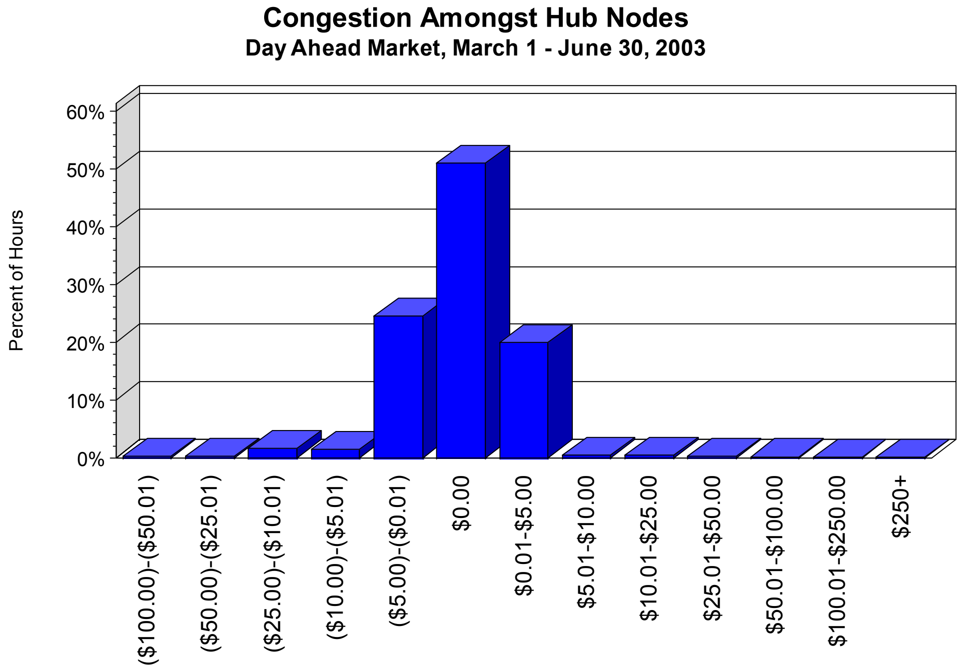


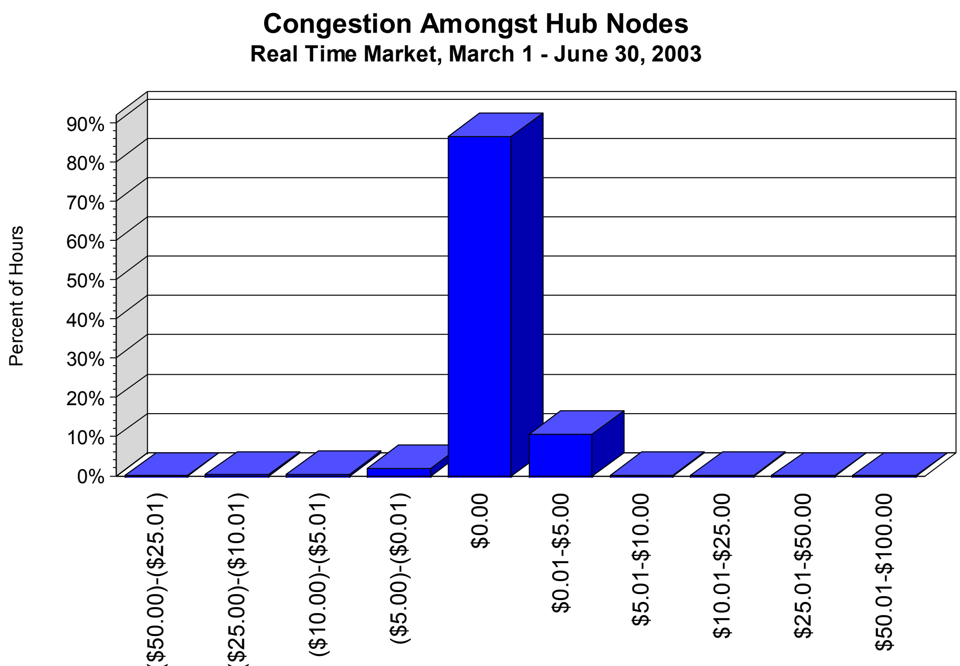


4.1.2. Hub Nodes – Quarterly Summary

In addition to zonal prices, the ISO also calculates a Hub price. The Hub LMPs are calculated as a simple average of the LMPs of the 32 nodes that comprise the Hub. Figure 5 shows congestion amongst the Hub nodes in the DA and RT market, respectively.

Figure 5 – Congestion Amongst Hub Nodes





4.2. Operating Reserve Credit (ORC) and Reliability Must Run (RMR) Payments

Operating Reserve Credit payments are made to eligible generators and certain external transactions that have a shortfall between their revenue (based on clearing prices in the energy and regulation markets), and their offer price (based on their energy offer, start-up fee, and no-load fee). ORC payments for the quarter totaled $14,272,551.[8] This figure, which is subject to resettlement, is final in this case because the 90-day resettlement process has been completed.

The following criteria are used to determine a resource's eligibility to receive ORC:

- Generators capable of providing operating reserve, replacement reserve, or meeting other eligibility requirements as outlined in Market Rule 1
- Resources that provide VAR support
- Resources that are designated as a daily RMR resource
- Generators that run to relieve local transmission constraints may receive Special Constraint Resource (SCR) ORC
- Generators that are self-scheduled are not eligible to receive ORC.

The calculation of ORC differs between resources committed in the DA market and those committed in the RT market, although the accounting for both is done on a daily basis. ORC for DA units is computed by first summing DA offer amounts, which include applicable no-load and start-up fees as well as energy costs (calculated as cleared DA MW * energy offer, for the day). Next, hourly DA values (calculated as cleared DA MW * DA LMP) are summed for the day. The daily DA value is subtracted from the daily DA offer, and the excess amount, if any, is the resource's DA ORC.

Units meeting the above criteria that are committed in the Resource Adequacy Analysis (RAA) following the close of the DA Market or are committed in the RT Market are eligible for RT ORC. The RT ORC is calculated by first summing the RT offers for the day and the RT values for the day. The following calculation is then performed: *RT Daily Offer – (RT Daily Value + DA Daily Value + DA ORC Daily Credit + RT Daily Regulation LOC)*. The resource is eligible to receive a RT ORC payment to the extent that the RT Daily offer exceeds the total of the RT and DA Daily Value, DA Daily Credit, Daily Regulation LOC and Daily Reserve Shortage Opportunity Costs.

DA ORCs are allocated to and charged to participants in proportion to their total cleared demand bids and decrement bids for the operating day. RT ORCs are allocated to and charged to participants in proportion to RT deviations from DA schedules during the operating day. Economic and VAR ORC are allocated across the entire Pool. Participants within the relevant reliability region pay RMR ORC. Table 12 summarizes the three types of ORC payments, associated MW, and $/MW for the month. Table 13 presents the RMR ORC information for each of the load zones.

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[8] Payments made to Special Constraint Resources (SCR) are not included in this total.

4.2.1. Economic, RMR, and VAR ORC Payments

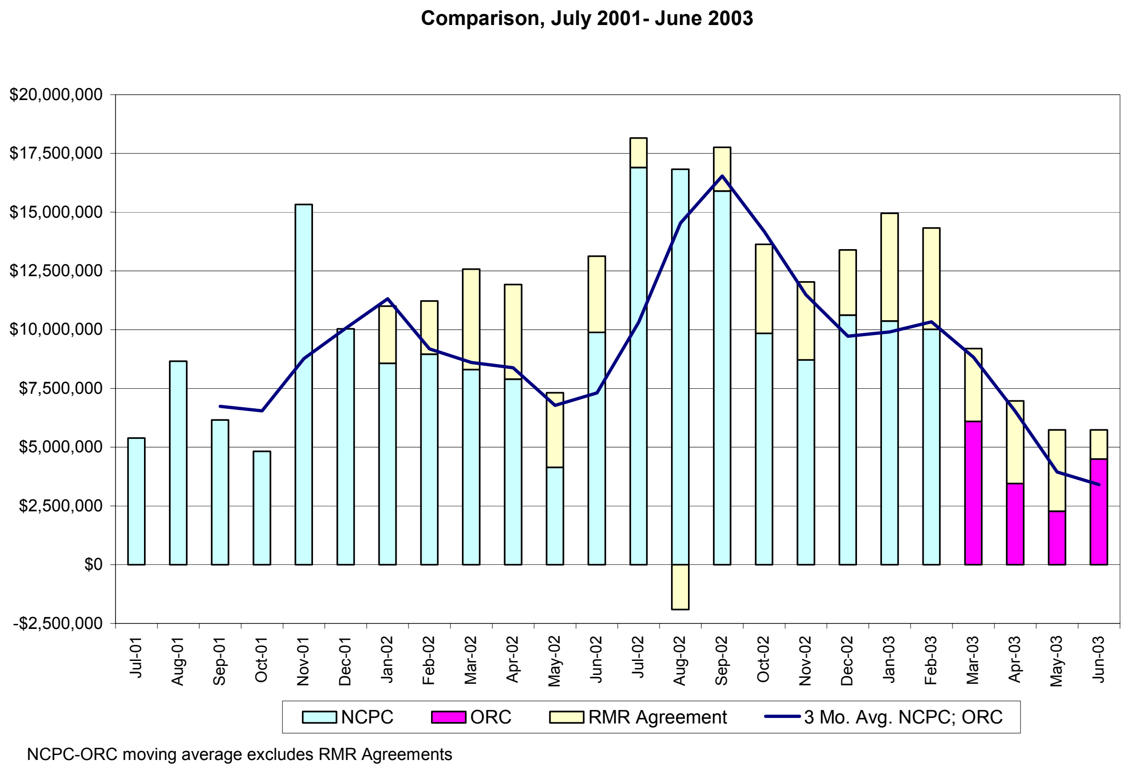
Table 12 shows the total payments, associated MWh, and $/MWh value paid to eligible resources during the quarter. Sixty-five percent of ORC was to RT market resources, primarily for Economic and Daily RMR resources. Payments in April caused the VAR ORC compensation for the quarter to total over $3 million. In the Interim Markets, Net Commitment Period Compensation (NCPC) payments were made to resources. As shown in Figure 6, the level and trend of ORC payments under SMD is significantly lower than NCPC payments that predated them.

Table 12 – Economic, RMR, and VAR ORC Payments

Day Ahead Market									
	Economic			RMR			VAR		
Month	ORC Paid	MWh	$/MWh	ORC Paid	MWh	$/MWh	ORC Paid	MWh	$/MWh
March	$579,505	41,257	$14.05	$54,695	8,965	$6.10	$609,297	14,467	$42.12
April	$76,514	76,083	$1.01	$44,087	1,534	$28.74	$2,037,634	46,316	$43.99
May	$95,952	64,400	$1.49	$16,304	5,040	$3.23	$617,888	37,993	$16.26
June	$806,733	86,875	$9.29	$0	-	$0.00	$82,328	19,384	$4.25
Total	$1,558,704	268,615	$5.80	$115,086	15,539	$7.41	$3,347,147	118,160	$28.33

Real Time Market									
	Economic			RMR			VAR		
Month	ORC Paid	MWh	$/MWh	ORC Paid	MWh	$/MWh	ORC Paid	MWh	$/MWh
March	$1,785,338	145,519	$12.27	$1,330,094	58,867	$22.59	$101,104	2,432	$41.57
April	$520,545	60,789	$8.56	$331,349	21,538	$15.38	$290,769	15,789	$18.42
May	$967,332	109,332	$8.85	$299,139	5,123	$58.39	$91,077	7,545	$12.07
June	$1,606,391	94,178	$17.06	$1,839,557	41,490	$44.34	$88,919	1,058	$84.04
Total	$4,879,606	409,818	$11.91	$3,800,139	127,018	$29.92	$571,869	26,824	$21.32

Figure 6 – NCPC, ORC, and RMR Agreement Monthly Cost



4.2.2. RMR ORC Payments

Table 13 presents the RMR ORC information for each of the load zones. RMR ORC payments in the DA market were split almost equally between the Connecticut and NEMA/Boston Load Zones, although roughly 87% of the MWh were in the NEMA/Boston Load Zone.

RT ORC payments also were almost equally split between the Connecticut and NEMA/Boston load zones, with a small amount in the Western/Central Mass. load zone. Approximately 62% of the MWh for RMR were in the NEMA/Boston Load Zone.

Table 13 – RMR ORC Payments by Zone

Load Zone or External Node	ORC Payments	ORC MWh	$/MWh
Day Ahead Market			
Total	**$115,085.40**	**15,539.0**	**$7.41**
Maine	$0.00	-	$0.00
New Hampshire	$0.00	-	$0.00
Vermont	$0.00	-	$0.00
Connecticut	$54,696.98	2,083.6	$26.25
Rhode Island	$0.00	-	$0.00
SEMASS	$0.00	-	$0.00
WCMASS	$0.00	-	$0.00
NEMA/Boston	$60,388.42	13,455.4	$4.49
Real Time Market			
Total	**$3,800,138.74**	**127,018.8**	**$29.92**
Maine	$0.00	-	$0.00
New Hampshire	$0.00	-	$0.00
Vermont	$0.00	-	$0.00
Connecticut	$1,942,294.48	47873.519	$40.57
Rhode Island	$0.00	-	$0.00
SEMASS	$0.00	-	$0.00
WCMASS	$18,134.54	490.2	$36.99
NEMA/Boston	$1,838,257.79	78561.033	$23.40
Highgate External	$1,451.93	94.9	$15.45

4.2.3. Uplift and ORC

From the beginning of the markets in May 1999 through June 2001, participants were eligible to receive uplift payments for hourly shortfalls between energy costs, represented by their bids, and energy market compensation. Uplift payments were made both to units constrained on for transmission congestion and to units constrained on for non-transmission reasons. During the July 2001 through February 2003 period of the Interim Markets, participants received NCPC payments. NCPC was calculated on a daily basis in a manner similar to the ORC calculation. Although the eligibility criteria and calculation methods for uplift payments, NCPC payments, and the new ORC payments differ, all three represent payments outside of those based on the energy clearing price.

Figure 6, presented earlier, illustrates that, on an overall basis, the advent of ORC has significantly lowered the level of "out of market" compensation.

4.2.4. RMR Agreement Payments

In addition to ORC payments, monthly payments are made to certain generators with Reliability Must Run (RMR) agreements. These agreements reflect a determination by ISO-NE that these resources are needed to maintain transmission system reliability and will be required to run out-of-economic-merit-order during transmission constraints for voltage support, operational reserves, or other reliability reasons. Resources under RMR agreements are required to base energy bids on their short-run variable cost. Payments made to generators under RMR agreements are distinct from RMR ORC payments. RMR payments to resources for January

2002 through June 2003 are included in Figure 6. This figure compares total monthly payments for NCPC, ORC, and RMR agreements for the past two years.

4.3. Installed Capacity (ICAP) Market

4.3.1. Overview

NEPOOL ICAP requirements are calculated each year based on the Northeast Power Coordinating Council (NPCC) resource adequacy standard and, with input from NEPOOL Participants, are converted by ISO-NE into Unforced Capacity (UCAP) requirements for the entire control area. The UCAP requirements are then allocated to participants. Participants can meet their UCAP obligations through bilateral transactions, self-supply, resource-backed external transactions, Hydro Quebec Interconnection Capability Credits, or purchase of UCAP in either of two (supply and deficiency) auctions administered by ISO-NE.

4.3.2. Supply and Deficiency Auctions

ISO-NE conducts a supply auction at the middle of each month to facilitate the transaction of Installed Capacity (ICAP.) Installed capacity must be held or procured by load serving entities to satisfy their capacity obligations. The market commodity is now referred to as Unforced Capacity (UCAP). UCAP differs from ICAP in that UCAP reflects the probability that a resource will be unavailable to serve load due to forced outages.

If, after the supply auction, ISO-NE determines that any load serving participant has failed to procure sufficient UCAP to cover its monthly requirement, ISO-NE will conduct a deficiency auction. Participants are required to offer any UCAP that is in excess of their UCAP requirement in the deficiency auction. If a participant is still deficient after the deficiency auction, the participant must pay a deficiency charge. Table 14 shows the clearing prices for the first three ICAP auctions during the SMD period.

Table 15 following shows the market activity in support of the ICAP market. Most ICAP requirements are met through either self-supply or bilateral contracts, and small amounts are traded through the supply and deficiency auctions. Due to definitional differences, the breakdowns for March 2003 cannot be shown.

Table 14 – ICAP Monthly Auction Results for the Quarter

		Supply Auction				Deficiency Auction[9]			
Oblig. Month	Pool UCAP Req't (MW)	Total Supply Offers (MW)	Total Demand Bids (MW)	Cleared (MW)	Clearing Price ($/MW-Month)	Total Supply Offers (MW)	Total Deficiency (MW)	Cleared (MW)	Clearing Price ($/MW-Month)
Mar-03	28,254.00	N/A	N/A	N/A	N/A	N/A	-44.208	N/A	$4,870.00
April-03	26,372.98	2,357.401	1,063.403	310.310	$400.00	4,379.169	-204.271	204.271	$0.00
May-03	26,372.98	2,323.624	1,700.497	1,125.497	$150.00	5,068.334	-15.448	15.448	$0.00
June-03	27,142.39	4,547.697	1,186.825	780.545	$200.00	4,059.890	-1,206.563	1,206.563	$0.00

Table 15 – ICAP Requirement Sources by Month

All Values in MW	March	April	May	June
Self Supplied		11,936.595	12,298.959	12,633.646
Bilateral Market		14,013.985	13,427.960	13,916.013
Supply Auction		310.310	715.933[10]	780.545
Deficiency Auction	44.208	204.271	15.448	1,206.563
Total Obligation (Includes Excess Sales by Participants)		26,465.160	26,458.299	28,536.767
Monthly UCAP Requirement	28,254.000	26,372.978	26,372.978	27,142.393
Difference = excess sales by Participants		92.182	85.321	1,394.373

4.3.3. De-Listed Units

NEPOOL Participants owning intermittent resources or desiring to sell the capacity of their generator out of the control area may de-list their unit, subject to approval by ISO-NE. Market Rule 1 specifies that the entire capacity of the unit must be de-listed. While this generally absolves Participants of the requirement to bid into the DA market, they may offer energy into the RT market.

Table 16 below shows the number of units and their summer claimed capability that were de-listed from the ICAP auction by month.

[9] Prior to the April 2003 Obligation Month, the Capacity Market was operated on a different basis, with a uniform deficiency charge assessed for ICAP deficiencies.

[10] This value represents the amount of MW cleared in the supply auction that was actually necessary to satisfy participant obligations. In May, participants in the supply auction procured approximately 1,125 MW (Table 14) when only 716 MW were required to satisfy their actual obligation.

Table 16 – ICAP De-Listed Units

Month	Number of Units	Summer Claimed Capability (MW)
Mar-03	n/a	n/a
Apr-03	3	54.562
May-03	10	253.662
Jun-03	10	253.662

4.4. Financial Transmission Rights (FTR) Auctions

4.4.1. Overview

A Financial Transmission Right (FTR) is a financial tool that may be used in the DA market to manage congestion risks. An FTR is defined by a specific MW value in one direction between a source point (point of receipt) and a sink point (point of withdrawal) on the transmission grid. FTR holders are entitled to receive congestion revenues (or to pay congestion charges), in each hour, up to an amount equal to the MW value of the FTR times the difference in the congestion components of the DA LMPs for the points defined in their FTR. Therefore, the FTR provides a successful hedge in the DA market so long as day-ahead congestion component differences in LMP are consistent with the differentials expected in the FTR.

In clearing the monthly FTR Auction, ISO-NE employs a Simultaneous Feasibility Test (SFT). SFT is a market feasibility test that ensures revenue adequacy by ascertaining that the transmission system can support the awarded set of FTRs during normal system conditions. The SFT helps to preserve the economic value of FTRs to FTR Holders by ensuring that all FTRs awarded can be accommodated in the system.

The SFT uses a DC power flow model that models the auction bids and offers and expected network characteristics during the period being analyzed. SFTs are run during the determination of the winning quotes for the FTR Auction.

The SFT evaluates the ability of all system facilities to remain within normal limits during normal, extended-period operation. The system must also be able to sustain any single transmission contingency event with all system facilities remaining within applicable emergency limits.

The winning quotes are determined by the set of simultaneously feasible FTRs with the highest total auction value, as determined by the bids of the buyers and taking into account the reservation prices of the sellers. This ensures that the ISO awards the set of FTRs and allocates them among auction participants in such a way that the value-based transmission utilization is maximized.

After determining the winning quotes, the results are published and settlements occur. Winning bidders pay or receive payments for FTRs acquired in the auction based on the market prices determined in the FTR Auction; FTR sellers pay or receive payments for the FTRs they surrender to the ISO based on the market prices cleared in the FTR Auction. In NEPOOL, FTRs may be obtained in two ways: through an FTR Auction (primary method) or through the Secondary Market (secondary method).

As discussed previously, the auction awards the set of FTRs that are both simultaneously feasible and which maximize the value of the auction while respecting the limits of the transmission system. This set of FTRs results in a clearing price at each node, or location, on the system. Utilizing these clearing prices, one can subtract any sink location from any source location to derive the value that the auction placed upon an FTR in that direction on that path. By applying load weighting, the clearing prices for each load zone can be derived.

4.4.2. Auction Results for the Quarter, On-Peak and Off-Peak

The entire capacity of the NEPOOL transmission system was made available for each of the March - June auctions. Since these were monthly auctions, and longer-term auctions are not contemplated until later in the year, there was only “buy” activity.

The first Long-Term FTR Auction will be conducted for the period October through December 2003. Fifty percent of the capacity of the NEPOOL transmission system will be available to Eligible FTR Bidders for the long-term auction with the remaining transmission system capacity made available in the October, November and December monthly FTR Auctions.

The following figures summarize the results of the auctions held for each month in the quarter.

Figure 7 – Monthly On-Peak FTR Auction Results

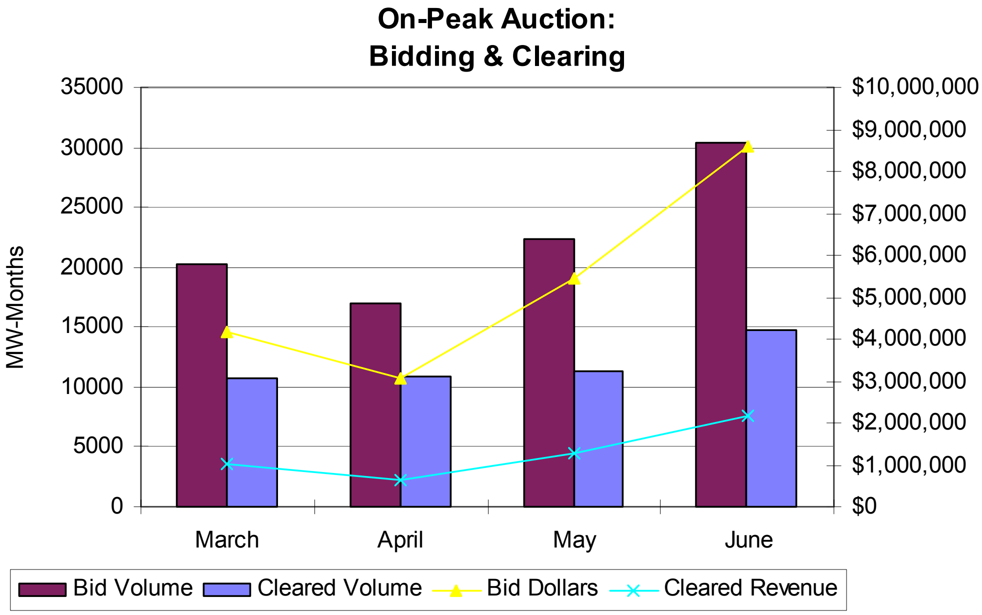


Figure 8 – Monthly Off-Peak FTR Auction Results

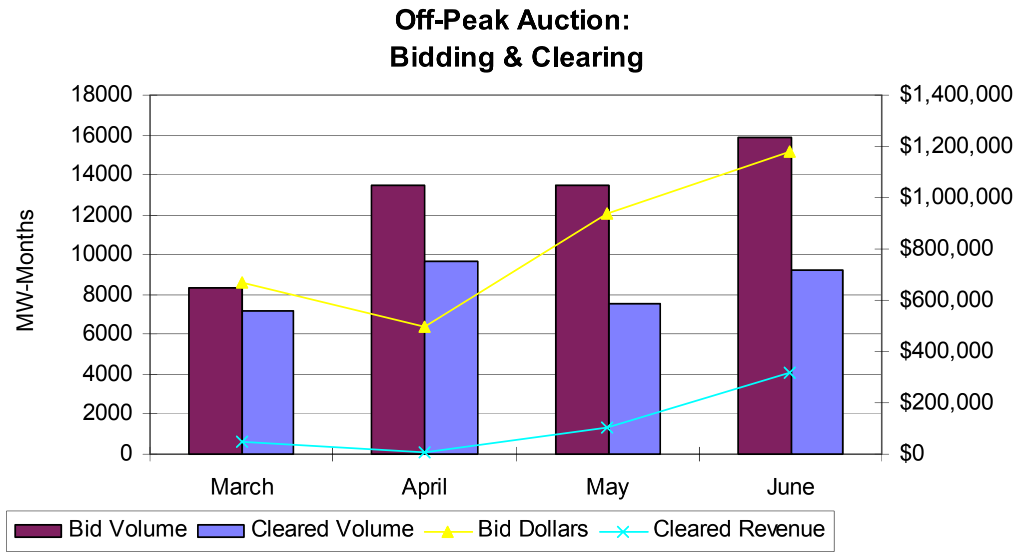


Figure 9 – Price/Volume Composition of Cleared FTR Bids (On-Peak)

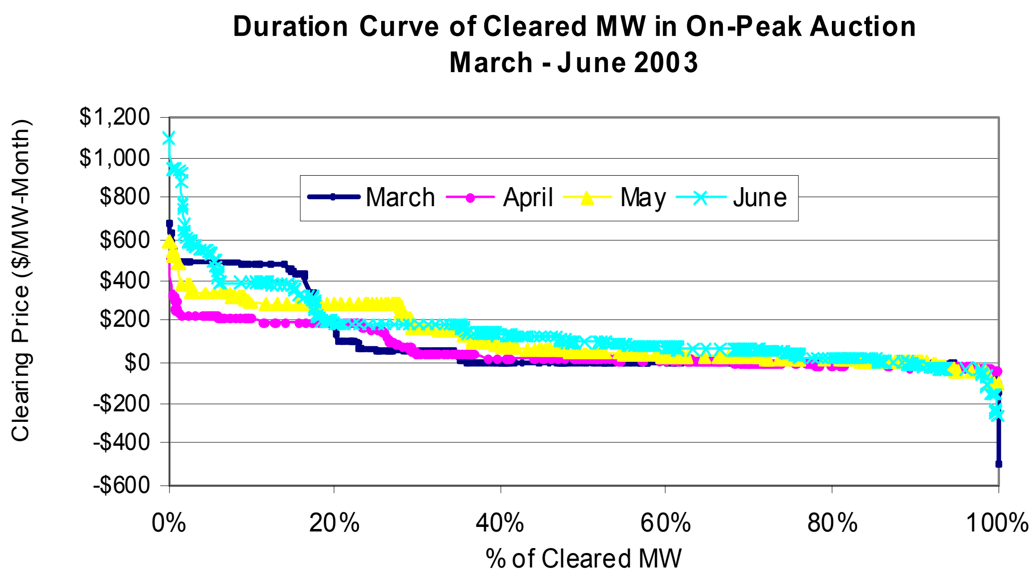
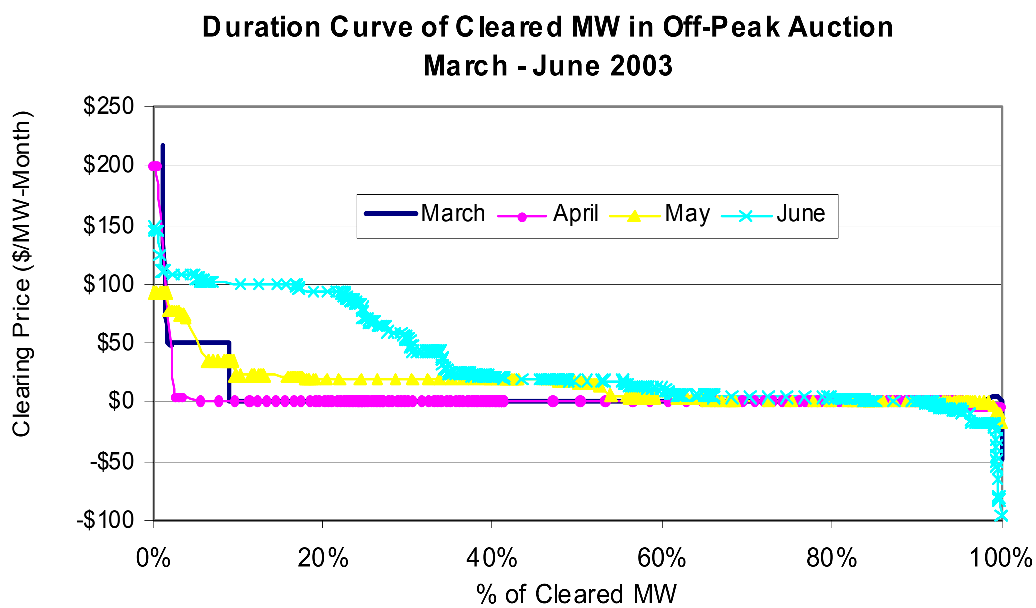


Figure 10 – Price/Volume Composition of Cleared FTR Bids (Off-Peak)



4.4.3. FTR Secondary Market

The Secondary Market is the only source for entities desiring to secure a registered FTR after completion of the auctions. Because each of the first monthly auctions made the entire capacity of the NEPOOL system available, there was no trading activity in the FTR Secondary Market during the quarter in the ISO-NE system. Allocations from the Congestion Revenue Fund are only made to FTR holders of record, so arrangements made by Participants outside of this system are unknown to ISO-NE.

The Long Term Auction schedule will be adjusted to provide two six-month Auctions followed by annual Auctions synchronized on a calendar year basis. Thus, the second Long Term auction will be for the period January 1 – June 30, 2004 and the third will be for July 1 – December 31, 2004. The following factors were considered in this choice of time frame:

- There is no alignment between NYISO and PJM auction periods. Each synchronizes to the beginning of their summer rating period for transmission facilities, and are different from that of ISO-NE. Business interests, including retail market considerations, within New England outweighed potential synergies of synchronizing with our neighbors.

- Some Participants expressed a desire to accommodate the timing of RFPs for serving load, some of which encompass January to December, while others cover the period January to June.

- A shorter than one-year term would more readily accommodate possible modifications to the SMD financial model such as changes to the currently defined load zones and additional hub definitions.

- Additional experience with multi-month FTR Auctions is desirable before bidders become bound to a full-year commitment.

4.4.4. Transmission Congestion Revenue Fund & FTR Positive Target Allocations

Once an FTR is obtained, the holder has the right to collect credits or an obligation to pay charges for each congested hour of the month. The amount is based upon the DA congestion component differential between the sink and source point defined in the FTR. Those experiencing DA congestion in the opposite direction of their FTR for a given hour are charged a Negative Target Allocation. Those who held an FTR in the same direction of DA congestion are assigned a Positive Target Allocation. For those with positive allocations, a cursory method of assessing the successfulness of an FTRs hedge is accomplished by determining the extent to which they received their full Positive Target Allocation payout from the Transmission Congestion Revenue fund during positive congestion along their FTR path. If the fund is large enough, then those with positive target allocations will be paid in full, otherwise only a pro-rata amount will be paid.

The Transmission Congestion Revenue fund is the fund from which FTR holders may be paid. It consists of four components, as displayed by the following formula:

Monthly Transmission Congestion Revenue = (DA & RT Congestion Revenue) + (absolute value of the sum of Negative FTR Target Allocations over all hours in the month) + (excess Monthly Congestion Revenue from previous months) + fund adjustment

Table 17 shows the contribution of each component (including negative FTR target allocations) to the Monthly Congestion Revenue fund for March, April, May, and June. It also shows the positive target allocations that were paid out and lastly, the ending balance of the fund (or surplus) for the month.

Table 17 – Congestion Revenue Fund Summary

Contributing Component	March	April	May	June
Fund Beginning Balance	$0.00	$15,097,556.29	$18,489,756.77	$20,221,054.36
Fund Adjustment	$0.00	$1,471.22	$6,545.53	$6,098.51
Pool DA Congestion Revenue	$15,451,501.90	$6,666,907.24	$4,388,518.50	$17,722,246.76
Pool RT Congestion Revenue	$296,109.63	$760,130.49	$252,525.72	$383,626.85
Pool FTR Negative Target Alloc's.	$1,751,025.36	$1,282,003.47	$987,674.66	$4,607,344.42
Available Congestion Revenue	**$17,498,636.89**	**$ 23,808,068.71**	**$ 22,149,671.86**	**$ 42,940,370.90**
Pool Positive Target Allocations	$2,401,080.60	$ 5,318,311.94	$ 3,903,966.82	$24,094,792.81
Monthly Fund Surplus or Shortfall	$15,097,556.29	$18,489,756.77	$20,221,054.36	$18,845,578.09

For each of the four months, FTR holders received 100% of their Positive Target Allocations. However, in June some of the monthly fund surplus was needed to accomplish this. Since more was paid out of the FTR market (in Positive Target Allocations) than was collected (through congestion revenue and Negative Target Allocations) for the month of June, the rolling monthly surplus was reduced and the fund's ending balance was lower than its beginning balance for the first time since the beginning of the auction.

While the congestion fund/FTR methodology is designed to ensure revenue adequacy, day-to-day variations in system topology (such as transmission outages) and the amount of RT congestion versus DA congestion (upon which FTR holders are compensated) can result in under-collection.

Any excess Monthly Transmission Congestion Revenue that remains unallocated is carried forward for use in subsequent months and, at the end of the calendar year, any excess Monthly Transmission Congestion Revenue is distributed first to FTR Holders that were paid less than their positive Target FTR Allocations and then pro-rata to Participants who paid Congestion Costs during the year.

4.4.5. Auction Revenue Rights Allocations

Auction Revenue is allocated to two main areas. Firstly, it is allocated in the form of Qualified Upgrade Awards (QUAs) to entities that, by paying for transmission upgrades, have increased the transfer capability of the NEPOOL transmission system and enabled more FTRs to be available in the FTR auction. Secondly, it is allocated through the Auction Revenue Rights (ARR) process, where it is primarily received by congestion paying load-serving entities (LSEs).

Table 18 displays the share of auction revenue that was allocated to QUAs and through the ARR process for the months of March - June. Figures include amounts from both the On and Off-Peak auctions.

Table 18 – Total Auction Revenue Distribution

March - June 2003			
Month	**QUA Dollars**	**ARR Dollars**	**Total Auction Allocation**
MARCH	$5,180.05	$1,050,091.66	$1,055,271.71
APRIL	$342.49	$628,737.80	$629,080.29
MAY	$6,722.45	$1,385,019.55	$1,391,742.00
JUNE	$12,279.42	$2,491,667.62	$2,503,947.04

The ARR process allocates revenue to:

- Excepted Transactions - special grand fathered transactions (listed in Attachment G of NEPOOL Tariff)
- NEMA Contracts - other long-term contracts having delivery in Northeastern Massachusetts.
- Long-Term Firm Through or Out Service.
- Load Share - the proportional Real-Time Load Obligation share of Congestion paying entities at the time of the pool's coincident peak for the month.

Table 19 shows the ARR Dollar allocations amongst these categories for the months of March – June for the Off-Peak and On-Peak auctions and in total.

Table 19 – ARR Dollar Allocations, March – June 2003

Market Name	Peak Hour Load (MW)	Excepted Transaction Dollars	NEMA Contract Dollars	Load Share Dollars	Long-Term Firm Trans. Service Dollars	Total ARR Dollar Allocations
OFF-PEAK AUCTION						
MARCH	20,031	$51.76	$193.28	$42,658.74	$181.55	$43,085.33
APRIL	17,787	$50.36	$33.39	$8,040.56	$2.39	$8,126.70
MAY	16,499	$2,335.83	$6,754.98	$94,441.36	$268.18	$103,800.35
JUNE	24,967	$2,963.39	$17,892.47	$285,032.26	$525.86	$306,413.98
Cumulative Totals		*$5,401.34*	*$24,874.12*	*$430,172.92*	*$977.98*	*$461,426.36*
ON-PEAK AUCTION						
MARCH	20,031	$6,271.69	$58,326.78	$938,400.61	$4,007.25	$1,007,006.33
APRIL	17,787	$9,986.33	$80,650.89	$529,910.27	$63.61	$620,611.10
MAY	16,499	$38,822.23	$130,176.04	$1,110,749.52	$1,471.41	$1,281,219.20
JUNE	24,967	$30,926.40	$116,336.59	$2,035,552.01	$2,438.64	$2,185,253.64
Cumulative Totals		*$86,006.65*	*$385,490.30*	*$4,614,612.41*	*$7,980.91*	*$5,094,090.27*
TOTAL AUCTION						
MARCH	20,031	$6,323.45	$58,520.06	$981,059.35	$4,188.80	$1,050,091.66
APRIL	17,787	$10,036.69	$80,684.28	$537,950.83	$66.00	$628,737.80
MAY	16,499	$41,158.06	$136,931.02	$1,205,190.88	$1,739.59	$1,385,019.55
JUNE	24,967	$33,889.79	$134,229.06	$2,320,584.27	$2,964.50	$2,491,667.62
Cumulative Totals		*$91,407.99*	*$410,364.42*	*$5,044,785.33*	*$8,958.89*	***$5,555,516.63***

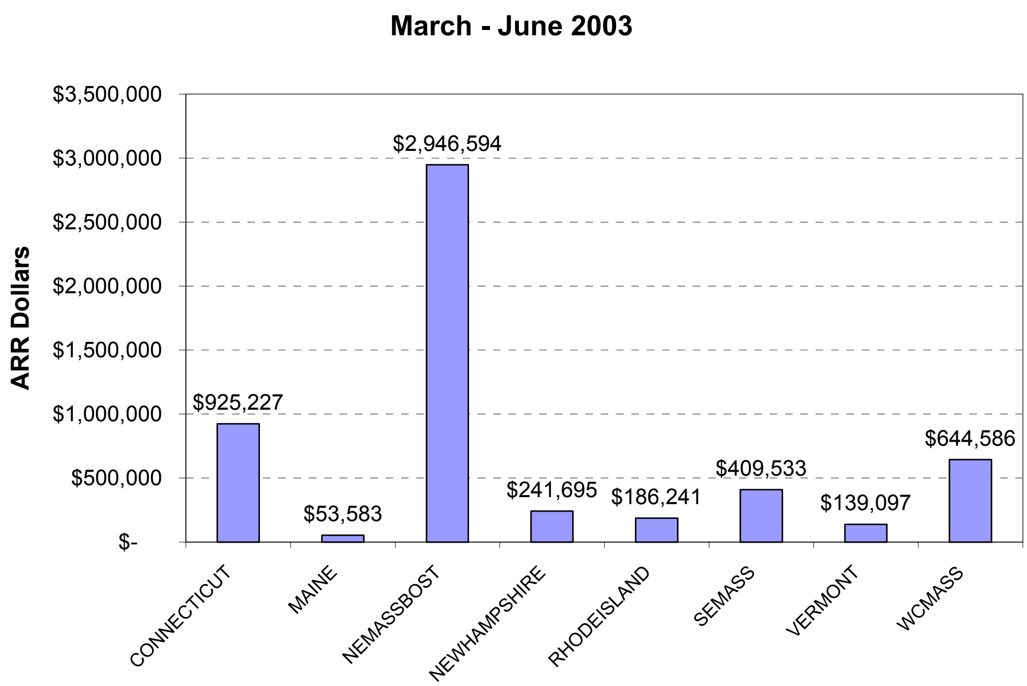
Table 20 displays the distribution of ARR dollars by zone for the months of March - June for the On and Off-peak auctions.

Table 20 – ARR Award Distribution by Zone, March – June 2003

Zone	March	April	May	June
OFF-PEAK				
.Z.MAINE	$6,127.25	$1,049.27	$1,941.48	$2,724.57
.Z.NEWHAMPSHIRE	$11,088.30	$844.92	$1,953.92	$14,744.69
.Z.VERMONT	$1,650.34	$46.15	$2,456.77	$12,460.01
.Z.CONNECTICUT	$8,141.85	$2,502.29	$10,595.78	$51,297.48
.Z.RHODEISLAND	$2,030.00	$505.24	$1,022.41	$19,886.20
.Z.SEMASS	$3,555.90	$678.34	$4,929.53	$35,433.00
.Z.WCMASS	$4,601.01	$789.62	$18,632.71	$59,379.42
.Z.NEMASSBOST	$5,709.13	$1,708.48	$61,999.57	$109,962.75
ON-PEAK				
.Z.MAINE	$12,389.19	$8,301.49	$11,747.19	$9,303.64
.Z.NEWHAMPSHIRE	$117,292.99	$10,709.67	$13,205.11	$71,855.24
.Z.VERMONT	$32,641.71	$2,876.75	$26,564.59	$60,400.34
.Z.CONNECTICUT	$228,812.30	$17,527.55	$166,871.33	$439,479.33
.Z.RHODEISLAND	$56,860.96	$4,709.23	$3,566.91	$97,661.04
.Z.SEMASS	$100,358.54	$13,976.11	$15,229.30	$235,371.52
.Z.WCMASS	$126,067.56	$47,557.59	$144,145.02	$243,412.44
.Z.NEMASSBOST	$328,575.83	$514,889.10	$898,418.34	$1,025,331.45

Figure 11 displays the cumulative distribution of ARR Dollars by zone for the period March – June 2003.

Figure 11 – ARR Distribution by Zone



4.5. Load Response Programs

The ISO administers the NEPOOL Load Response Program (the "Program") for the New England wholesale electricity market. During 2002, the ISO and NEPOOL filed new Load Response Programs that, with the exception of the proposed Day-Ahead Demand Response Program, were activated concurrently with SMD. They are:

- Real-Time Demand Response Program (30 minute or 2 hour response)
- Real-Time Price Response Program
- Real-Time Profiled Response Program
- Day-Ahead Demand Response Program

The Real-Time Demand Response Program offers two options – response within 30 minutes or within 2 hours. Customers enrolled in this program receive the real-time zonal price or a guaranteed minimum payment for a minimum of two hours, and are eligible to qualify as an ICAP resource. Because interruption is mandatory under this program, it is sometimes referred to as a "reliability" program.

In the Real-Time Price Response Program, voluntary reductions in load are eligible for compensation when the forecast hourly Zonal Price (based on the results of the Day-Ahead Energy Market or on subsequent Resource Adequacy Analysis) is greater than or equal to $100/MWh. Meter readings are submitted either daily to the ISO on the same schedule as other meter data, or before the end of the 90-day resettlement period, depending on the program option chosen.

The Real-Time Profiled Response Program includes loads that are capable of being interrupted within a specified period of time after an ISO instruction to do so. Loads participating in this program, which must be under the direct control of an Enrolling Participant, may include aggregated residential super-thermostat programs, water heaters, pool pumps, and distributed generation and do not require interval metering. Where they do not, a statistical response factor for the group is reported to the ISO.

ISO-NE also intends to implement a Day-Ahead Demand Response Program. Under this program, ISO-NE would accept offers in the DA market from participating demand side resources. If a load curtailment offer clears in the DA market, the Resource submitting the offer would be paid the day-ahead Locational Marginal Price ("LMP") for the amount of load interruption submitted. According to the approved market rules for this program, offers may range between $50 to $1,000 per MW-hour of load curtailed. Resources participating in this program would also be eligible for ICAP credit. In real time, the Resource would be expected to curtail the amount of load that was accepted in the DA market. If the Resource does not interrupt or does not interrupt up to the bid amount, the Resource will be charged the real-time LMP for the difference. ISO-NE expects that Resources requiring more than 2 hours advance notice in order to curtail consumption would participate in this program. The Commission has directed ISO-NE to implement the program by March 31, 2005.

Table 21 below provides the current enrollments in the Program showing all enrolled participants as of the end of June 2003. Table 22 shows the pending enrollments as of the end of June. It is anticipated that due to the increased marketing efforts enrollments are likely to increase.

Table 21 – Load Response Program Enrollment by Zone, June 30, 2003

Zone	Number of Program Assets	Enrolled MW				
		RT Price	RT 30-Min	RT 2-Hour	Profiled[11]	Total
CT	121	42.8	89.5	1.0	58.6	191.9
ME	3	0.4			65.0	65.4
NEMA	23	42.6	6.8		1.4	50.8
NH	1		0.4			0.4
RI	7	0.8				0.8
SEMA	16	1.6	2.0			3.6
VT	9	1.9	1.2			3.1
WCMA	44	6.4	6.0		6.9	19.3
Total	224	96.5	105.9	1.0	131.9	335.3

Table 22 – Pending Enrollment by Zone, June 30, 2003

Zone	Number of Program Assets	Enrolled MW				
		RT Price	RT 30-Min	RT 2-Hour	Profiled	Total
CT	10		5.1	22.8		27.9
ME	1		14.7			14.7
NEMA	4	5.0	0.9			5.9
NH						0
RI						0
SEMA	2	0.5	0.4			0.9
VT	1				5.9	5.9
WCMA	1		0.3			0.3
Total	19	5.5	21.4	22.8	5.9	55.6

The transition from the pre-SMD program to the SMD Demand Response Program was accomplished by transferring assets that were active on February 28, 2003 to the corresponding SMD Demand Response Program. For instance, if an asset was active in the Type 6 Class 1 program, it was transferred to the 30-minute Real-Time Demand Response Program. An asset in the Type 6 Class 2 program was transferred to the Price Response Program.

During this quarter, there were no events that involved the participation of customers in either the Class 1 (Demand Program) or the 30-minute or 2-hour Real-Time Demand Response Program. In other words, during the reporting period none of the reliability programs (pre-SMD and SMD) were activated because the system did not require them. However, there were payments to customers in the

[11] Includes 130.9 MW of formerly Type 2 interruptible loads.

Type 6 Class 1 program. Table 23 below details instances of implementation of the Load Response Programs during the quarter.

Table 23 – Load Response Events, Q2 2003

Program	Zone(s)	Date	Event start	Event end	Duration (hours)
Price Response	ALL	03/03/03	7:00	18:00	11
Price Response	ALL	03/04/03	7:00	18:00	11
Price Response	ALL	03/05/03	7:00	18:00	11
Price Response	ALL	03/06/03	7:00	18:00	11
Price Response	ALL	03/07/03	7:00	18:00	11
Price Response	ALL	03/10/03	7:00	18:00	11
Price Response	ALL	03/11/03	7:00	18:00	11
Price Response	ALL	03/12/03	7:00	18:00	11
Price Response	ALL	03/13/03	7:00	18:00	11
Price Response	CT, NEMA, VT, WCMASS	03/14/03	7:00	18:00	11
Price Response	ALL	03/14/03	8:19	18:00	10
Price Response	VT	04/04/03	7:00	18:00	11
Price Response	NH, CT, NEMA, VT, WCMASS, SEMA, RI	04/04/03	7:00	18:00	11
Price Response	NH, VT	04/08/03	7:00	18:00	11
Price Response	NH, CT, NEMA, VT, WCMASS, SEMA, RI	04/11/03	7:00	18:00	11
Price Response	ALL	04/14/03	10:00	18:00	8
Price Response	ALL	06/05/03	7:00	18:00	11
Price Response	VT	06/25/03	12:00	18:00	6
Price Response	CT, NEMA	06/26/03	7:00	18:00	11
Price Response	ALL	06/27/03	7:00	18:00	11

5. Market Analysis

5.1. All-In Price of Wholesale Electricity

5.1.1. Calculation

LMPs cannot be directly compared with the Interim Market ECPs because of fundamental differences between the methods for calculating locational and uniform system prices. However, the average monthly All-In Price provides a useful measure of the trends in wholesale electricity prices over time. The All-In Price incorporates energy, reserve, regulation, Uplift or ORC costs, and the cost of Reliability Must Run (RMR) contracts. The All-In Price also accounts for revenues and charges related to the Marginal Loss Revenue Fund, Congestion Revenue Fund, and FTR and ARR allocations. The inclusion of these revenues and charges makes the All-In Price for the SMD and Interim Market periods more comparable by accounting for revenues returned to load as well as all costs. The All-In Price is computed at the hourly level and is reported here in $/MWh.

For the Interim Markets period ending February 2003, the All-In Price was calculated as follows:

> *All-In Price =[(ECP * system load) + total reserve market payments + total AGC market payments + total Uplift or NCPC payments + RMR contract payments]/system load.*

For the SMD market period beginning March 1, 2003, the hourly All-In Price is calculated as follows:

> *All-In Price =[sum(DA LMP * DA cleared locational demand) + DA ORC + sum(RT LMP * RT locational load deviation) + pro-rated RT ORC + total regulation payments+ RMR contract payments + Net FTR auction dollars + FTR negative allocations – FTR positive allocations – marginal loss revenue fund – congestion revenue fund – ARR dollars allocation] / [sum(DA cleared demand) + sum(RT load deviation)].*

5.1.2. Historical Series

Figure 12 below shows the daily average All-In Price of Wholesale Electricity for the second quarter of the years encompassing wholesale electricity markets in New England, 1999-2003. Table 24 shows the averages (means and medians) and standard deviations of Q2 All-In Prices for the current and past years.

The quarterly average All-In price began at $39.40/MWh in 1999[12], rose to $44.31/MWh in 2000 then fell each year subsequently, and averaged $52.65/MWh during the second quarter of 2003. The increase in 2003 is mainly attributable to elevated prices for input fuels. (See Section 5.4). The median price, which had fallen in 2002, rose to $46.47 in 2003. The minimum price rose decidedly this year, and this year featured a level of price volatility (as expressed by standard deviation) that has not been seen since 1999 and 2000.

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[12] May and June only.

Figure 12 – Daily Average All-In Price

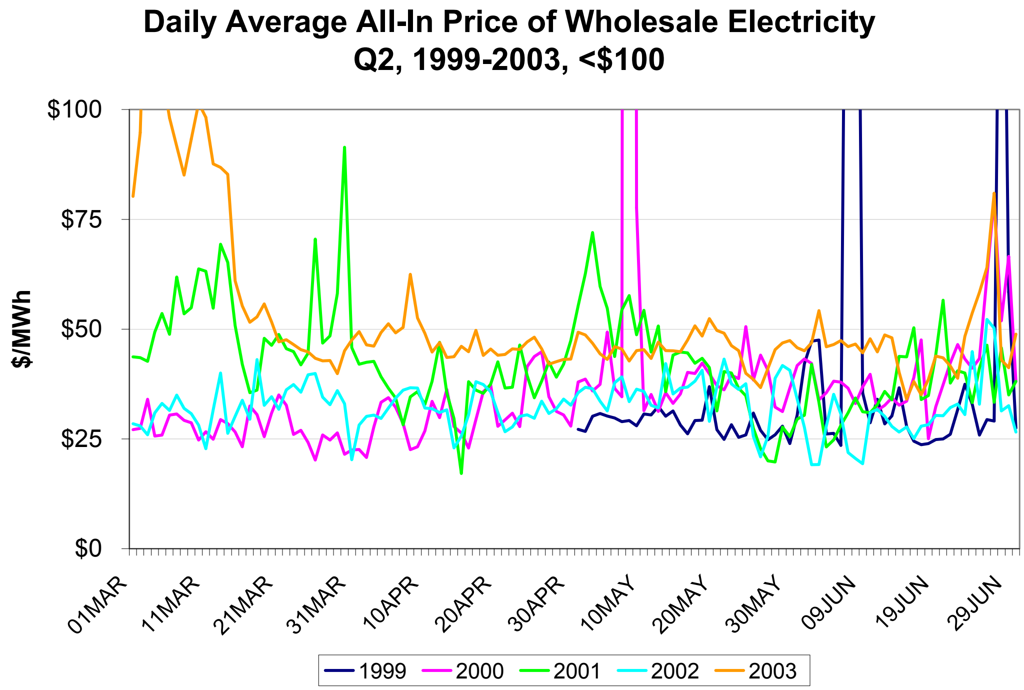


Table 24 – Quarterly Statistics for Daily All-In Price of Wholesale Electricity ($/MWh)

Year	Mean Daily Price	Median Daily Price	Max. Daily Price	Min. Daily Price	Std. Dev. Daily Price
1999 Q2	$39.40	$29.07	$232.37	$23.54	$42.09
2000 Q2	$44.31	$33.45	$1,219.56	$20.18	$107.72
2001 Q2	$42.31	$41.96	$91.41	$17.11	$11.59
2002 Q2	$32.43	$32.02	$52.22	$19.12	$5.80
2003 Q2	$52.65	$46.47	$150.24	$34.04	$18.45

5.2. Average Virtual Offer/Bid Volumes and Cleared Quantities

Participants can bid fixed and price-sensitive demand into the DA market. These demand bids must be associated with a physical load that has been registered as a load asset, and except for those associated with external contracts, they must be submitted at a load zone. Fixed (or self-scheduled) demand bids must specify the MW quantity that the participant is committing to purchase DA, while price-sensitive demand must specify the MW quantity that the participant wishes to purchase in the DA market along with the price above which the demand should not be scheduled.

Participants may also submit virtual demand (decrement) bids at the Hub, at any load zone, or at any node where an LMP is calculated. Virtual demand bids are not required to be associated with a physical load at the specified location.

Figure 13 shows average hourly bid-in and cleared demand and virtual supply for the quarter. Table 25 shows the total MW submitted and cleared for virtual supply offers and virtual demand bids by location. Since Figure 13 shows data for all nodes while Table 25 shows data for the load zones and internal hub only, the numbers in the two exhibits are not the same.

Figure 13 – Average Hourly Bid and Cleared Quantities for the Quarter

All Locations, Day Ahead Market, Q2 2003

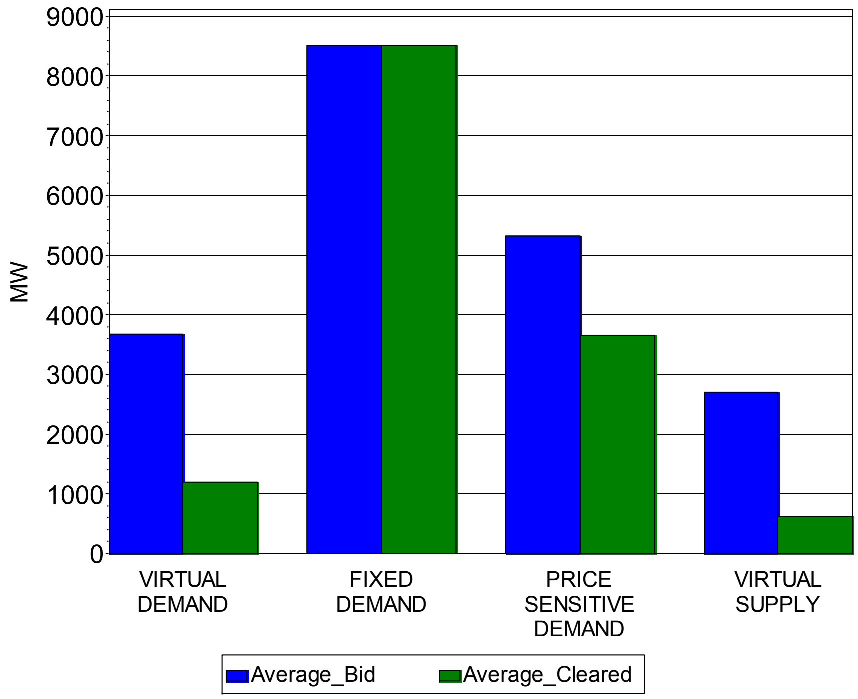
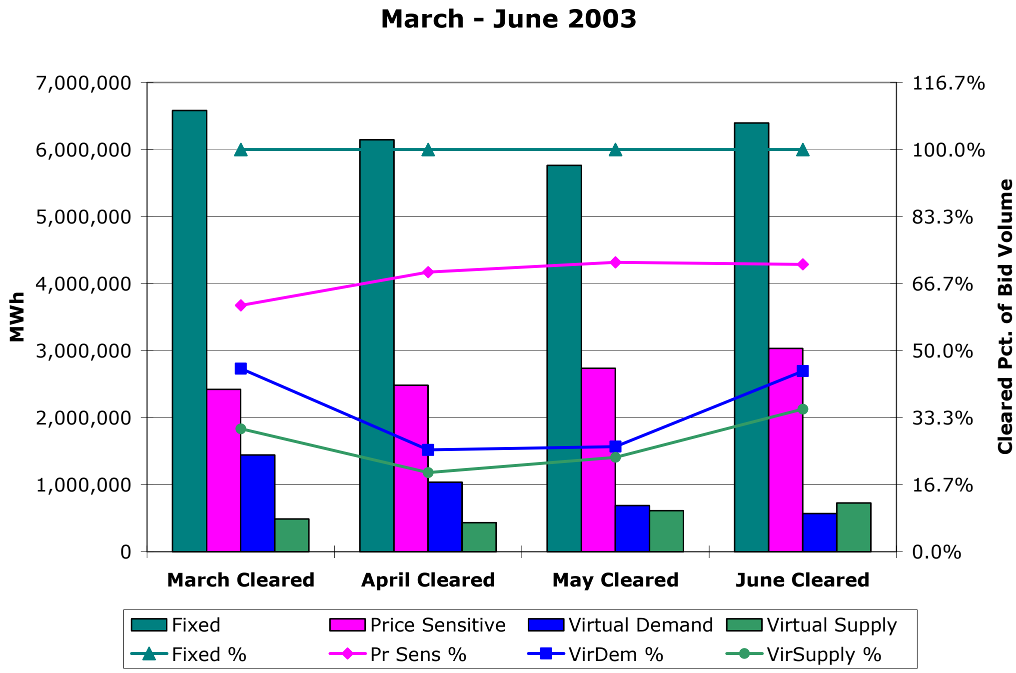


Table 25 – Virtual Supply and Demand by Load Zone for the Quarter

Location	Submitted Virtual Supply (MWh)	Cleared Virtual Supply(MWh)	Submitted Virtual Demand(MWh)	Cleared Virtual Demand(MWh)
Internal Hub	798,146.20	592,257.70	975,556.00	693,636.80
Maine Load Zone	473,649.30	219,499.20	393,991.70	206,992.40
New Hampshire Load Zone	297,874.10	62,386.20	88,621.00	51,265.60
Vermont Load Zone	26,991.80	15,238.90	250,261.50	193,160.60
Connecticut Load Zone	124,695.60	76,704.80	412,974.00	74,499.90
Rhode Island Load Zone	823.80	510.30	72,248.60	22,006.00
SEMASS Load Zone	53,127.50	20,391.50	85,086.60	26,630.10
WCMASS Load Zone	438.80	118.10	106,836.70	44,787.30
NEMA/Boston Load Zone	37,996.60	31,828.30	796,822.80	132,880.10

Figure 14 below shows the total cleared volume (in MWh and as a percent of bid volume) for each of fixed demand, price sensitive demand, virtual supply (increment bids), and virtual demand (decrement bids) by month during the quarter. The MWh volume of price sensitive bids that cleared increased during the quarter, while the virtual supply and demand bids that cleared as percent of total bid fell and then rose again in June.

Figure 14 – Cleared Bid Volumes and Percentage of Total Bid



5.3. Day-Ahead and Real-Time Price Convergence

A significant concern under a Multi-Settlement Market system is the degree to which pricing in the DA market is a predictor of the RT market price. Divergence between these two price series could be an indicator of a flaw in the market or attempts at manipulation. The quarterly average hourly DA LMP at the Hub was $53.30, while the average hourly RT LMP was $52.53 – a high degree of convergence. Analysis of daily averages yields still further insight.

Figure 15 plots +/- 1 standard deviation around the daily average hourly DA LMP at the Hub compared to the daily average hourly RT LMP. The average standard deviation of the average daily DA Hub LMP was $8.78, while the RT average standard deviation was $14.88. Analysis indicates that over 75% (92/122 days) of the time, the daily RT average hourly prices lie within the bandwidth described by +/- 1 standard deviation of the daily average hourly DA LMP at the Hub. This suggests a strong convergence between the DA and RT market prices and supports the conclusion that the DA market price is a solid predictor of RT prices.

Figure 16 plots a comparison of the DA hourly average price versus the corresponding RT hourly average price at the Hub for the on and off-peak periods. A little more than 50% of the time, the RT price in the off-peak period was within +/- 10% of the DA price, while the percentage rose to more than 60% for the on-peak hours. For the quarter, the overall average relationship between the DA and RT prices for both the on-peak and off-peak was close to unitary, further demonstrating the DA price as a significant predictor of RT pricing.

Figure 15 – DA vs. RT LMP Price Convergence at the Hub

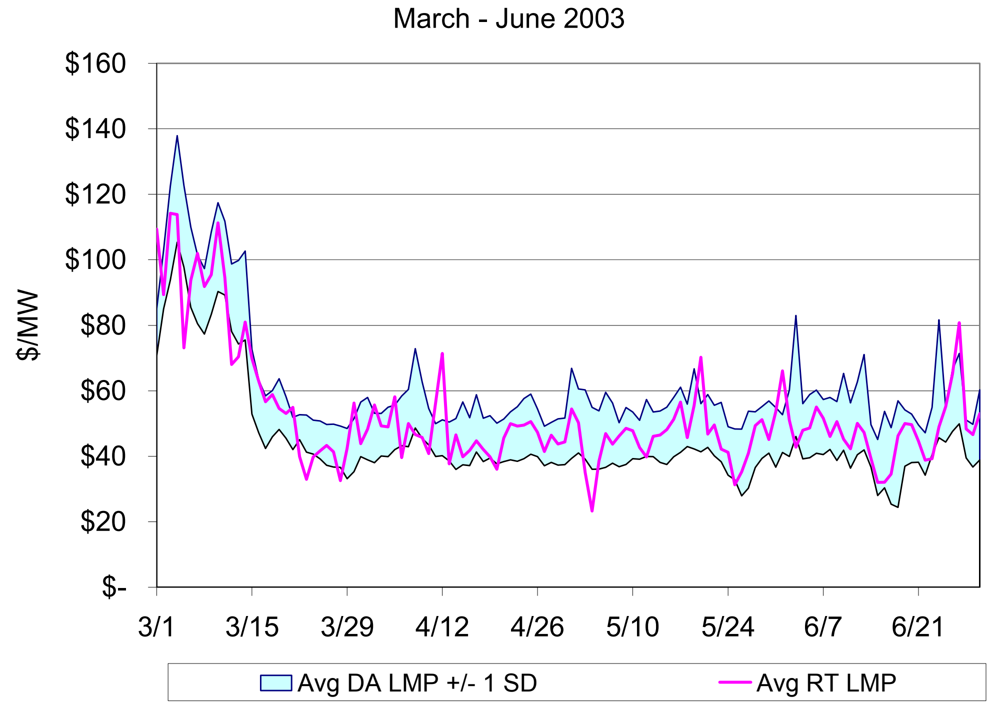
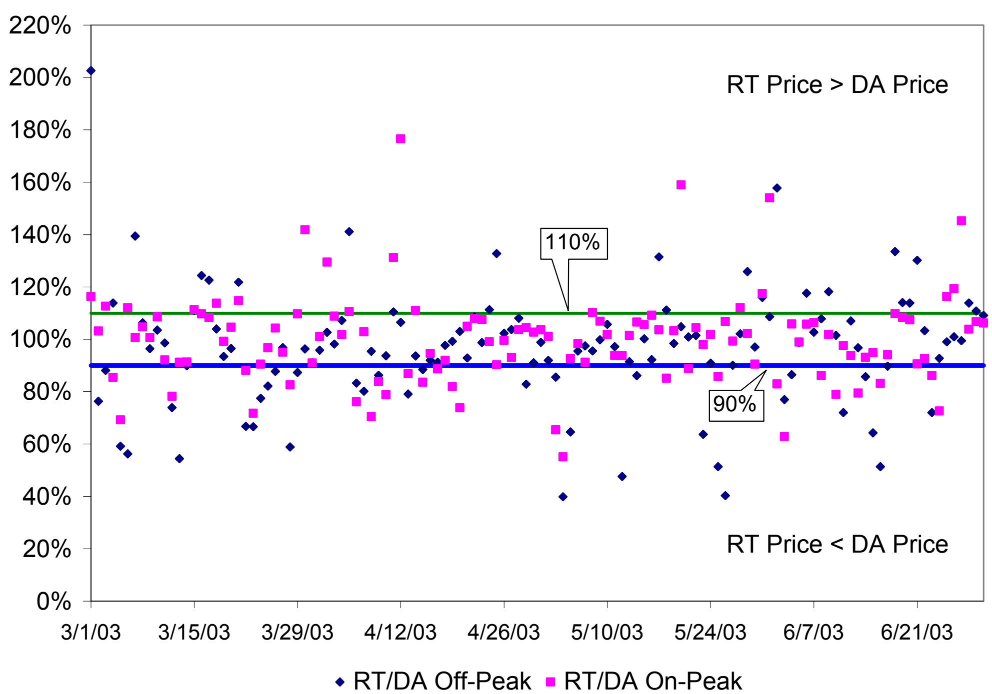


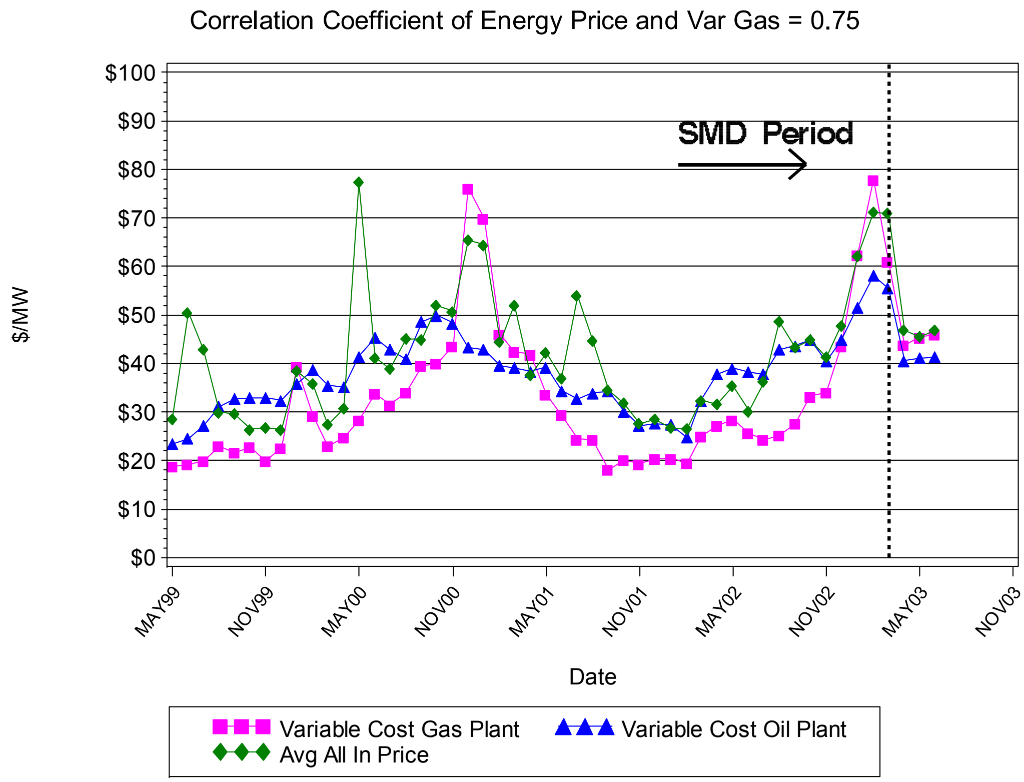
Figure 16 – DA vs. RT Hub Price, On and Off-Peak



5.4. Wholesale Electricity Price and Variable Production Costs

Figure 17 shows the average monthly All-In price of wholesale electricity plotted against the average variable production cost of hypothetical power plants burning either natural gas or oil. Gas plant production costs are based on a gas plant with a heat rate of approximately 7,000, while oil plant production costs are based on a heat rate of approximately 10,000. Variable production costs reflect day-ahead spot market prices for fuel. The correlation coefficient of the All-In Price and variable cost of the gas plant is also shown. Figure 17 shows that the All-In Price has been very closely related to generating plants' fuel costs.

Figure 17 – Monthly Average All-In Price vs. Variable Production Costs



5.5. Comparison of Hub RT LMPs with Other Power Pools

This section compares spot market clearing prices in ISO-NE with six other deregulated power exchanges and with prices in the bilateral market. Comparing price levels and price trends among power pools provides a useful measure of the reasonableness of price levels in New England. The RT LMP at the internal Hub is used to represent the New England price. At times, the Hub LMP may include small congestion or marginal loss components, which may be positive or negative. The prices used for PJM and NYISO do not include congestion or losses because these areas report an unconstrained system price.

The prices shown in Table 26 and subsequent exhibits in this section are for March 1- June 30, in US dollars, as follows:

ISO-NE: Real-time LMP at the Internal Hub

PJM: Real-time unconstrained System LMP

Cal-ISO: Real-time clearing prices. Values are the minimum of the two zonal energy prices.

Alberta: Pool Price Energy Price (converted to US dollars)

NYISO: Real-time Reference Bus LBMP

Ontario IMO: Real-time Hourly Energy Price (converted to US dollars)

NordPool: Pool Energy Price (Converted to US dollars)

Table 26 – RT Energy Clearing Price Statistics For Seven Pools, March – June 2003

	Mean	Median	Min	Max	Std Dev
Alberta	$43.17	$28.61	$5.11	$450.07	$47.85
Cal-ISO	$34.20	$31.28	$-18.86	$192.81	$28.63
ISO-NE	$52.53	$48.39	$0.00	$398.60	$25.21
NYISO	$44.62	$43.45	$-33.13	$404.28	$26.33
NordPool	$35.14	$34.55	$5.24	$55.33	$7.57
Ontario IMO	$39.97	$31.98	$10.86	$406.31	$28.91
PJM	$37.97	$29.29	$-5.80	$161.07	$27.06

In Figure 18, energy-clearing prices are grouped into ranges for analysis. The bars show the percentage of hours with clearing prices in each range. During the period, ISO-NE had a higher proportion of prices over $40 than the other North American pools. This is consistent with data from the Interim Markets.

Figure 18 - Pool RT Energy Clearing Price Comparison

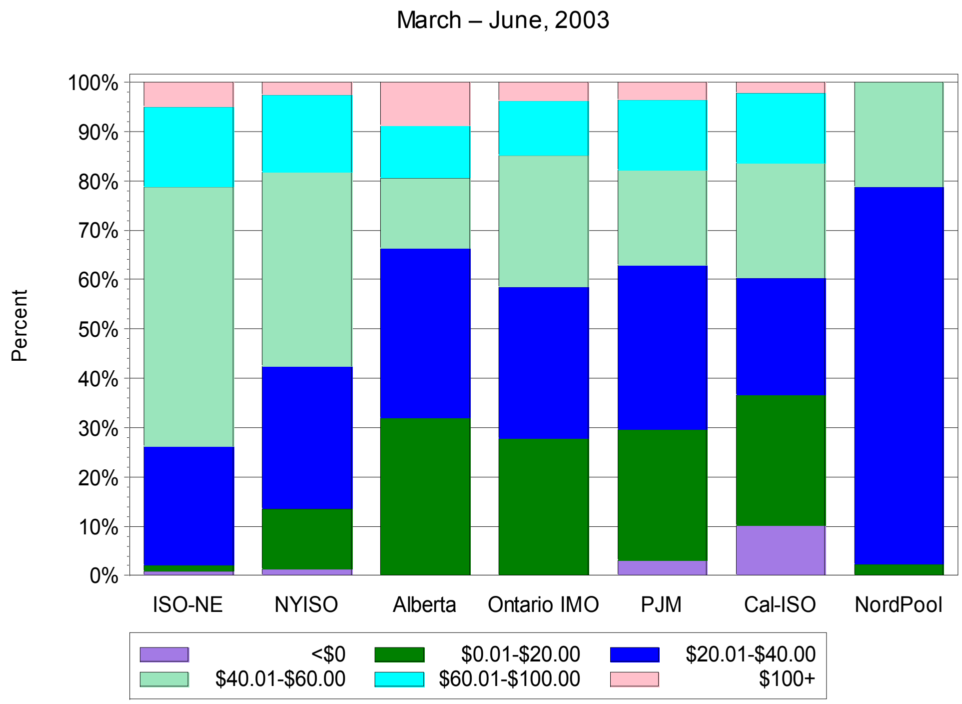


Figure 19 presents average hourly prices for the quarter by day type for the seven pools. Prices were higher in ISO-NE than in the other pools for both weekday and weekend day types.

Figure 20 shows the pattern of weekday RT energy clearing prices, averaged by hour, in ISO-NE and its neighboring power Pools, NYISO and PJM. Energy prices in ISO-NE were higher than those in NYISO and PJM. Figure 21 shows price duration curves for all seven pools.

Figure 19 – Average RT Prices by Day Type, Seven Pools
March-June, 2003

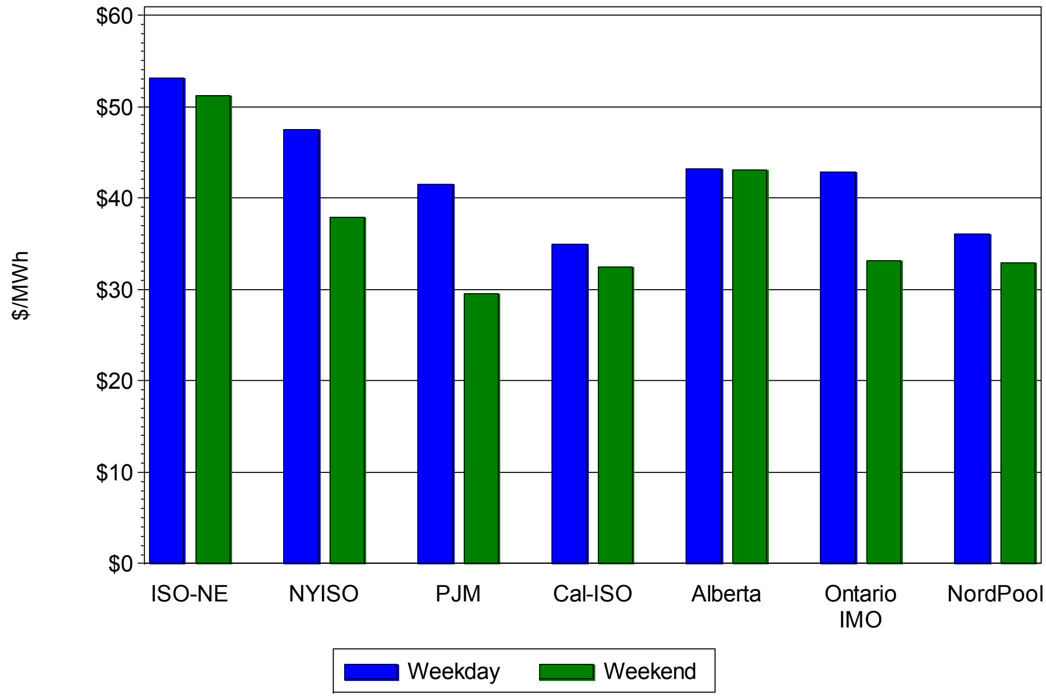


Figure 20 - Average Hourly RT Energy Prices, NE, NY and PJM
Weekdays, March-June, 2003

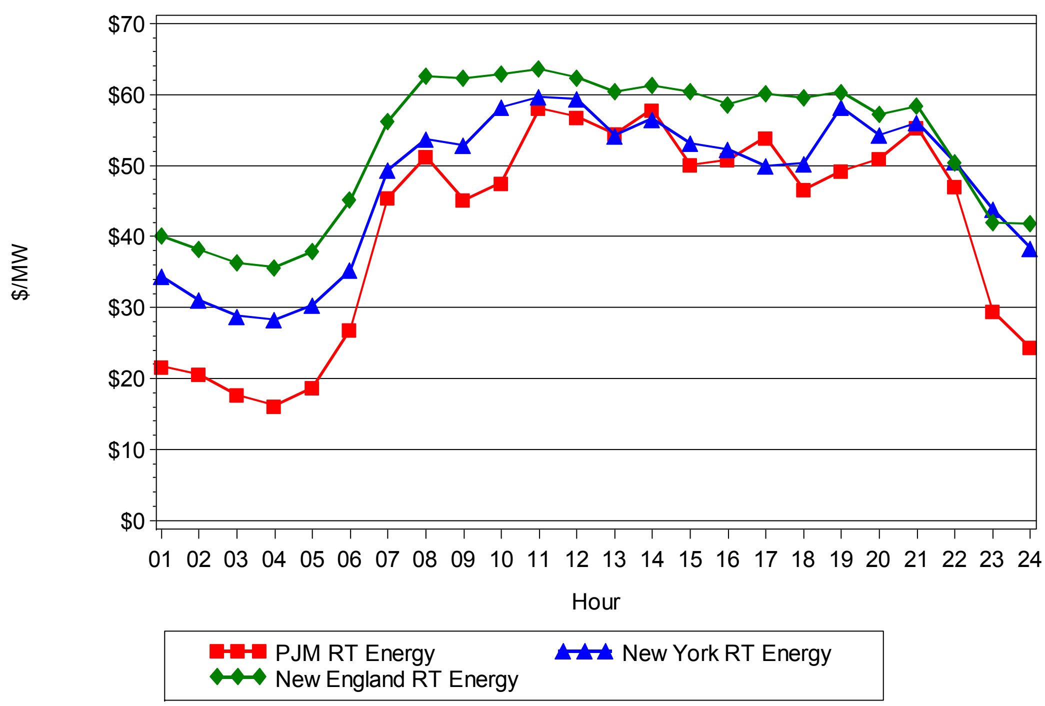
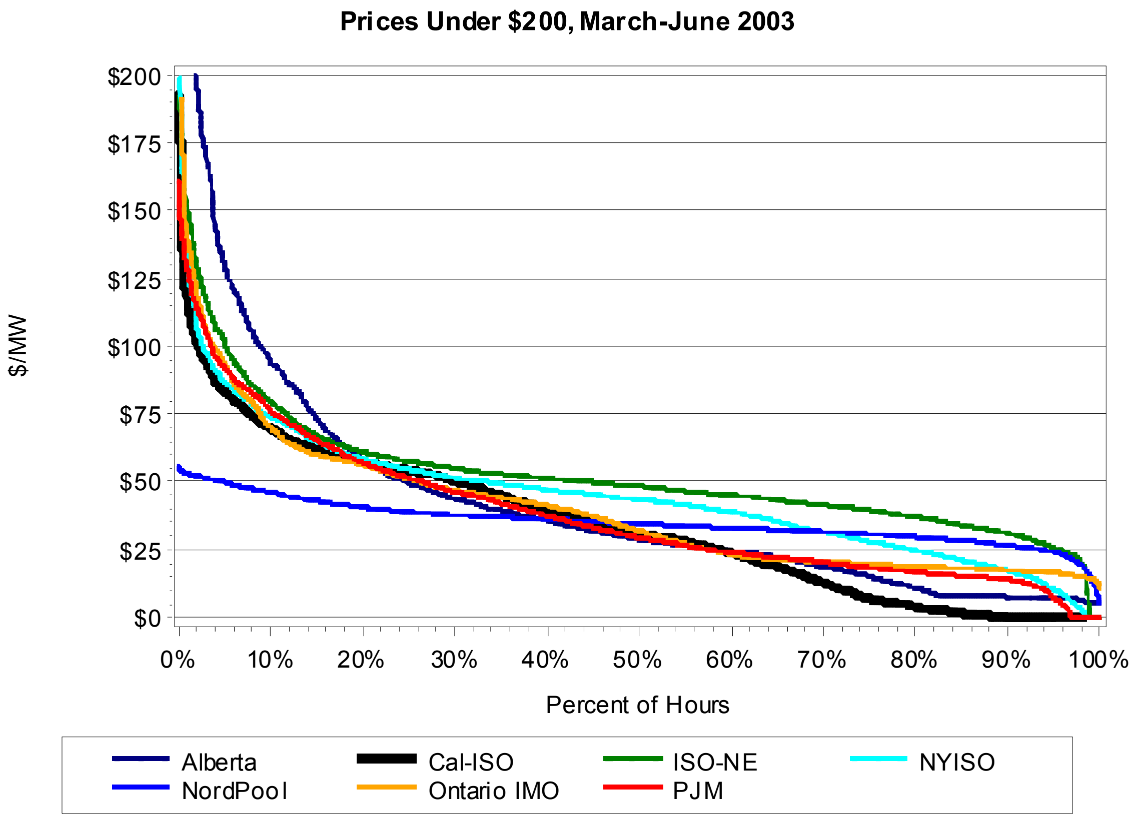
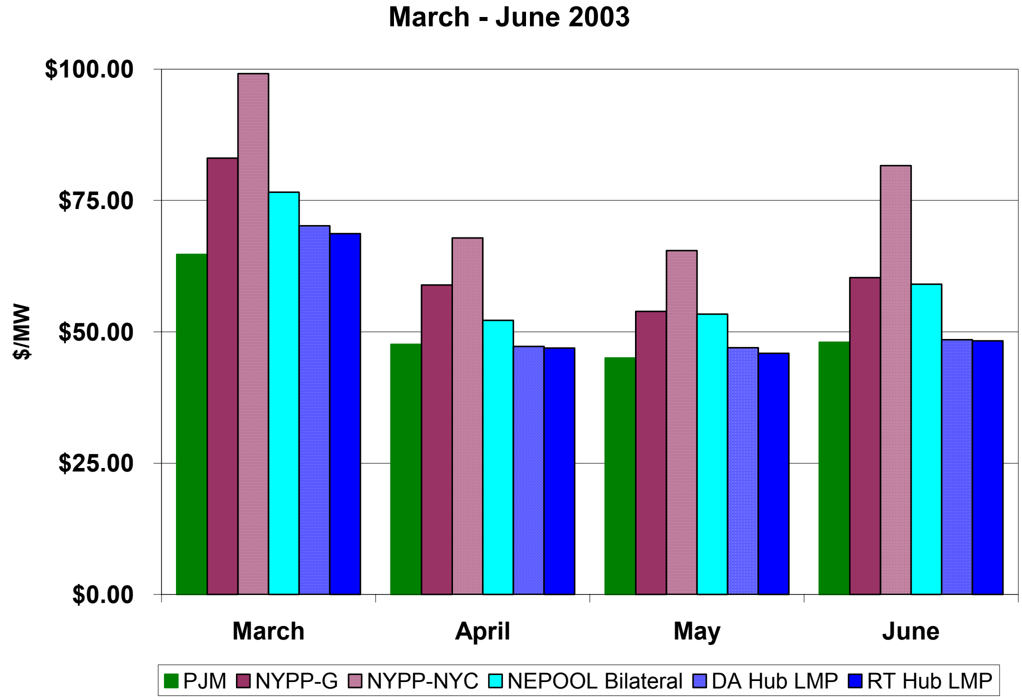


Figure 21 – Price Duration Curves for Seven Pools



ISO-NE administers the actual flow of electricity in several bilateral markets, but the prices of these flows are not known to ISO-NE. Prices are available only through news and research organizations. Figure 22 compares New England, New York, and PJM day-ahead bilateral prices (secured from a third party vendor) with the ISO-NE DA and RT Hub LMPs. All prices are weekday, on-peak averages for the quarter. The New York bilateral prices shown are for the Hudson Valley (Zone G) and New York City (Zone J) areas only.

Figure 22 – On-Peak Bilateral Pricing, DA and RT LMPs



PJM, NYPP, and NEPOOL Bilateral Prices © 2003 Energy Argus Inc.

5.6. Marginal Price Setting Analysis

Price setting under SMD is different than under the Interim Markets. Under the Interim Markets, the Real-Time Marginal Price (RTMP) was the price of the least expensive MW that could be dispatched above the Desired Dispatch Points (DDP), taking into account each Generator's penalty factor (increasing cost with increasing distance from load), Operational Flag(s), and other limits. For each hour, the Energy Clearing Price (ECP) was the time-weighted average of the RTMP calculations made during the hour. The resource that was associated with the marginal price was called the RTMP setter.

Under SMD, the ISO calculates Real-Time LMPs on an ex-post basis using actual system conditions and the eligibility of a generator, dispatchable load, or external transaction to set the LMP. The ISO determines the least cost security-constrained dispatch, which is the least costly means of serving load at all locations in the NEPOOL Control Area, based on the actual operating conditions that existed on the power system and on the prices of resources eligible (by the market rules) to set LMP. LMPs for generation and load nodes in the NEPOOL Control Area and external nodes are calculated based on the actual economic Dispatch and the eligible Resource Supply Offer prices.

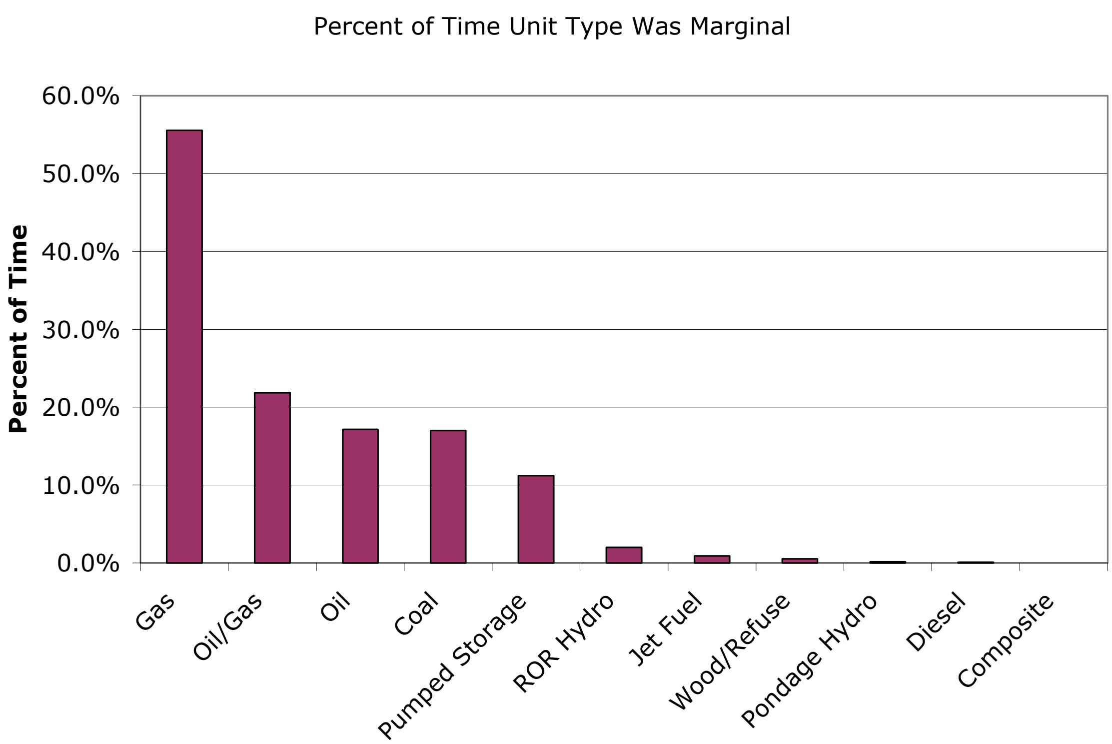
In performing the LMP calculation, the ISO calculates, using the security-constrained Unit Dispatch Software (UDS), the cost of serving an increment of load at each bus from eligible Resources. This is computed as the sum of the price at which a Participant offers to supply or reduce an additional increment of energy from eligible Resources and the effect on transmission line loadings, congestion costs and marginal transmission losses (positive or negative) associated with increasing or decreasing the output of the eligible Resource.

The eligible Resource(s) that can service an increment of load at a bus at the lowest cost determines the LMP at that bus. The calculation is performed every five minutes, using the UDS, which produces a set of LMPs based on system conditions at a specific instant in time. The prices produced at five–minute intervals during an hour are integrated on a time-weighted basis to determine the LMP for that hour.

The analysis presented below is a summarization of the ISO's UDS system runs (approximately 47,000 runs) during the quarter. During the "look-ahead" phase of UDS operation, the system identifies and flags the generator, dispatchable load, or external transaction that is "marginal," i.e., the resource that can supply a MW increment at each of the over 900 locations throughout the system. Binding RT transmission constraints can (and have) produce(d) instances where there is more than one marginal unit on the system. Each marginal unit is included in the analysis. Also, external transactions are not considered in this analysis.

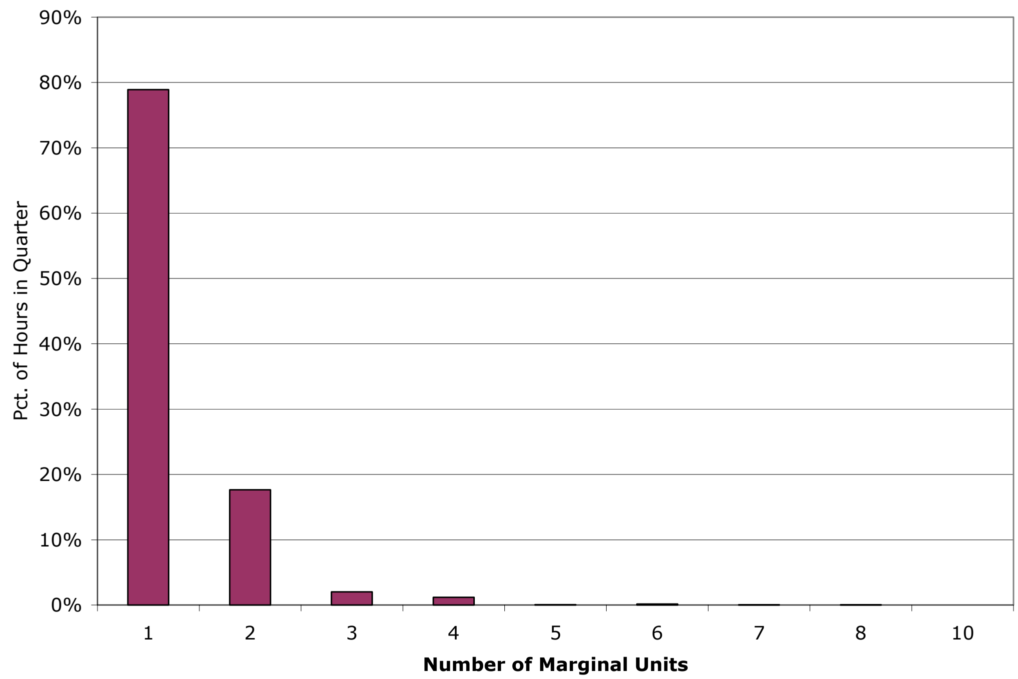
Figure 23 shows that units burning natural gas were marginal almost 56% of the time (approx. 1,630 hours) during the quarter. This is roughly equal to the combined amount of time the next three unit types (oil/gas, oil, and coal) were marginal. These results are consistent with recent experience under the Interim Markets.

Figure 23 – Marginal Unit(s) by Unit Type



As mentioned previously, the LMP calculation respects the limits of the power system. If serving an incremental MW at a location creates a binding constraint, the UDS system calculates the dispatch solution that can meet the incremental demand at the lowest cost function while respecting line limits. These binding constraints can produce multiple units that are marginal. Figure 24 below shows that almost 80% of the time there was one marginal unit, indicating a general lack of congestion on the system.

Figure 24 – Number of Marginal Units: Total Time in Quarter

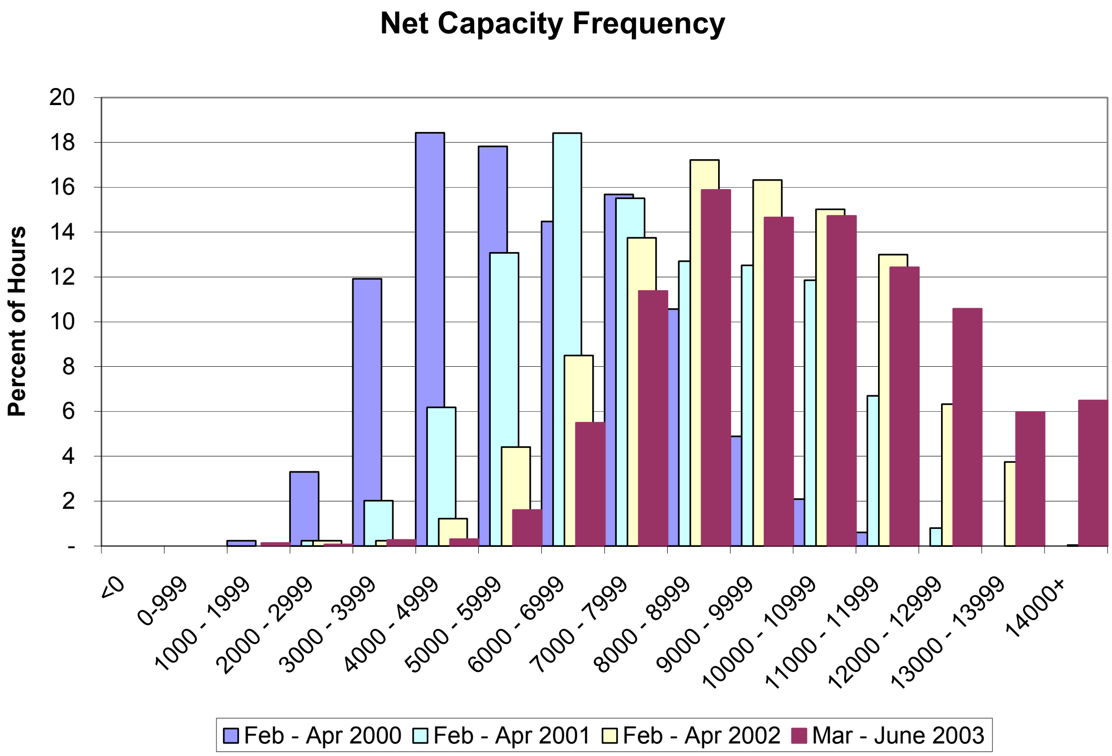


5.7. Supply and Demand

The total MW capacity available is the sum of all New England generators' Economic Maximum limits, plus available capacity from external contracts, minus exports. Many of the available external contracts do not flow regularly because their prices are higher than those of available internal resources. The external contract capacity reported here is limited to the amount for which there is import capacity (i.e., transfer limits). Total capacity does not include unavailable units or possible emergency purchases.

In Figure 25, load and operating reserve requirements are subtracted from total capacity and the net, or excess, capacity is reported as a frequency for the peak load hour of each day in the quarter for the entire pool. As described earlier, the definition of 'quarter' is changing. For this reason, Q2 2003 is compared to the February – April timeframe from previous reports. It is evident from this plot that the available net capacity on the system has grown markedly over the last four years.

Figure 25 – Net Capacity Frequency, Quarterly History



5.8. Spot Market Activity

The Multi-Settlement Energy Market and LMP pricing complicate the analysis of the "spot market." At its highest level and independent of market design features, the spot market serves to balance the financial positions of Market Participants taken prior to real-time operations against the actual energy volumes produced and consumed in real-time.

Under the Interim Markets, Adjusted Net Interchange (ANI) was calculated for all Market Participants. The ANI calculation netted Participant generation entitlements and contract purchases against their real-time consumption and contract sales. Negative ANI resulted in that Participant paying the product of its negative ANI and the real-time, pool-wide price. Conversely, positive ANI resulted in a payment to the participant at that same hourly price.

The advent of SMD has increased the granularity of the ANI calculation. Under this market design, each Participant has an ANI at every location in the system (approximately 900) in both the DA and RT markets.

A Participant's DA ANI at a location is calculated as:

DA ANI = (Cleared Generation Offers + Cleared Increment Offers + Cleared Imports)
– (DA Cleared Demand Bids + Cleared Decrement Bids + Cleared Exports
+ DA Bilateral Transactions)

A Participant's RT ANI at a location is calculated as:

RT ANI = (Metered Generation + Scheduled Imports) – (Metered Load + Scheduled Exports + DA and RT Bilateral Transactions)

Finally, a Participant's RT ANI Deviation is calculated as:

RT ANI Deviation = RT ANI – DA ANI

Market Participant strategies and the locational aspect of pricing make quantification of the spot market more challenging under SMD. One way to express the spot market is to show, summed over Participant, location, and hour, each of the DA ANI, RT ANI, and the RT ANI Deviation. Each of these concepts related to the Average Hourly RT Load Obligation – a proxy for system-wide demand – proves useful in tracking spot market activity. Table 27 below shows the average amount of hourly negative ANI for each of the concepts over the quarter. A Participant's Negative ANI at a location indicates that, at the time of market settlement (DA and/or RT), the Participant is utilizing the spot market, either intentionally or unintentionally.

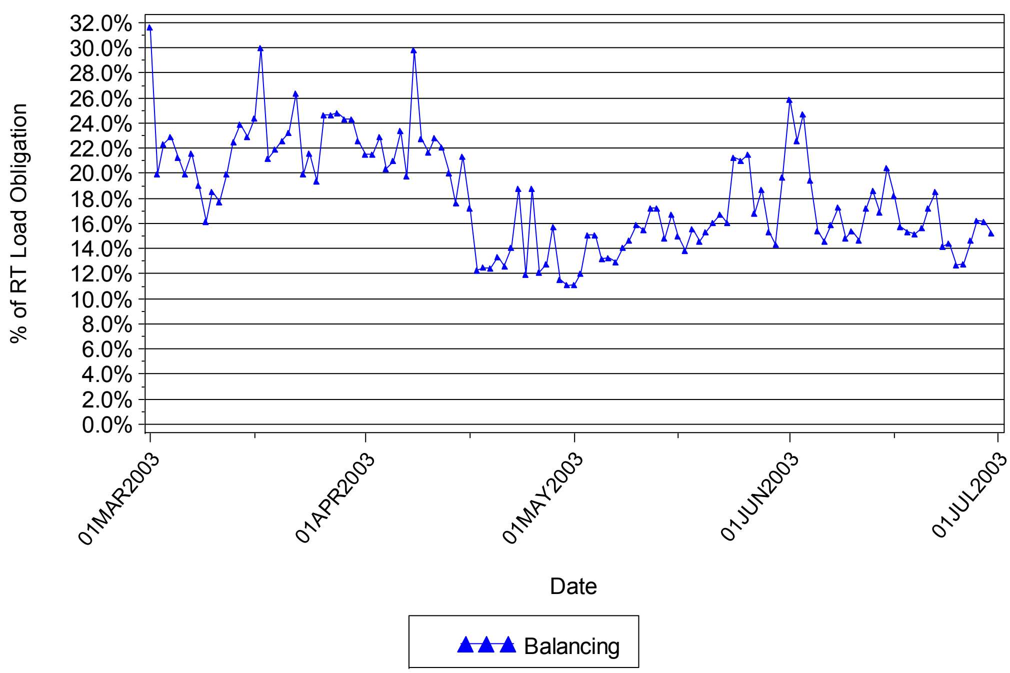
Because Participants take positions at locations in both the DA and RT markets, DA and RT ANI can tend to overstate spot market volumes. For this reason, we concentrate on Negative RT ANI Deviation (the net of DA and RT market operations) as the spot market measure. This value is slightly higher in the off-peak hours, but over the quarter has trended downward – perhaps indicating increasing skill of the Participants in managing their operations.

Table 27 – Average DA ANI, RT ANI, and RT ANI Deviation for the Quarter

On/Off Peak	Month	Avg Hourly RT Load Oblig (MWh)	Avg Hourly Neg DAANI (MWh)	Avg Neg DAANI%	Avg Hourly Neg RTANI (MWh)	Avg Neg RTANI%	Avg Hourly Neg RTANI Dev (MWh)	Avg Neg RTANI Dev%
All	All	14,431.2	3,805.10	26.4%	3,768.1	26.1%	2,640.7	18.3%
On-Peak	*All*	*16,512.1*	*4,271.70*	*25.9%*	*4,185.0*	*25.3%*	*2,897.5*	*17.5%*
Off-Peak	All	12,625.2	3,400.20	26.9%	3,406.2	27.0%	2,417.9	19.2%
On-Peak	*March*	*16,620.6*	*5,215.80*	*31.4%*	*4,613.9*	*27.8%*	*3,673.8*	*22.1%*
On-Peak	*April*	*16,478.7*	*3,986.20*	*24.2%*	*4,127.7*	*25.0%*	*2,919.8*	*17.7%*
On-Peak	*May*	*15,701.9*	*3,922.00*	*25.0%*	*4,086.0*	*26.0%*	*2,273.4*	*14.5%*
On-Peak	*June*	*17,248.8*	*3,976.50*	*23.1%*	*3,915.1*	*22.7%*	*2,721.9*	*15.8%*
Off-Peak	March	13,290.8	3,817.60	28.7%	3,789.5	28.5%	3,019.2	22.7%
Off-Peak	April	12,660.6	3,471.10	27.4%	3,458.2	27.3%	2,358.1	18.6%
Off-Peak	May	11,751.0	2,971.00	25.3%	3,116.6	26.5%	2,017.7	17.2%
Off-Peak	June	12,813.0	3,344.90	26.1%	3,257.1	25.4%	2,261.3	17.6%

The balancing (RT ANI Deviation) volume as a percent of RT Load Obligation is shown in Figure 26 below. This figure also shows the downward trend over the quarter; however, there are some notable spikes in this series. The up tick at the beginning of June occurred at a time of very low demand on the system.

Figure 26 – Daily RT ANI Deviation
As Daily Percent of RT Load Obligation
March - June 2003

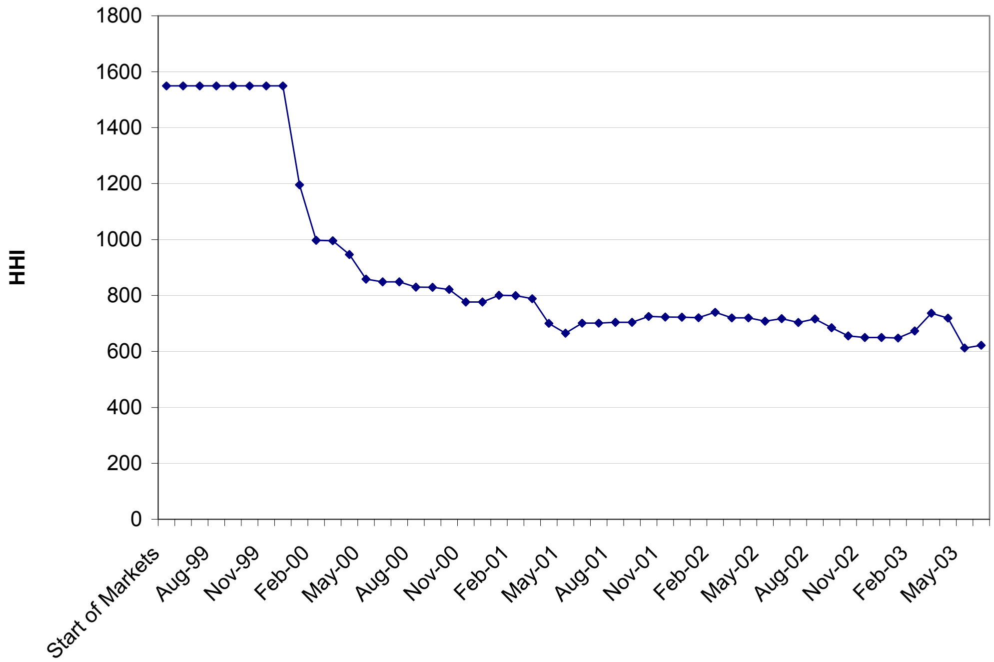


5.9. Market Concentration Measures

A widely used measure of market concentration is the Hirschman-Herfindahl Index (HHI), calculated as the sum of the squares of the market shares of the firms in a market. Although a low concentration index does not guarantee that a market is competitive, higher values are indicative of greater potential for the exercise of market power by participants. A market with an HHI above 1800 is generally considered highly concentrated.

Figure 27 shows the HHI for New England internal resources, based on summer capabilities. The values shown were developed from information secured from each of the participants by the ISO Market Monitoring and Mitigation group. The market-wide HHI shows a steady decline since the opening of wholesale electricity markets, with a slight up-tick in the winter of 2002/2003 due to a reclassification of certain customers.

Figure 27 – Hirschman-Herfindahl Indices (HHI)
From Beginning of Markets to June 2003



6. Load and Supply Conditions

6.1. Loads, Energy, and Weather

6.1.1. Average Loads, Energy, and Weather

System average hourly load increased almost 5% during the months of March and April 2003 over the comparable period last year and can be attributed to the approximately 8% lower average temperature. The temperature difference was not nearly as marked during the May and June time period, resulting in less than a 1% increase in system-wide average hourly load. Table 28 summarizes the average load and temperature data for the period.

Table 28 – System Average Load and Weather Comparison

	Mar-Apr '02	Mar-Apr '03	Change	% Chg.	May-Jun '02	May-Jun '03	Change	% Chg.
System Average Load								
MW	13,585	14,236	650	4.8%	13,720	13,826	106	0.8%
Average Dry Bulb Temperature ºF								
NE Wtd Avg.	43.3	39.6	-3.7	-8.5%	60.4	59.8	-0.6	-1.0%
ME	39.5	36.3	-3.1	-8.0%	56.9	57.3	0.3	0.6%
NH	40.3	36.4	-3.9	-9.7%	58.5	59.5	1.0	1.7%
VT	39.5	36.1	-3.5	-8.8%	58.8	60.7	1.8	3.1%
CT	45.3	41.4	-3.9	-8.6%	62.1	61.5	-0.6	-1.0%
RI	45.1	41.4	-3.8	-8.4%	61.4	59.8	-1.6	-2.6%
SEMA	45.1	41.4	-3.8	-8.4%	61.4	59.8	-1.6	-2.6%
WCMA	41.6	38.4	-3.2	-7.7%	58.5	58.5	0.0	0.0%
NEMA	44.5	40.5	-3.9	-8.9%	61.5	59.6	-1.9	-3.1%

Table 29 shows the recorded and weather normalized NEPOOL Net Energy for Load (NEL) values for the quarter. NEL is defined as the sum of metered generation and net external tie line flows less the amount of energy used for pumping at New England's pumped storage hydro facilities. NEL rose 2.3% for the quarter on a recorded basis. After factoring the effect of weather, NEL rose slightly more than 1%.

Table 29 – NEPOOL Monthly Recorded and Weather Normalized Net Energy

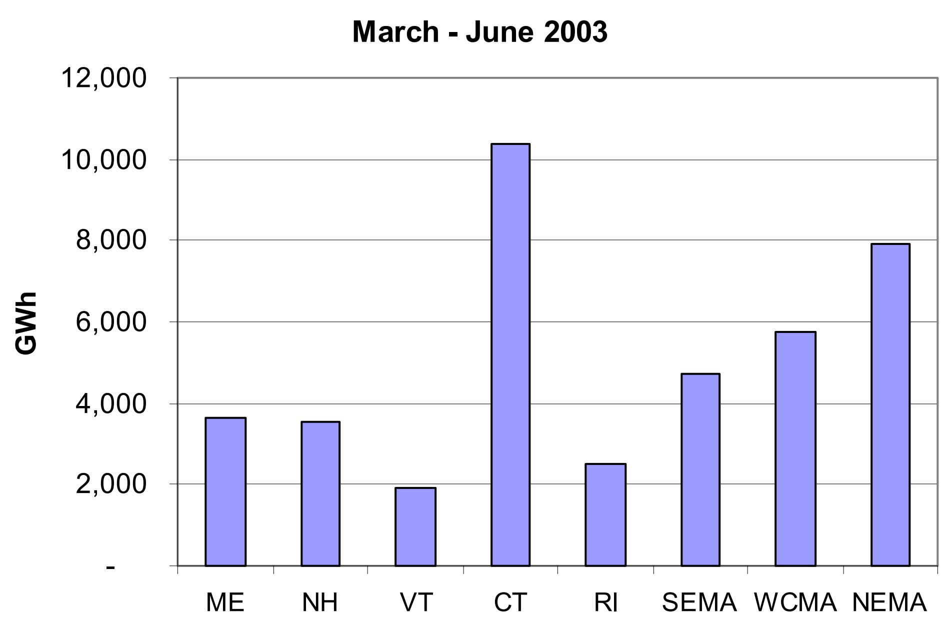
	Recorded NEL (GWh)			Wthr. Normalized NEL (GWh)		
	2003	2002	%Var.	2003	2002	%Var.
March	10,882	10,373	4.9%	10,870	10,484	3.7%
April	10,009	9,623	4.0%	9,822	9,615	2.2%
May	9,761	9,843	-0.8%	9,568	9,692	-1.3%
June	10,481	10,382	1.0%	10,481	10,487	-0.1%
Quarter	41,133	40,221	2.3%	40,740	40,278	1.1%

Table 30 shows energy consumption for the quarter by load zone. The values differ slightly from the total shown in Table 29 due to the non-inclusion of losses in these values. Nearly 75% of the energy in New England was consumed in the five southern load zones (Connecticut, Rhode Island, Western/Central Massachusetts, Southeastern Massachusetts, and Northeastern Massachusetts/Boston.) This is portrayed graphically in Figure 28.

Table 30 – Monthly Demand by Load Zone

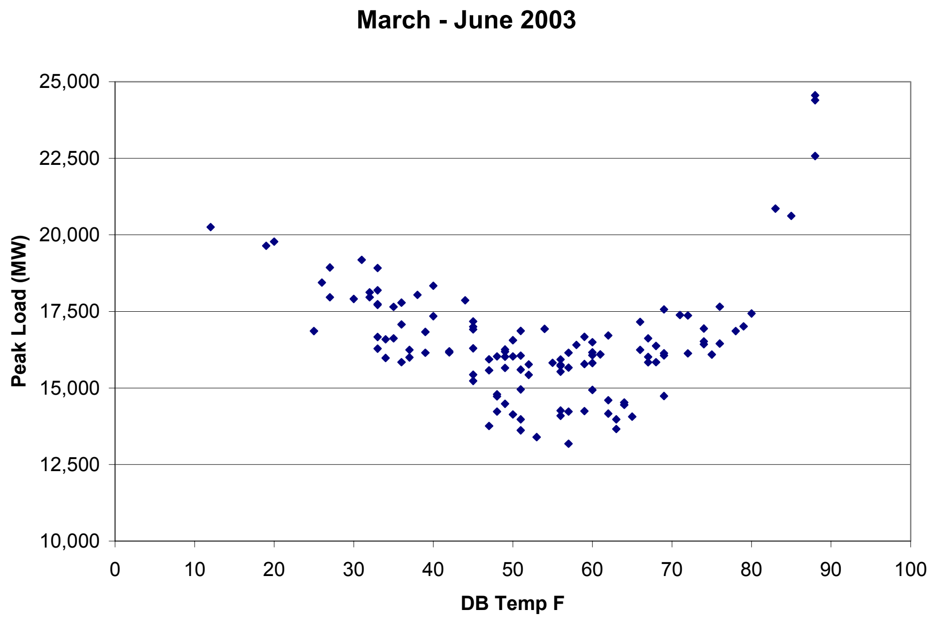
	Energy (GWh)								
	NEPOOL	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
March	10,715	964	941	525	2,765	660	1,245	1,509	2,105
April	9,765	903	851	426	2,500	613	1,149	1,395	1,929
May	9,620	878	844	463	2,447	603	1,135	1,370	1,880
June	10,307	917	908	480	2,661	653	1,215	1,456	2,017
Quarter	40,407	3,662	3,544	1,894	10,373	2,529	4,744	5,730	7,931
% of Total	100.0	9.1	8.8	4.7	25.7	6.3	11.7	14.2	19.6

Figure 28 – Total Demand for the Quarter by Load Zone



The second quarter included both heating and cooling-driven system peak demand. Figure 29 below shows the relationship between daily peak loads and the dry bulb temperature for the quarter.

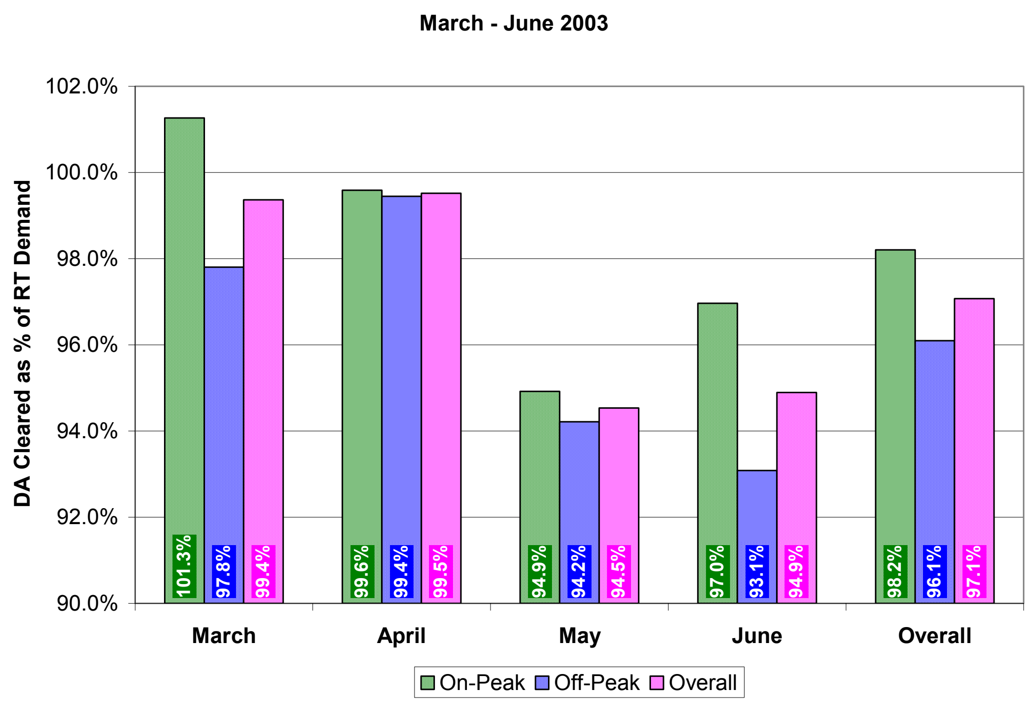
Figure 29 – Daily Peak Loads vs. Dry Bulb Temperature



6.1.2. Cleared Demand, On-Peak and Off-Peak

Figure 30 below shows the relationship of New England DA cleared demand (fixed demand, price sensitive demand, and virtual demand) to RT demand for each month during the quarter. Overall, 97.1% of RT demand cleared in the DA market during the quarter.

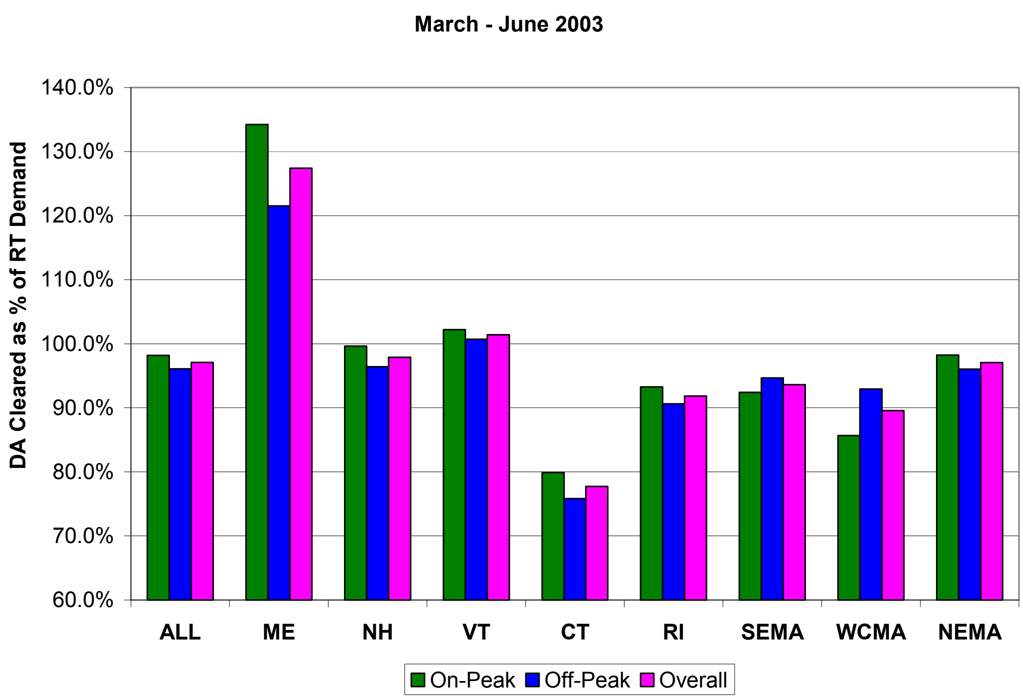
Figure 30 – New England Cleared DA vs. RT Demand by Month



6.1.3. Cleared DA Demand vs. Actual Demand

On a zonal level, the amount of DA cleared demand vs. RT demand varies widely. Figure 31 below demonstrates graphically that, on average, the Maine Load Zone cleared over 127% of RT demand during the quarter, with upwards of 134% being cleared in the on-peak hours. This is attributable to virtual bidding strategies in support of certain contractual arrangements, and was trending downward by quarter's end. By contrast, the Connecticut Load Zone saw DA cleared demand average 75-78% of RT demand – directly attributable to Participants' bidding strategy and contractual position.

Figure 31 – DA Cleared vs. RT Demand by Load Zone



6.1.4. Imports and Exports with Neighboring Control Areas

Figure 32 shows total hourly imports from and exports to New York along with the rolling one-day average net interchange. Exports to New York were highest during weekday, on-peak hours.

Figure 32 – Imports and Exports with New York

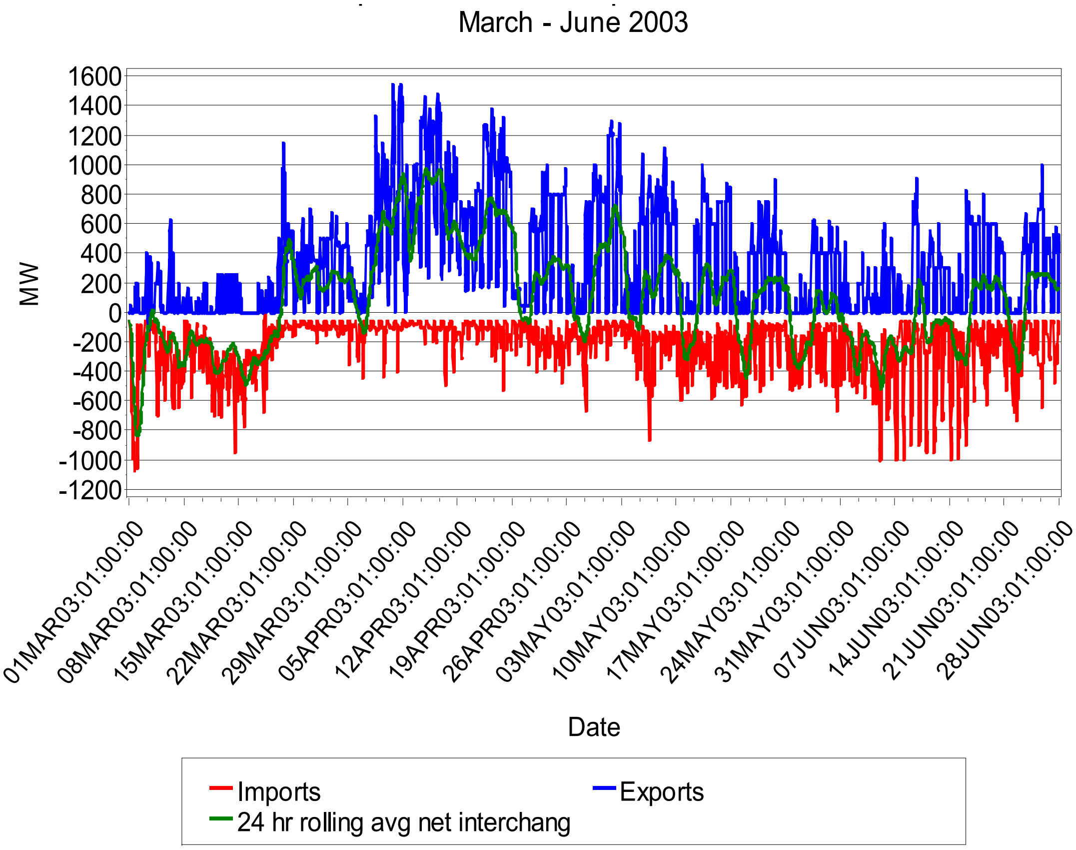
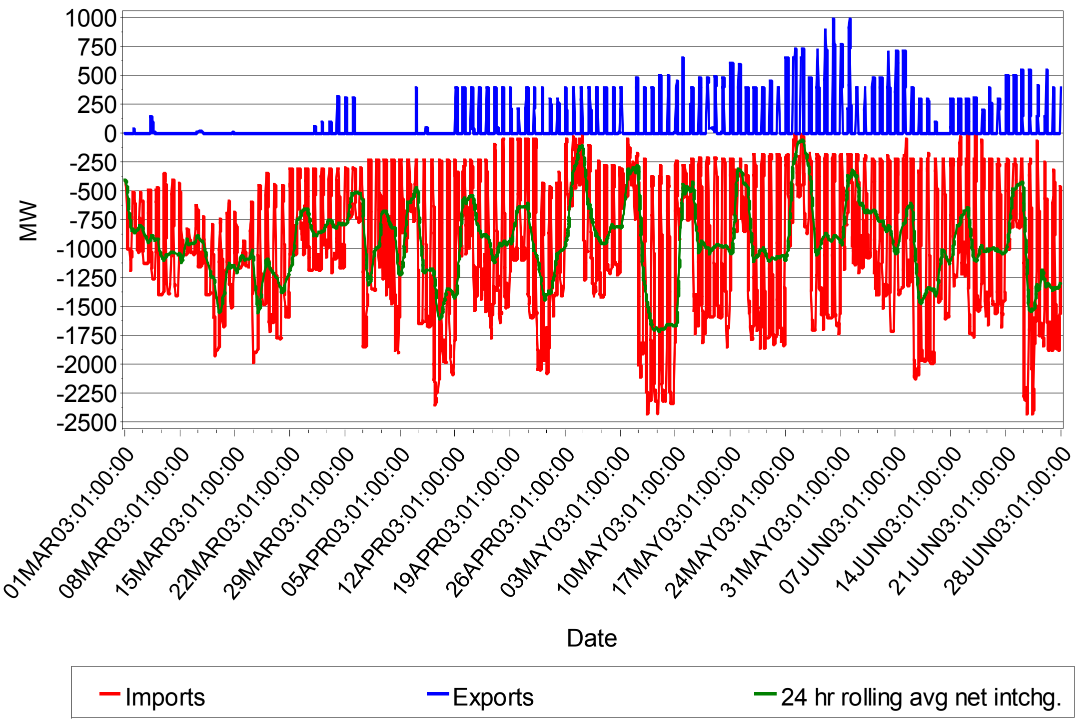


Figure 33 shows total hourly imports from and exports to Canada (HQ and New Brunswick) along with the rolling one-day average net interchange. New England is a net importer of power from Canada, with imports being highest during weekday, on-peak hours. The vast majority of imports are from HQ, while exports are almost exclusively to NB.

Figure 33 – Imports and Exports with Canada

March - June 2003



6.1.5. Net Capacity and All-In Price

The total MW capacity available is the sum of all New England generators' Economic Maximum limits, plus available capacity from external contracts, minus exports. Many of the available external contracts do not flow regularly because their prices are higher than those of available internal resources. The external contract capacity reported here is limited to the amount for which there is import capacity (i.e., transfer limits). Total capacity does not include out-of-service units or possible emergency purchases.

In Figure 34, load and operating reserve requirements are subtracted from total capacity and the net, or excess, capacity is reported for the peak load hour of each day in the quarter. In Figure 35, the All-In Price of wholesale electricity and net capacity for each hour are plotted for each month in the quarter. A negative relationship between net capacity and the All-In Price is evident in each month. That is, the All-In price is higher when less capacity is available to the system – an economically rational outcome. The two distinct clusters of observations occurring during March is the result of significant changes in fuel prices during the course of the month.

Figure 34 – Average Net Capacity in Daily Peak Hours, Q2 2003

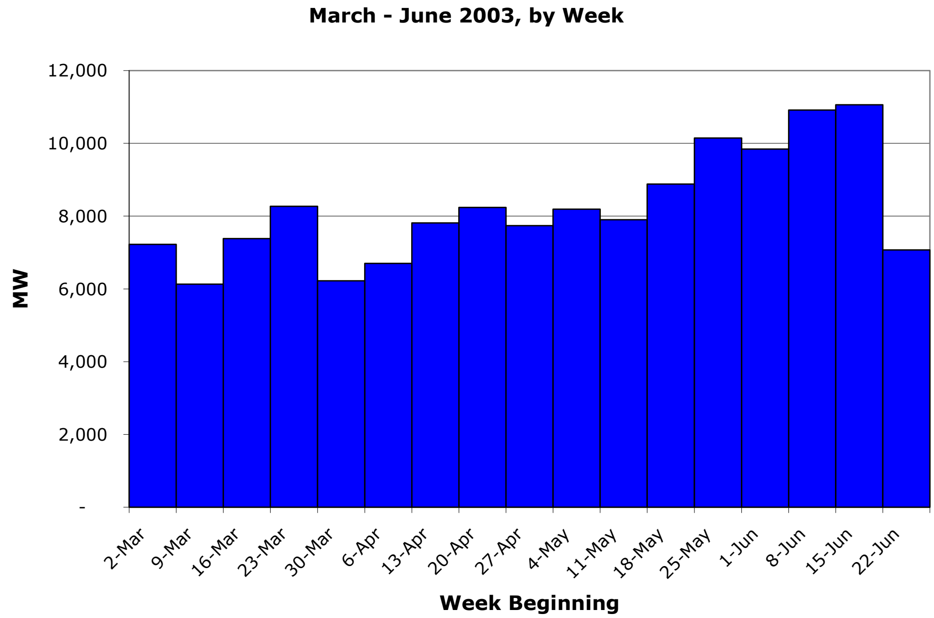
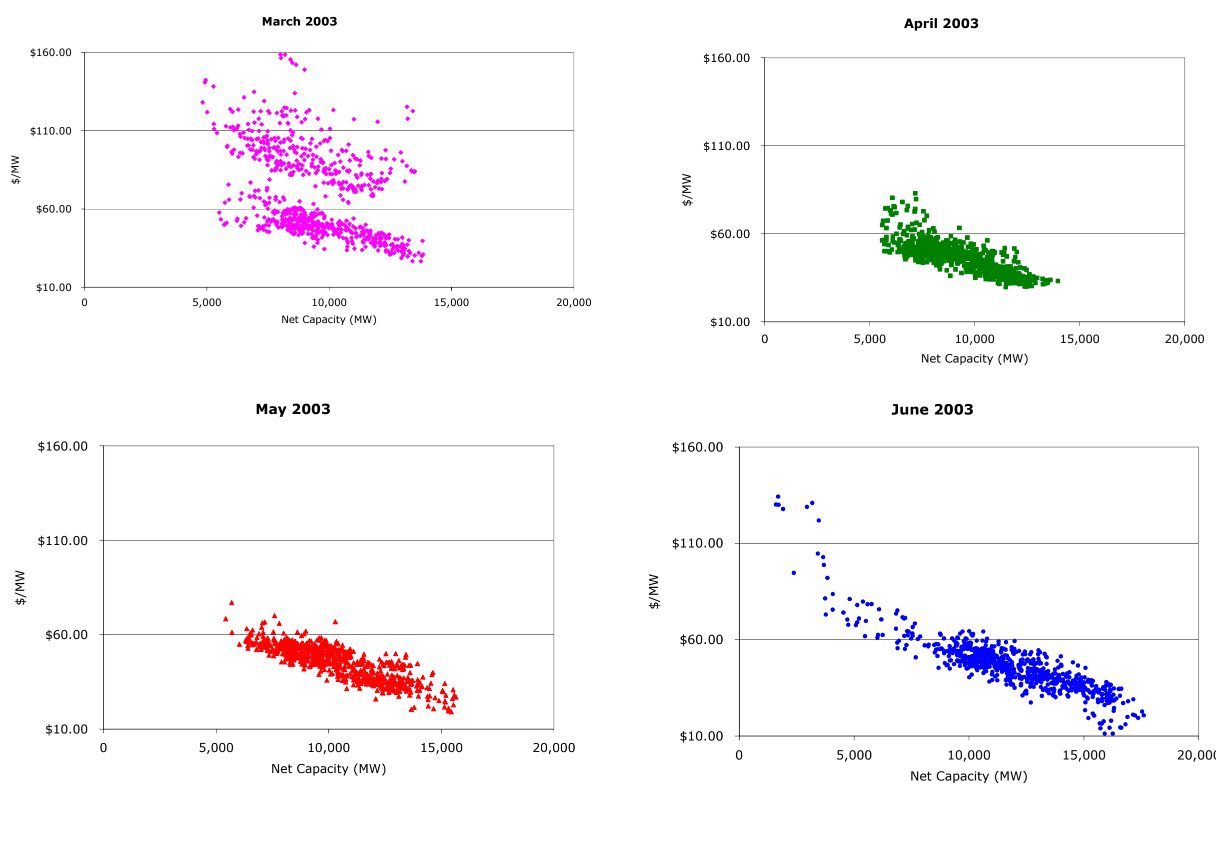


Figure 35 – All In Price of Wholesale Electricity and Net Capacity Correlation



6.2. Transmission

6.2.1. Net Power Flows on Transmission Interfaces

The exhibits on the following pages show box-and-whisker plots for net energy flow on eight transmission interfaces for November 2002-April 2003. These exhibits are designed to show trends in the magnitude and direction of power flows across major transmission interfaces within New England. Figure 36 describes how the statistics are presented in each exhibit. Figure 37 presents a series of graphs that document the observed flows on major transmission interfaces in the region. Trending this information over an extended period is useful in understanding predominant power flows within New England and between New England and its neighbors.

Analysis of the eight graphs that comprise Figure 37 (encompassing the period November 2002 through April 2003) yields the following high-level observations:

- New England has become a net exporter of power to New York, however, January –March 2003 shows small average net imports from New York.

- Within New England, the location of power sources with respect to where it is consumed is responsible for prevailing flows from:

    - The East (ME, NH, NEMA, SEMA, RI) toward the West (CT, Western MA, VT)

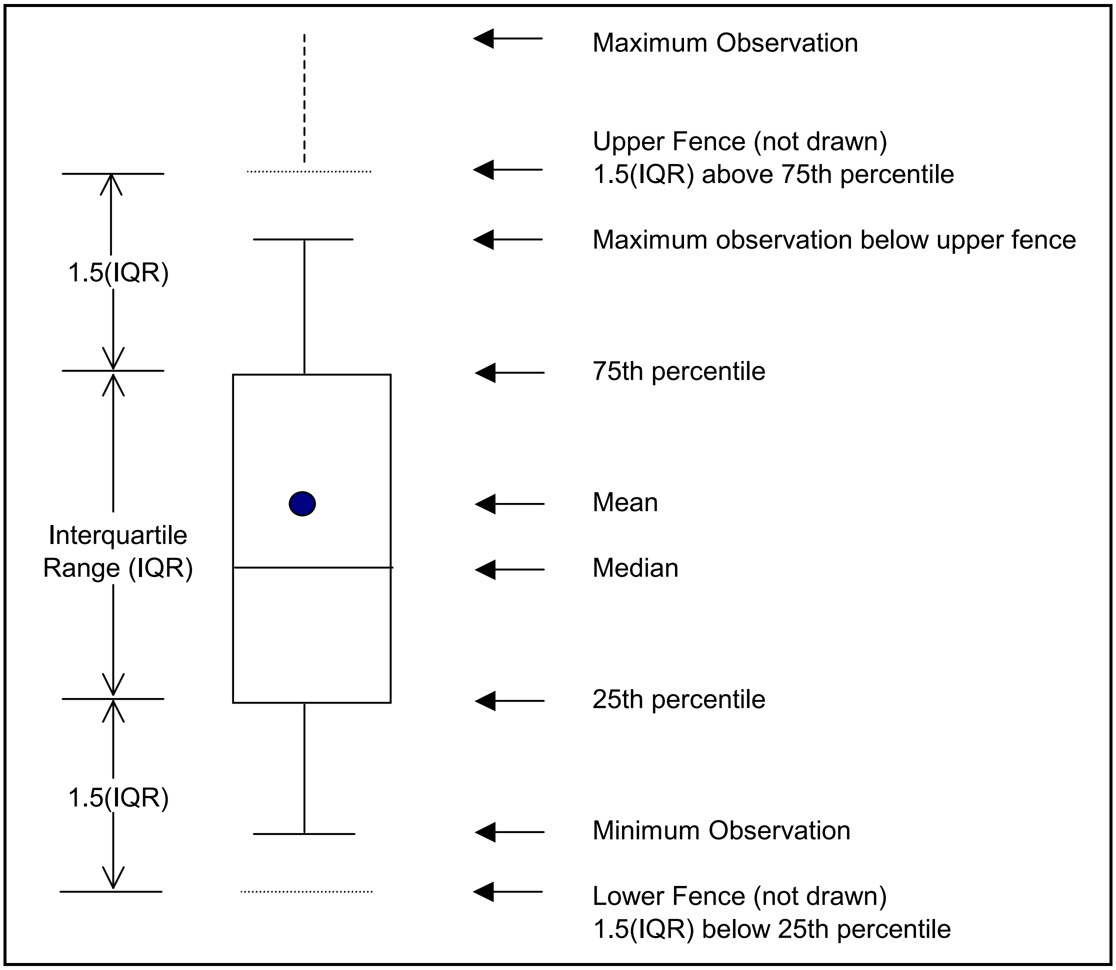
    - The North (VT, NH, ME) toward the South (CT, NEMA, SEMA, RI, WCMA)

    - Maine into New Hampshire

    - SEMA and RI toward NEMA, Boston, and CT (although this situation was reversing itself in March and April due to additions of new generating resources outside of SEMA/RI)

    - Outside Connecticut into that zone, and into Southwest Connecticut from outside that area.

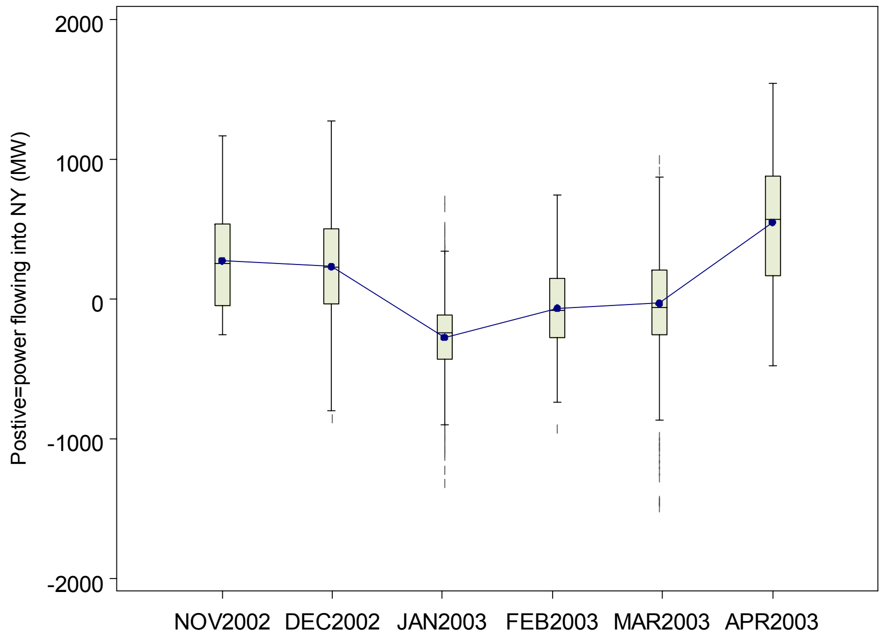
Figure 36 – Diagram of Box Plot Statistics



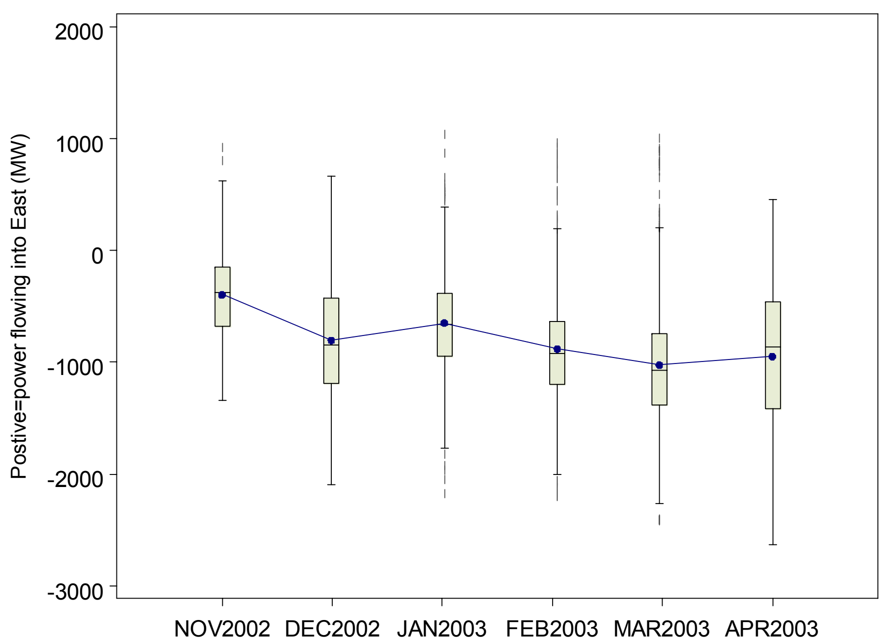
In each exhibit, there is one box plot per month, and megawatt levels are shown on the vertical axis. As the diagram above shows, the dot in the middle of the box represents the average of all flow levels in megawatts during the month. The line bisecting the box represents the median. The top of the box corresponds with the 75th percentile value, while the bottom of the box corresponds with the 25th percentile, so 50% of values are within the box. The difference between the 25th percentile and the 75th percentile is the interquartile range (IQR). Solid lines extend from each end of the box to the value closest to 1.5*IQR. Dashed lines representing outliers extend beyond the 1.5(IQR) markers. There may be no dashed line if there are no outliers, i.e., if the maximum observation is less than 1.5*IQR.

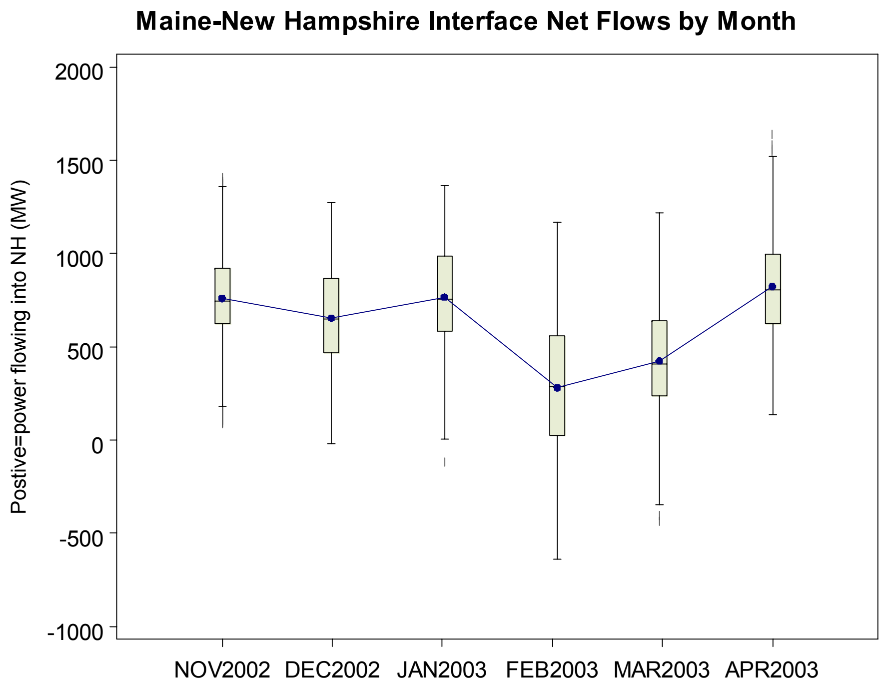
Figure 37 – Major Transmission Interface Flows During the Winter Period

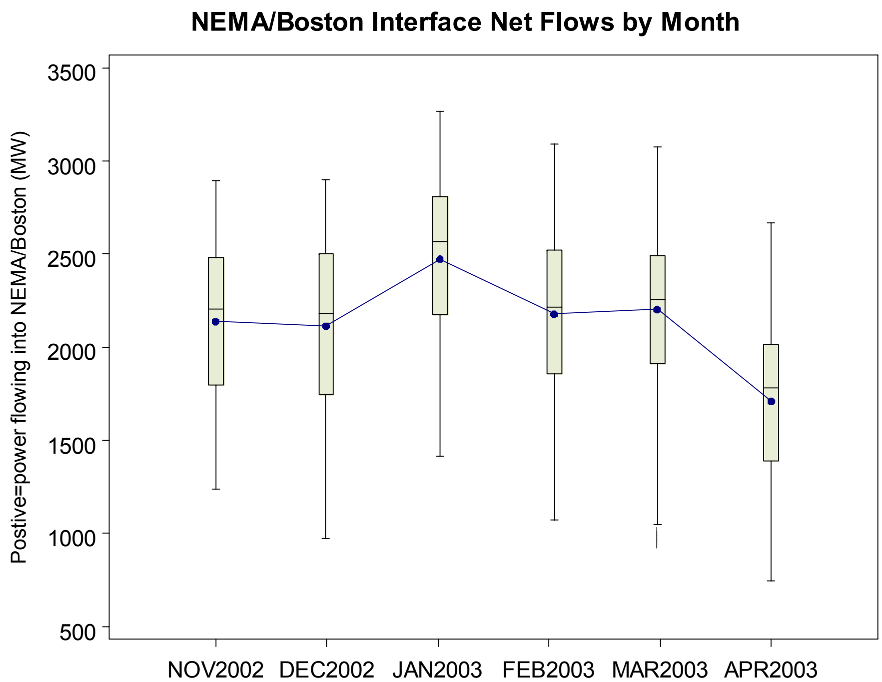
New England-New York Interface Net Flows by Month

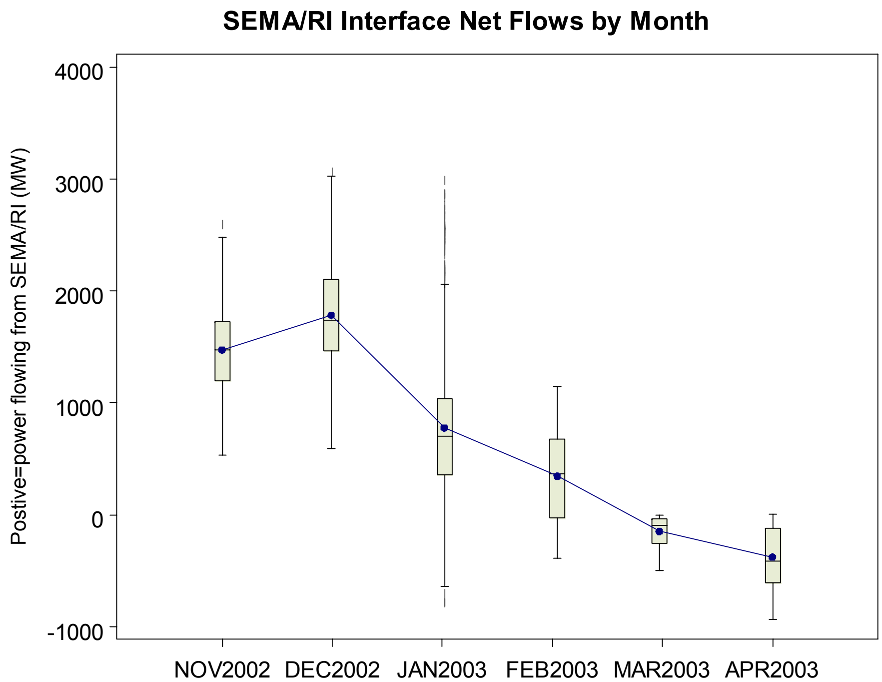


West-East Interface Net Flows by Month

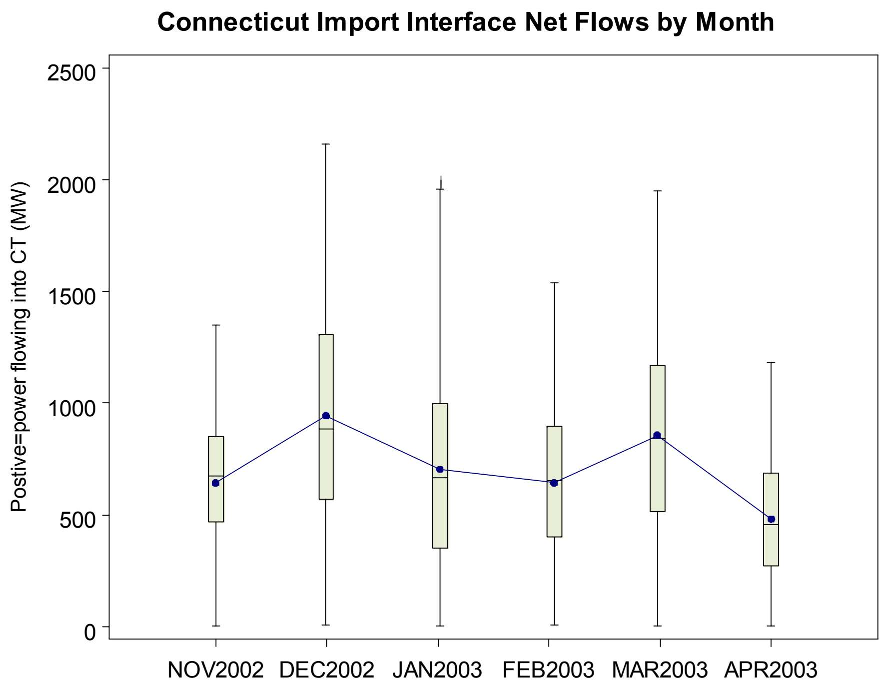



Maine-New Hampshire Interface Net Flows by Month
Postive=power flowing into NH (MW)
2000
1500
1000
500
0
-500
-1000
NOV2002
DEC2002
JAN2003
FEB2003
MAR2003
APR2003


NEMA/Boston Interface Net Flows by Month
Postive=power flowing into NEMA/Boston (MW)
3500
3000
2500
2000
1500
1000
500
NOV2002
DEC2002
JAN2003
FEB2003
MAR2003
APR2003

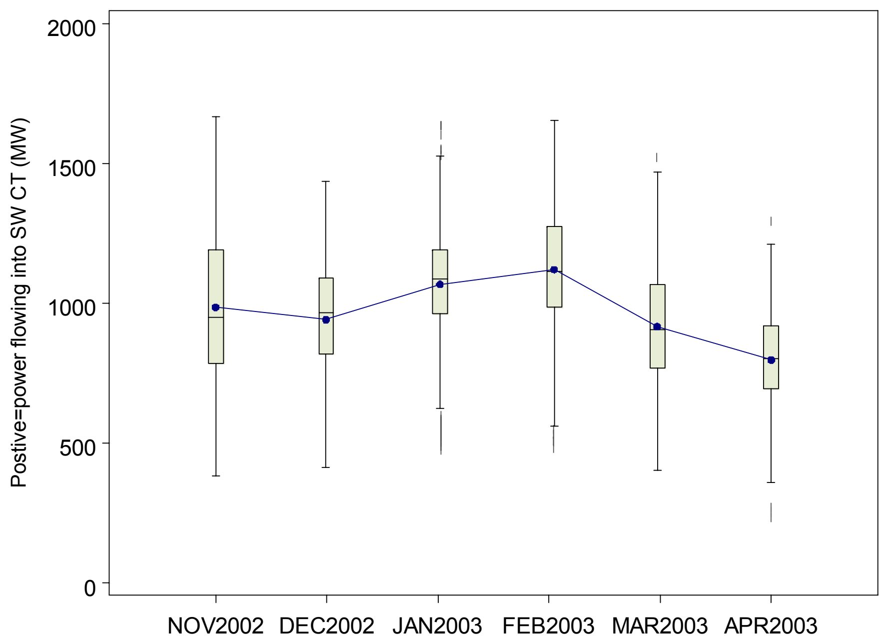


SEMA/RI Interface Net Flows by Month
Postive=power flowing from SEMA/RI (MW)
4000
3000
2000
1000
0
-1000
NOV2002
DEC2002
JAN2003
FEB2003
MAR2003
APR2003

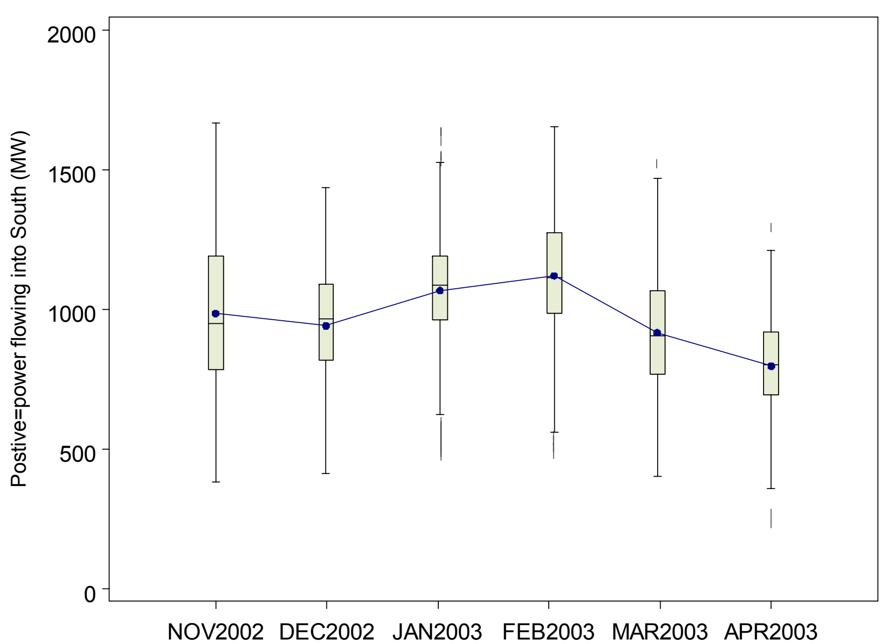


Connecticut Import Interface Net Flows by Month
Postive=power flowing into CT (MW)
2500
2000
1500
1000
500
0
NOV2002
DEC2002
JAN2003
FEB2003
MAR2003
APR2003

Southwest CT Interface Net Flows by Month



North-South Interface Net Flows by Month



6.2.2. DA Transmission Constraints for the Quarter

The DA market is a financial market that clears fixed, price-sensitive, and virtual demand bids against generation, imports and virtual offers. Market clearing occurs within the bounds of the system model that represents New England's transmission system. Transmission constraints can occur in the DA market and result from the patterns of offered supply and bid demand at the hundreds of locations throughout the system. ISO-NE employs a security constrained unit commitment program (SCUC) which has as its objective function the lowest possible production cost for the following day, while respecting the transmission limits of the system.

During the March – June timeframe (2,928 hours), there were a total of 5,646 hourly binding transmission constraints computed in the DA market. Constraints that were binding in at least 1 percent of the total hourly-constrained hours are presented below in Table 31.

Table 31 – DA Transmission Constraints

Constraint Name	Freq	% of Total	% of Hours	Interface	Zone(s)
PV 20	518	9.2%	17.7%	NY/NE	VT
Baker_St 110C PS	411	7.3%	14.0%	Internal to Zone	NEMA
Baker_St 110D PS	408	7.2%	13.9%	Internal to Zone	NEMA
Waltham PS 110E	351	6.2%	12.0%	Internal to Zone	NEMA
Riley_229	345	6.1%	11.8%	Internal to Zone	ME
Waltham PS 110D	331	5.9%	11.3%	Internal to Zone	NEMA
Scobie 326-1	262	4.6%	8.9%	North/South	NH/NEMA
Highgate Import	201	3.6%	6.9%	HQ/NE	VT
Baker_St_110-511-4	132	2.3%	4.5%	Internal to Zone	NEMA
Rumford 228	95	1.7%	3.2%	Internal to Zone	ME
NS_ST	95	1.7%	3.2%	North/South	NH/NEMA/WCMA
NRST	94	1.7%	3.2%	Norwalk/Stamford	CT
Keswick Export	88	1.6%	3.0%	NB/NE	ME
Roseton Export	78	1.4%	2.7%	NY/NE	VT/WCMA/CT
MillburyA127-6	78	1.4%	2.7%	Internal to Zone	WCMA
Bucksprt_86-1	76	1.3%	2.6%	Internal to Zone	ME
Schiller n133-1	74	1.3%	2.5%	Internal to Zone	NH
Baker_St_110-510-4	68	1.2%	2.3%	Internal to Zone	NEMA
Shoreham Export (CSC)	67	1.2%	2.3%	NY/NE	CT
Brighton_110-510-3	66	1.2%	2.3%	Internal to Zone	NEMA
Boston Import	64	1.1%	2.2%	Boston	NEMA
Lvermore_89	61	1.1%	2.1%	Internal to Zone	ME
Prat_J J136S-3	61	1.1%	2.1%	Internal to Zone	WCMA
Canal 1 Limit With 331 Out	58	1.0%	2.0%	Internal to Zone	SEMA
Totals	4,082	5,646	2,928		

7. Monitoring and Mitigation Activity

7.1. Mitigation Activity

7.1.1. Role of ISO-NE

Market Rule 1, Appendix A, *Market Monitoring, Reporting and Market Power Mitigation,* provides for ISO-NE to monitor and, in specifically defined circumstances, mitigate behavior that interferes with the competitiveness and efficiency of the NEPOOL Energy, Regulation, and Operating Reserve markets. As specified in the rule, ISO-NE monitors for defined thresholds of bidding behavior and for market impacts when there is congestion. Whenever one or more of a Participant's bids or declared unit characteristics (1) exceeds specified bid thresholds, and (2) exceeds market impact thresholds, and (3) is not explained by the Participant as consistent with competitive bid behavior, ISO-NE substitutes a Default Bid in place of the bid submitted by the Participant.

7.1.2. Nature and Frequency of Monitoring and Mitigation Activities

During the months of March – June there was limited congestion in the Day-Ahead and Real-Time markets. Congestion mitigation was triggered 4 times during this period. In Table 32, the market in which mitigation occurred is shown.

Table 32 – Instances of Mitigation, March – June 2003

Market	March 2003	April 2003	May 2003	June 2003	Totals
Day-Ahead	0	0	0	0	0
Real-Time	0	0	0	1	1
Regulation	0	0	0	0	0
Operating Reserve	0	1	2	0	3
Totals	**0**	**1**	**2**	**1**	**4**

Under Market Rule 1, Appendix A, Section 3.1.1, consultation with the Participant will occur, whenever practicable, before imposing mitigation. This happened once in the RT Energy Market and three times in Operating Reserve. As a result of the real-time consultation and mitigation, the Participants modified their bidding behavior in the next offer period.

7.2. Resource Audits

Under Market Rule 1, Appendix A, §4.2.2, ISO-NE is authorized to verify forced (unplanned[13]) outages. As such, ISO-NE is tasked with monitoring for physical withholding of a resource, which may include, but is not limited to:

[13] Defined by OP-5 as an unplanned/unexpected outage or derating that cannot be delayed and interrupts operation of the machine.

- Falsely declaring that a resource has been forced out of service or otherwise become unavailable
- Submitting an unjustifiably inflexible set of operating parameters (other than what is listed on the NX-12 (Generator Information Form) so that the resource will not be dispatched
- Operating a generating unit in real-time to produce an output level significantly less than the dispatch instruction set by ISO-NE (failure to move to a Desired Dispatch Point)
- Failure to activate operating reserve
- Failure to start or shut down a generator.

ISO-NE uses all available data to determine if a plant inspection is warranted. If the determination is made that a plant inspection is appropriate, ISO-NE contacts both the plant management and the lead participant to coordinate access to the plant to visually inspect the reported cause of the forced outage.

Upon completion of the plant inspection, further discussion addresses any questionable observations. ISO-NE accesses all data related to the initiation of the plant inspection, all data collected from both plant personnel interviews, plant operating logs, and the visual plant inspection reported to have caused the forced outage. Once the review is completed, a confidential report is generated that summarizes the event. If the plant inspection results in findings that evidence exists of physical withholding of the resource, further contact is made to obtain any additional information that may be appropriate. If all available information indicates that physical withholding has occurred, then sanctions may be imposed as outlined in Appendix B of Market Rule 1.

During the months of March – June 2003 there was one instance in which ISO-NE determined that a plant inspection was warranted as a result of monitoring for the potential physical withholding of a resource. The inspection concluded that no physical withholding occurred as a result of the outage.

7.3. Supply Curves by Hour

Figure 38 shows the Energy Market supply curves for internal New England resources that offered (Economic Maximum Available > 0, i.e., "available") to the market for each hour on June 27, 2003 – the peak demand day for the quarter. The hours shown in the graph were selected to represent the offer patterns for the entire day, and include the peak hour supply offers. The peak demand for the New England system was 24,494 MW during the hour ending 3:00 p.m. The Hub LMP for this hour was $143.20/MWh.

Figure 38 – Supply Offer Curves by Hour, Peak Day

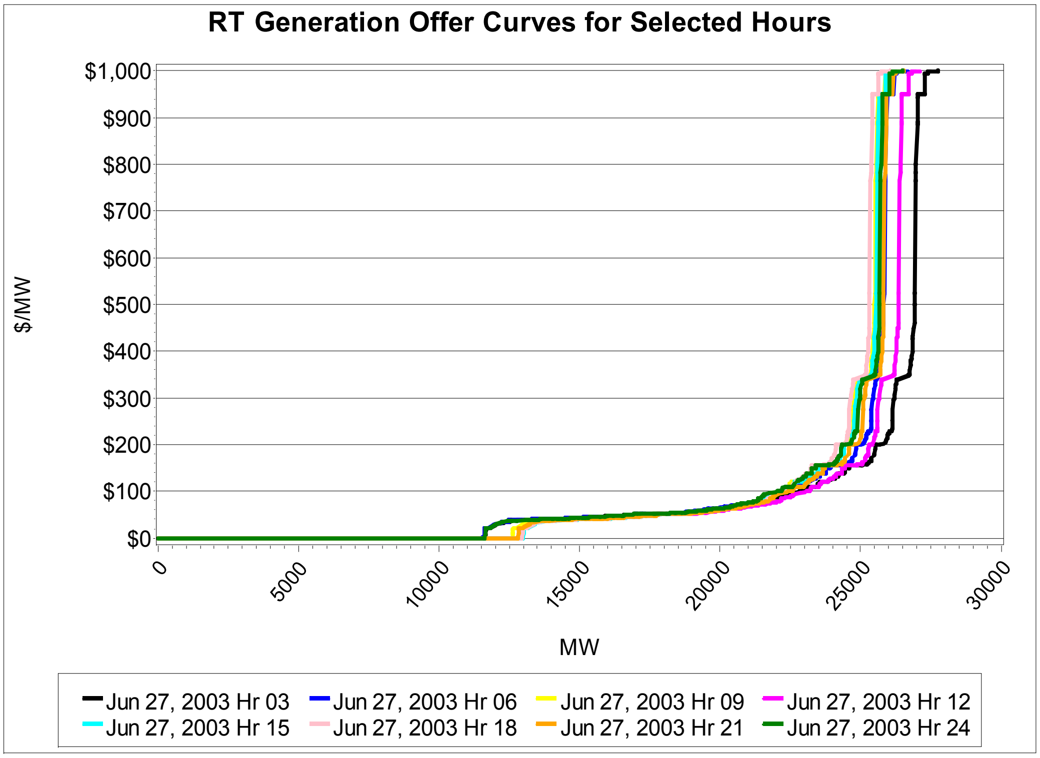


Figure 39 below presents the same data with the y-axis limited to $100 to show greater detail. The shift to the right during the peak hours is caused by more units opting for "must-run" status.

Figure 39 – Supply Offer Curves by Hour <$100, Peak Day

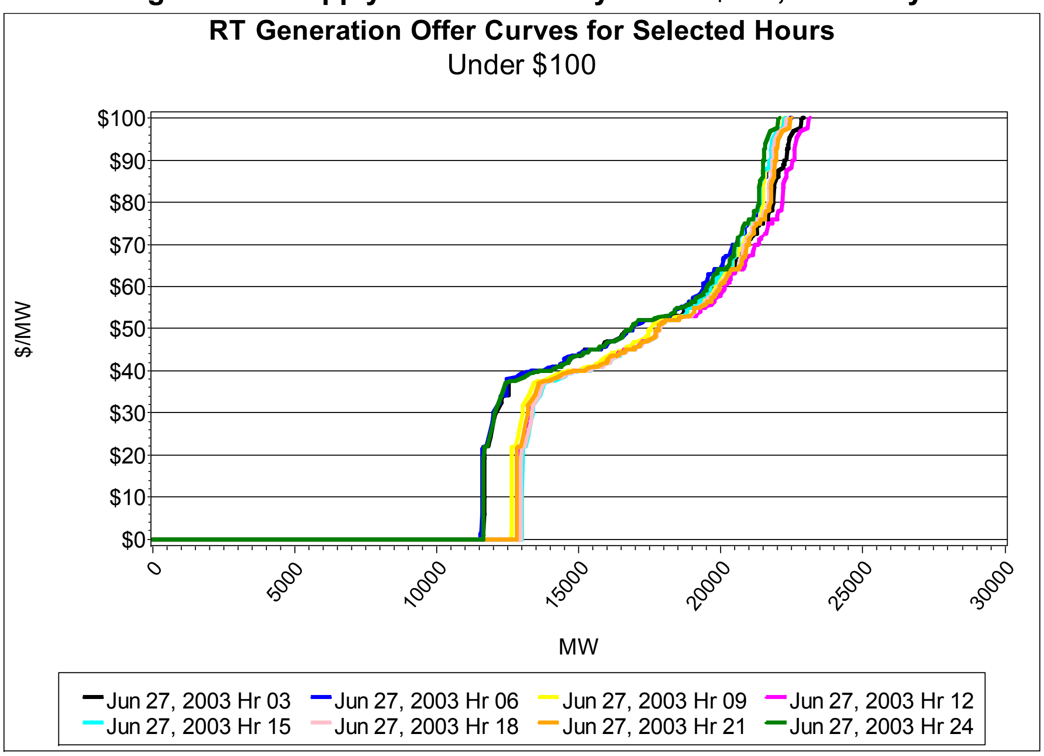
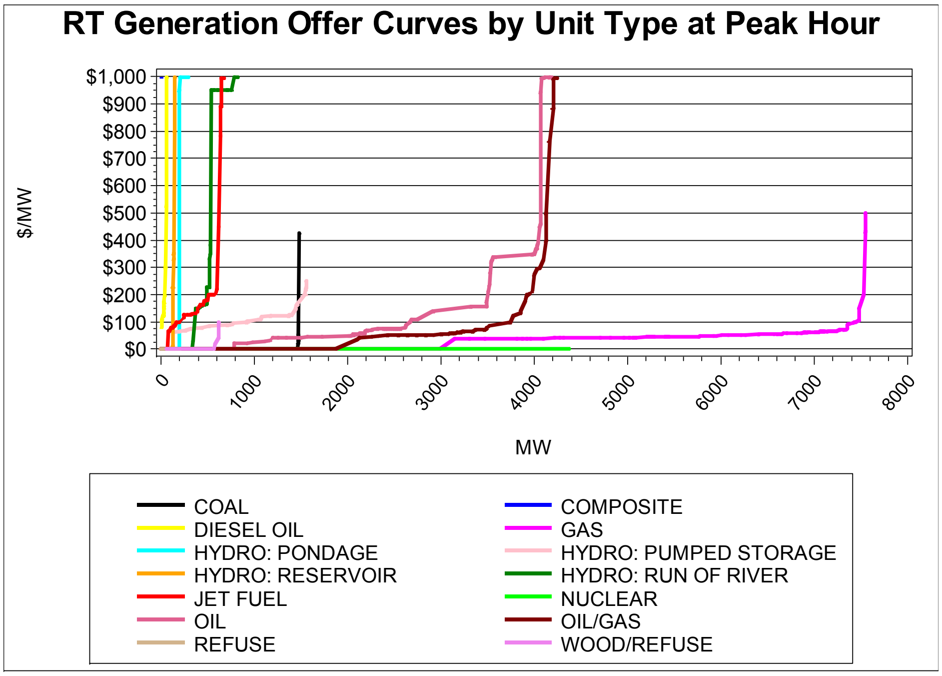


Figure 40 shows the Energy Market supply curves by fuel type for internal New England resources that offered (were available with Economic Maximum > 0) to the market for the peak hour on June 27, 2003. Approximately 7,500 MW of gas-fired capacity was offered into the RT market– about 29% of the total MW offered in this hour – most at less than $100 per MW.

Figure 40 – Generation Offer Curves by Fuel Type on June 27



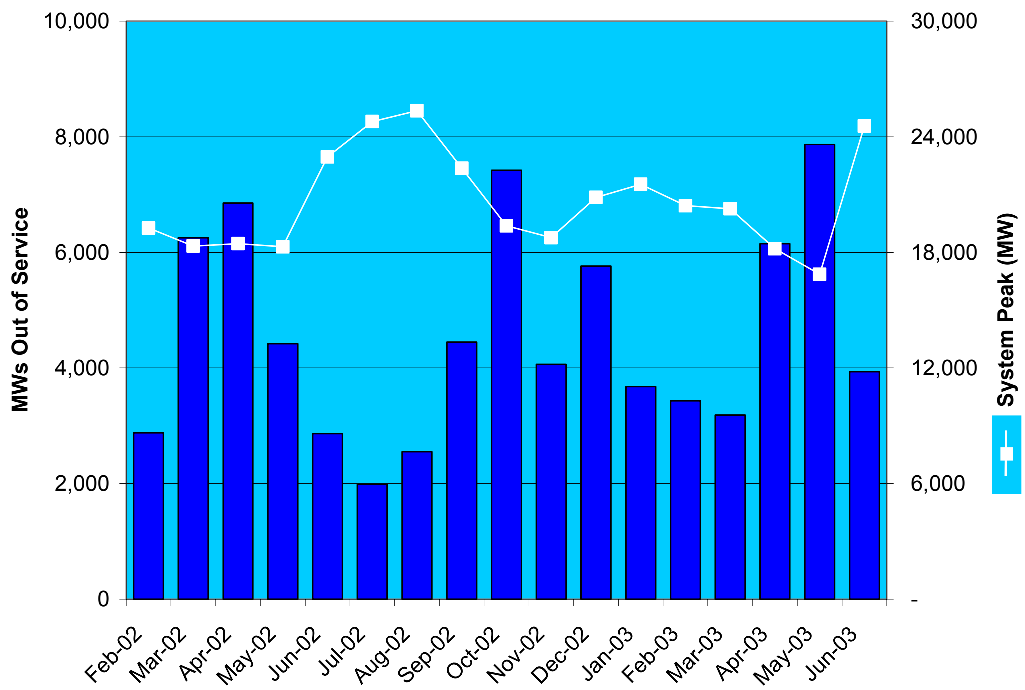
8. Generator Unit Availability

In its continuing effort to monitor and analyze the availability[14] of New England Power Pool's (NEPOOL) generating units, ISO-NE's System Planning department has prepared this section of the quarterly report on unit performance statistics. Historical generator availability is presented to provide an overview of trends in unit performance.

8.1. Availability vs. Demand

Figure 41 shows the 16-month historical monthly peak loads and the corresponding total outages for the period March 2002 through June 2003. The graph indicates that generating unit outages have an inverse relationship with seasonal demand, that is, less outages occur during the summer and winter peak periods.

Figure 41 – Total Peak Day Outages in MW and Monthly Peak Loads



8.2. Overall Availability

Overall unit availability of New England's generators decreased during the quarter when compared to the previous "quarter" (November 2002 through February 2003), as shown in Table 33. This is consistent with the March – June timeframe being the prime season for scheduled generator maintenance.

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[14] 'Availability' and terms used throughout this section are defined in Appendix I.

Table 33 – WEAF by Unit Type, All Units

Weighted Equivalent Availability Factors (%) by Unit Type, All New England Units																
	1995	1996	1997	1998	1999*	2000	2001	2002	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
System Average	79	78	75	78	81	81	87	89	86	91	93	91	82	83	81	90
Fossil Steam	81	81	84	81	79	78	83	85	78	89	94	94	88	80	74	88
Nuclear	63	53	32	53	82	89	92	91	100	92	99	96	87	94	90	98
Jet Engine	88	92	94	93	70	88	95	94	95	97	97	95	93	92	92	98
Combustion Turbine	94	92	96	92	90	83	89	92	96	96	98	96	87	78	91	99
Combined Cycle Total	90	92	92	89	83	80	85	90	82	88	87	80	67	78	79	84
Pre-1999 Combined Cycle	*90*	*92*	*92*	*89*	*91*	*89*	*96*	*92*	*86*	*96*	*95*	*96*	*77*	*75*	*92*	*96*
New (Installed 1999-2002) Combined Cycled	*n/a*	*n/a*	*n/a*	*n/a*	*47*	*67*	*76*	*89*	*79*	*84*	*83*	*73*	*64*	*80*	*75*	*79*
Hydro	83	88	86	86	81	81	96	96	97	97	98	96	95	97	98	97
Pumped Storage	97	94	97	91	90	86	95	87	99	99	98	96	90	85	87	99
Diesel	90	94	90	89	76	88	98	98	94	96	95	94	98	100	99	100

* 1999 represents May-December data

The reader should note that the 2001 - 2003 statistics were computed using a different data source than what was used for the 1995 – 2000 statistics.[15]

Analysis of generator outages from March through June 2003 shows that:

- Generator availability increased in June, coinciding with the start of the summer season.
- The months of March - May experienced the lowest availabilities of the quarter due primarily to a greater amount of scheduled maintenance. A large portion of this scheduled maintenance (approximately 50%) was annual maintenance previously scheduled for this timeframe.

8.3. New Generating Plants

As reported in a June 14, 2001 report prepared for ISO-NE entitled "*Understanding Generator Unit Availability*," certain newer combined cycle units had performed below manufacturers' expectations. Table 34 illustrates this observation by showing the first three years of availability statistics for combined cycle units installed in the NEPOOL Control Area during the period 1999-2003. For the first three years, new combined cycle units' Average Equivalent Availability Factors (EAF) are presented with the technology's Target Unit Availability (TUA).[16].

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[15] The statistics for the years 1995 - April 1999 were calculated from the NEPOOL Automated Billing System (NABS). NABS data is representative of traditional, cost-based system dispatch. The system captured actual run-time MW/hour information and outage information as defined in the billing rules. The data were used primarily by the NEPOOL Settlements Department for payment to the generators. Based on statistical analysis approved by the NEPOOL Power Supply Planning Committee, generators were allotted a certain amount of maintenance outage weeks per year to perform "scheduled maintenance." If an outage ran over this amount, or was out of service any other time, it was considered "unplanned" or "forced." Statistics for May 1999 - 2003 were based upon competitive bid-based dispatch and calculated from a Short Term Outage Database. This database is populated by the ISO-NE Forecast and System Planning Departments based upon information received from generators, and records scheduled and unplanned outages as they occur in real time.

[16] Target Unit Availability (TUA) is the expected availability as defined by Planning Procedure 5-2, Attachment I.

8.3.1. New Combined Cycle Plants

To better understand the "break-in" period of combined cycle plants, additional analysis based on monthly availability was performed. A unit's break-in period is the time required for a new plant to work through any start-up problems associated with a new unit installation. Often, the time spent resolving new unit issues can result in lower availability for a generating unit. The time period required can be several months or several years depending upon the owner, manufacturer, and the unit design. The average EAF statistics of New England new combined cycle facilities is presented in Table 34 below, grouped by the number of months the unit has been available for commercial operation. Table 34 was developed by determining monthly availabilities for each new combined cycle unit installed in New England during the 1999-2003 timeframe. These monthly values were then averaged to produce availability statistics based upon the number of months of service (or equivalent years in service).

Results of this analysis show that second year units have the highest EAF when compared to the first and third year units. As illustrated by the ESOF of first and third year units, this is mostly because units in their first (break-in period) and third (scheduled warranty work) years of operation are performing a large amount of scheduled maintenance – scheduled both short-term and well in advance.

Table 34 – Average Equivalent Availability Factor for New CC Units

New Combined Cycle Units - Average Equivalent Availability Factor[17] By Number of Months In-Service				
Year of Service	**Months**	**EFOR**	**ESOF**	**EAF**
First Year	1-12	12.79	17.79	71.39
Second Year	13-24	4.70	10.44	85.87
Third Year	25-34	1.76	16.43	81.84
TUA		*4.49*	*5.77*	*90.00*

8.4. Historical Monthly Availability

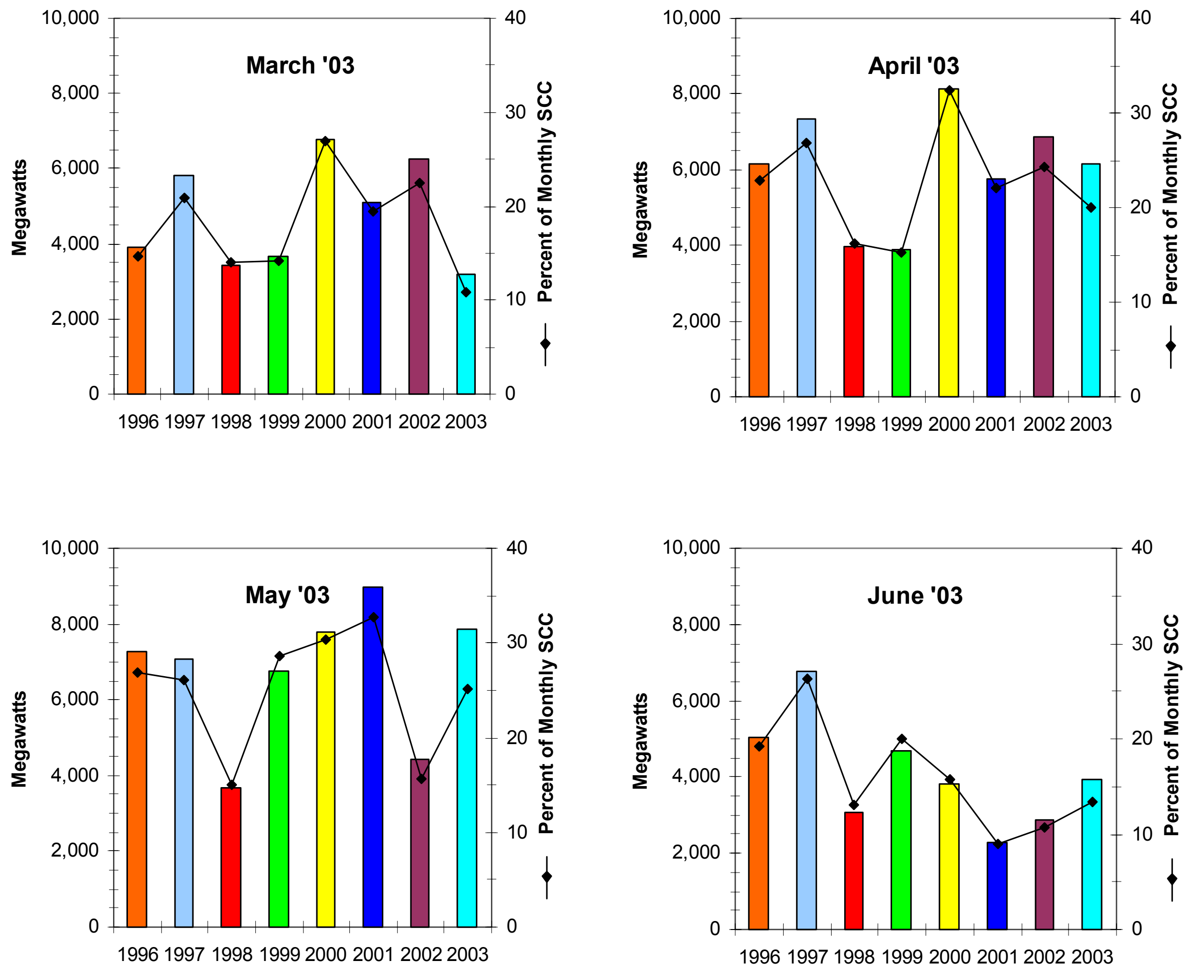
Figure 42 illustrates the total number of megawatts (MW) out-of-service at the time of the monthly peak load for March through June 2003 with a comparison to the same months in previous years. These outages are expressed in aggregate MW as well as a percentage of the total NEPOOL monthly Seasonal Claimed Capability (SCC)[18] for that month. Specifically, Figure 42 shows that the number of MW out-of-service during the day of the monthly peak in March 2003 was less than in previous years for the same month while for the months of April – May 2003, there is no general pattern to the total MW out-of-service at the time of peak but there are also no data outliers. During June, the amount of MW out-of-service has been increasing (both in terms of absolute MW and as a percent of SCC) each year since

[17] Availability Factors are defined in Appendix I attached. Data represents the period August 1999 through June 2003.

[18] The Seasonal Claimed Capability (SCC) reports may be found on the ISO New England Inc. web site at http://www.iso-ne.com/seasonal_claim_capability_report.

2001. ISO-NE has noted this trend and always ensures that the combination of expected forced outages with planned outages will not cause the system operable capacity to drop below levels required to ensure reliability.

Figure 42 – Historical Comparison of Peak Day Outages (MW and Percent of SCC)



8.5. Types of Unit Outages

Figure 43 shows the number of equivalent outage hours, by type of outage, as a percent of total outage hours[19] for the March through June 2003 timeframe.

Outages are categorized into one of 4 different types[20]:

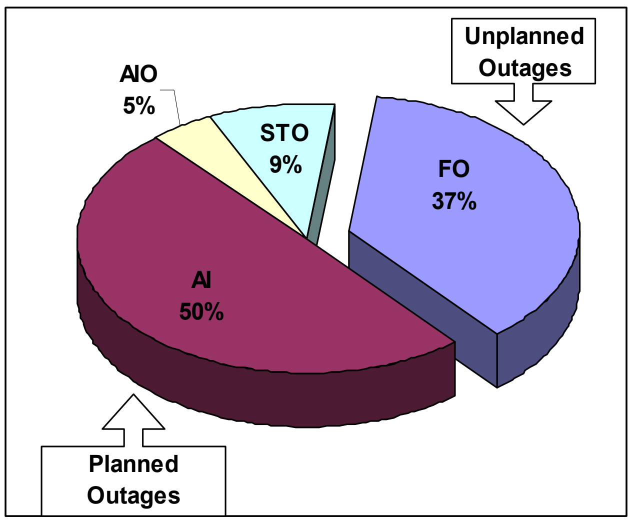
[19] Percentages may not equal 100 due to rounding.

[20] Outage types are defined in Appendix I and are consistent with NEPOOL Operating Procedure No. 5 (OP-5), *Generation Maintenance and Outage Scheduling*.

- AI =Annual Inspection
- AIO=Annual Inspection Over-run
- STO=Short Term Outage
- FO =Forced Outage

All outage categories above are used in determining a generator's availability. Equivalent scheduled outage hours, specifically AI, AIO, and STO, are used to determine the Equivalent Scheduled Outage Factor[21] (ESOF), and FO equivalent outage hours is used to determine the Equivalent Forced Outage Rate (EFOR). Generation out-of-service or reduced as a result of transmission outages is not used in the calculation of the unit WEAF since it is assumed that a generator would be 100% available if the associated transmission element was not out-of-service. During the quarter, approximately 63% of the outage hours were known and scheduled in recognition of reliability requirements of the New England Power Pool, while approximately 37% of the outage hours this quarter were unplanned. Future reports will attempt to track statistic over time, including a historical retrospective.

Figure 43 - Generator Outages by Category March 2003 – June 2003



8.6. Components of Availability: WEFOR and WESOF

In Table 33, the WEAF's of New England unit types were illustrated. The components of those statistics are described below in Table 35. As can be seen from the table, much of the lower WEAF values for this quarter is due to scheduled outages. This is a typical outcome for this time period.

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[21] WEAF, ESOF and EFOR are defined in Appendix I.

Table 35 – Availability Statistics for March – June 2003

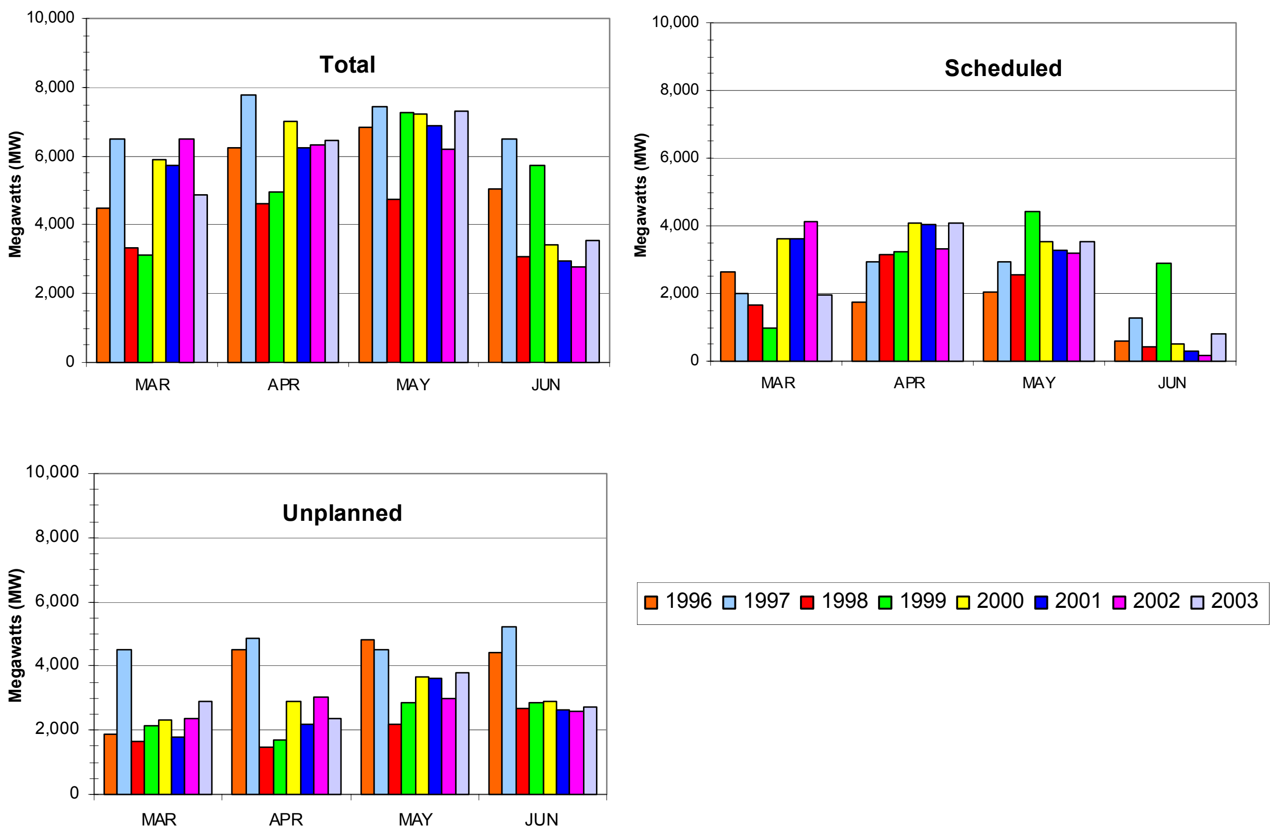
	MW*	% of System	WEFOR (%)	WESOF(%)	WEAF (%)
System	29,059	100	5.02	10.77	84.96
Fossil Steam	10,580	36	5.22	13.89	82.11
Nuclear	4,333	15	3.93	4.16	92.03
Jet Engine	733	3	1.31	5.14	93.67
Combustion Turbine	1,348	5	2.82	8.60	88.60
Combined Cycle Total	8,824	30	7.52	12.90	80.47
Pre-1999 Combined Cycle	*2,253*	*8*	*2.46*	*13.72*	*84.96*
New (installed 1999-2003) Combined Cycle	*6,571*	*23*	*9.25*	*12.62*	*78.92*
Hydro	1,516	5	0.59	2.80	96.77
Pumped Storage	1,643	6	0.94	8.78	90.38
Diesel	83	0	0.53	0.21	99.26

- Per July 1, 2003 Seasonal Claimed Capability Report ratings (all values rounded to nearest MW)

8.7. Scheduled & Unplanned Outages

Figure 44 compares total MW out-of-service on a monthly basis for 1996-2003, and shows the elements of scheduled (AI, AIO, STO) and unplanned (FO) MW out-of-service, respectively. Since the beginning of wholesale electricity markets in 1999, average total weekday outages for June have generally been decreasing. This decline is primarily due to less scheduled outages during this time period when compared to previous years. For the other three months, there has been a somewhat higher level of unplanned outages.

Figure 44 - Average Monthly Megawatts Out-of-Service (Weekdays Only)



9. Administrative Price Corrections

ISO-NE continually monitors the processes that are associated with the calculation of LMPs. In the event of a data input failure, hardware or software failure or outage, program failure or binding constraint errors, corrective actions may be taken to ensure that the resulting LMPs are as accurate as is reasonably obtainable.

Hourly RT LMP values are derived by integrating 12 five-minute interval values. Corrections to as few as one interval within an hour will result in a corrected hourly value. Table 36 below details the type and number of hourly Real-Time LMP corrections that were made during the quarter.

Table 36 – Administrative Price Corrections for the Quarter

Correction Type	March-03	April-03	May-03	June-03	Total
Data Entry Error	0	1	3	8	12
Hardware/Software Unscheduled	3	2	2	1	8
Hardware/Software Scheduled	0	1	2	4	7
Software Error	8	2	9	7	26
Total	11	6	16	20	53

10. FERC Filings and Market Rule Changes

- In March 2003, ISO-NE and NEPOOL made the following filings with the FERC:

  FERC Docket No. ER03-210, NEPOOL Compliance Filing and 96th Agreement: On March 1, 2003, NEPOOL submitted to the FERC a compliance filing to a January 31 Order. The filing (called the 96th Agreement) amends the NEPOOL Tariff in order to clarify that neither Congestion Costs, nor FTRs, will be assigned to the Cross Sound Cable (CSC) as long as it remains non-PTF.

  FERC Docket No. ER03-210, ISO-NE Compliance Filing regarding unscheduled capacity on the Cross-Sound Cable: On March 3, 2003, ISO-NE submitted a compliance filing, the purpose of which was to confirm that existing provisions within the NOATT were in place which would govern the release of unscheduled (or secondary) capacity on the Cross Sound Cable (CSC).

  FERC Docket No. EL03-25-000, NEPOOL Compliance Filing regarding Hydro Quebec Interconnection Capability Credits: On January 31, 2003, the FERC issued an order which directed NEPOOL to establish Hydro Quebec Interconnection Capability Credits ("HQICCs") at a certain MW level for certain months of the 2002/2003 NEPOOL Power Year for the purposes of the NEPOOL ICAP Market. After agreeing on a proper interpretation of the FERC order, NEPOOL made the proper adjustments and filed their compliance on March 3, 2003.

  ISO-NE Compliance Filing on Scarcity Premium Proposal: In a December 20, 2002 order on rehearing of Market Rule 1, the FERC approved the ISO's "Proxy CT Price" mitigation mechanism tied to scarcity pricing, but also directed the ISO to review and comment upon an alternative "Scarcity Premium Proposal" that is intended to encourage capacity investment in areas lacking sufficient supply resources. In its March 20, 2003 compliance filing, ISO-NE concluded that it should retain its focus on using the Proxy CT method while looking forward to a locational ICAP methodology as a long-term solution.

  Docket No.ER02-2330: ISO-NE SMD Status Report Compliance Filing: In a September 20, 2002 Order, the FERC directed ISO-NE to begin filing quarterly status reports regarding the implementation and further development of SMD. On March 20, 2003, ISO-NE submitted the second status update, reporting on various areas of interest, including price formation, seams reduction, and resource adequacy initiatives.

- In April 2003, FERC issued the following orders:

  FERC Docket No. ER03-210: FERC Order accepting amendment to 96th Agreement: On April 9, 2003, FERC accepted filed revisions to the 96th Agreement to the Restated NEPOOL Agreement (RNA). The revisions provide that neither Congestion Costs, nor FTRs, will be assigned to Merchant Transmission Facilities, such as Cross Sound Cable (CSC), as long as such facilities remain non-PTF.

  FERC Docket No. ER03-550-000: FERC Order accepting revisions to Market Rule 1: On April 22, 2003, the FERC approved a joint-submitted proposal that will allow ISO-NE to suspend – in particular situations - a controversial, new approach ("Proxy CT") to pricing power in chronically congested areas. However, this order was subsequently mooted by FERC's April 25, 2003 order in Docket No. ER03-563-000 directing ISO-NE to eliminate the Proxy CT methodology.

FERC Docket No. ER03-563-000: FERC Order regarding RMR contracts and temporary bidding rules: On April 25, 2003, FERC issued this order, which will change the way seldom-run generating units will be compensated in the marketplace. FERCs intention is to revise RMR agreements and allow certain peaking units to recover their fixed and variable cost-of-service through the market by allowing them to raise their bids. These changes are considered temporary, as FERC directs a more permanent solution, such as locational capacity requirements, to be implemented sometime prior to March 1, 2004.

FERC Docket No. EL03-25-001: FERC Order regarding calculation of Hydro Quebec Interconnection Capacity Credits (HQICC): On January 31, 2003, FERC directed NEPOOL to establish Hydro Quebec Interconnection Capability Credits ("HQICCs") at a certain MW level for certain months of the 2002/2003 NEPOOL Power Year for the purposes of the NEPOOL ICAP Market. While NEPOOL complied with this order, requests for clarification and rehearing were made. On April 30th, FERC restated the requirement for setting HQICC levels and clarified that that the levels should not be changed retroactively.

❖ In May 2003, ISO-NE and NEPOOL made the following filings with the FERC:

FERC Docket No. ER03-854: On May 15, 2003, ISO-NE filed with FERC its "Scarcity Pricing Proposal." The proposal would, during times of Operating Reserve deficiency, set affected RT nodal prices to $1000/MWh and provide opportunity cost payments to generators. ISO-NE believes this will address an important flaw in the current market design and ensure that energy prices are set at economically efficient levels during those periods. The requested effective date is July 1, 2003.

FERC Docket No. ER03-849: On May 16, 2003, ISO-NE filed for acceptance with FERC amendments to NEPOOL Market Rule 1 affecting rules for general mitigation. The proposal implements mitigation measures for units in a supplier's bid portfolio where the supplier has a system-wide market power in a specific supply hour. The proposal is intended to prevent prices from being inefficiently set during certain high demand periods.

FERC Docket No. ER03-563: On April 25, 2003, FERC issued an order directing ISO-NE to file a revision to Market Rule 1 that removes the provisions establishing a generic safe-harbor reference level for generating units located in chronically congested areas and instead establishes unit-specific levels for units that have low capacity factors. On May 30, 2003, ISO-NE made a compliance filing for requesting an implementation date of June 1, 2003.

❖ In May, FERC issued the following orders:

FERC Docket No. ER03-421: On May 16, 2003, FERC issued an order regarding RMR agreements, reaffirming their intention for the replacement of generic safe-harbor reference levels with unit specific levels for certain RMR units in chronically congested areas. As previously mentioned, ISO-NE made a compliance filing relating to this subject on May 30, 2003.

❖ In June 2003, ISO-NE and NEPOOL made the following filings with the FERC:

FERC Docket No. ER03-910-000: Revisions to NEPOOL Market Rule 1 and its Appendices. On June 2, 2003, NEPOOL filed with FERC broadly supported changes to NEPOOL Market Rule 1 and its appendices intended to improve the clarity of documentation of Standard Market Design relating to: Operating Reserve Credits, treatment of Excepted Transactions in the ARR process, Qualified Upgrade Award determination, and other miscellaneous changes. On June 5, 2003 NEPOOL filed for acceptance of these changes. The changes were requested to have an effective date of August 1, 2003.

FERC Docket No. EL-00-62-055: Compliance Report on Performance Based Standards. On June 18, 2003, in compliance with a December 20, 2002 order, ISO-NE submitted to the FERC an informational filing which detailed newly developed metering and curtailment technology guidelines intended to be more flexible and encourage market growth for demand response resources.

Docket No. ER02-2330-014: ISO-NE Quarterly SMD Compliance Filing. On June 18, 2003, ISO-NE complied with a September 20, 2003 FERC order by submitting their third quarterly status update concerning the implementation of SMD. The updates involve several initiatives including: nodal pricing, QUA award determination, price-setting eligibility, regional and locational resource adequacy, resource adequacy, partial de-listing of ICAP resources, "mileage" payments for Regulation service, Transmission upgrade cost allocation, and Operating Reserve payment for partially self-scheduled resources.

Docket No.ER03-345-001: ISO-NE Load Response Program Report Compliance Filing. On June 30, 2003, ISO-NE complied with a February 25, 2003 FERC order by submitting the first biannual status report regarding Load Response programs in New England. The report includes information regarding customer enrollment, potential load reduction, actual Load Response event information, and the effects of demand response programs on wholesale prices.

- In June 2003, FERC issued the following orders:

FERC Docket No. ER02-2330-004: On June 6, 2003, FERC issued an order to make clarifications and respond to compliance filings related to Standard Market Design. In the order FERC upheld their support for their recent approval of safe-harbor bidding in congested load pockets for seldom-run peaking units as an interim mechanism until location adequacy requirements can be implemented. Other aspects of SMD addressed in the order involved Market Monitoring, RMR contracts, demand response, and ARR and Operating Reserve allocation formulas.

FERC Docket No. EL03-11-001: On June 6, 2003, FERC issued an order delineating the circumstances under which market Participants could request (retroactively or going forward) from the ISO a reassessment of their responsibilities in the ICAP market. ISO-NE and NEPOOL were directed to submit the appropriate market rule changes in a compliance filing to support this ruling.

11. Appendix 1 – Glossary of Unit Availability Terms

Term	*Acronym*	*Definition*
Annual Inspection	AI	Defined by NEPOOL Operating Procedure No. 5 (OP-5) as an outage or de-rate scheduled more than 2 weeks in advance and performed on a periodic basis.
Annual Inspection Over-run	AIO	An extension of an AI outage due to unforeseen circumstances discovered during the maintenance period.
Forced Outage	FO	Unplanned Outage. Defined by OP-5 as an unplanned/unexpected outage or de-rate that cannot be delayed and interrupts operation of the machine.
Equivalent Availability Factor	EAF	$(1-\text{EFOR})(1-\text{ESOF})\times 100$
Equivalent Available Hours	EAH	Total number of hours a unit is available for operation.
Equivalent Forced Outage Hours	EFOH	$\sum \frac{(\text{MW Reduction})(\text{\# Hours Unplanned Outage})}{\text{SCC}}$
Equivalent Forced Outage Rate	EFOR	$\left(\frac{\sum \text{EFOH}}{\text{SH}-\sum \text{ESOH}}\right)\times 100$
Equivalent Scheduled Outage Factor	ESOF	$\left(\frac{\sum \text{ESOH}}{\text{SH}-\sum \text{EFOH}}\right)\times 100$
Equivalent Scheduled Outage Hours	ESOH	$\sum \frac{(\text{MW Reduction})(\text{\# Hours Planned Outage})}{\text{SCC}}$
Forced Outage Hours	FOH	Total number of hours a unit was forced out of service
Period Hours	PH	Number of hours a unit was in the active state; a unit generally enters the active state on its commercial date.
Scheduled Outages		$\text{STO}+\text{AI}+\text{AIO}$
Reserve Shutdown Hours	RSH	Number of hours a unit was available for operation but not electrically connected to the transmission grid.
Service Hours	SH	The number of clock hours in a study period. (2,928 hours was the total number used in the study period of March 2003 through June 2003.)

Term	***Acronym***	***Definition***
Scheduled Outage Hours	SOH	Total number of hours a unit was out due to a Scheduled event.
Short Term Outage	STO	Defined by OP-5 as an outage or de-rate scheduled less than 2 weeks in advance and usually less than 5 days in duration.
Transmission Outage Limitation	TOL	An outage or de-rate of a generator due to constraints in an area of the transmission system.
Weighted Equivalent Availability Factor	WEAF	$(1-\text{WEFOR})(1-\text{WESOF})\times 100$