Monthly Market Operations Report
October 2012

ISO New England Inc.
Market Analysis and Settlements
November 13, 2012

1. Introduction

1.1 About ISO New England

Created in 1997, ISO New England Inc. (the ISO) is the not-for-profit regional transmission organization (RTO) responsible for the day-to-day reliable operation of New England's bulk power generation and transmission system, oversight and administration of the region's wholesale electricity markets, and management of a comprehensive regional bulk power system planning process.

1.2 Market Reporting

The ISO's FERC Electric Tariff No. 3, Section III – Market Rule 1 – Standard Market Design, Appendix A – Market Monitoring, Reporting and Market Power Mitigation Section III.A.11.2.1 requires the ISO to publish a monthly report, "which will be available to the public...containing an overview of the market's performance in the most recent period."

The ISO produces many reports that summarize the operations of New England's wholesale electricity markets. The weekly report provides summaries of key market activities for the trading week encompassing Monday-Sunday. This report, generally posted on Wednesdays, can be found on the ISO's web site here.

Monthly summaries of certain wholesale market concepts are reported monthly by the ISO's Chief Operating Officer at the NEPOOL Participants Committee Meeting. These summaries are posted on the ISO's web site here, under the link entitled "Materials."

Additionally, in compliance with federal requirements, the ISO issues quarterly reports of key statistics for the region's wholesale electric power markets. These reports can be found on the ISO's web site here.

1.3 About This Report

This report summarizes aspects of New England's wholesale electricity markets that are generally not discussed in the first two reports noted above. There are many interrelationships between the various markets that the ISO administers – each of the concepts presented in this report may interact with others, and second order effects cannot be included here. Additional information can be found on the ISO's web site here.

2. Table of Contents

3. Monthly Summary

Day-ahead and real-time LMPs at the New England Hub averaged $35.27/MWh and $34.65/MWh, respectively, during October 2012. Day-ahead and real-time prices at the Hub and in the Load Zones averaged 2-14% higher than September 2012 averages. In the aggregate, October 2012 day-ahead and real-time LMPs were approximately 13% lower during October 2012 than in October 2011. Average natural gas prices were about 7% below the prior year's average prices, while residual fuel prices were up 4% over a year ago.

Overall, the average of the hourly real-time LMPs at the Hub and in the Load Zones ranged between 4.2% lower than day-ahead in the Rhode Island (RI) Load Zone to 1.8% lower than its day-ahead counterpart in the Hub Load Zone. In the Day-Ahead Market, Load Zone average LMPs ranged between 1.7% lower than the Hub average LMPs in the Maine (ME) Load Zone to 2.9% higher than the Hub in the Vermont (VT) Load Zone. Results were similar in the Real-Time Market, with average LMPs ranging from 2.2% lower than the Hub average LMPs in the ME Load Zone to 1.9% higher than the Hub in the VT Load Zone. Price differentials between on-peak and off-peak hours at the Hub and in the Load Zones ranged between 19% and 34% in both the Day-Ahead and Real-Time Markets.

The New England Control Area was a net importer of electricity in the Real-Time Market during October. In the Day-Ahead Energy Market, there were approximately 400,000 MWh of total exports and 1,485,000 MWh of imports, yielding a net import of approximately 1,085,000 MWh. In the Real-Time Energy Market, there were approximately 505,000 MWh of total exports and 1,607,000 MWh of imports, yielding a net import of approximately 1,103,000 MWh. This was about 169,000 MW lower than a year ago.

The Monthly FTR Auction (October 2012) had 39 participants and the awarded value of FTRs in the auction totaled $845,000 . This represented an increase of $201,000 over the previous month and an addition of about $330,000 over the prior year's monthly FTR auction. The allocation of FTR Auction Revenue for October 2012 resulted in $1.6 million awarded to eligible entities, with $78,000 allocated to Incremental Auction Revenue Rights (IARR). (Starting January 2012, 'Qualified Upgrade Awards' have been converted to IARR.).

The Marginal Loss Revenue Fund totaled $5.1 million for October, up $500,000 from its September 2012 total.

Total Forward Reserve Credits to eligible assets of $511,000 were reduced by $70,000 in Failure to Reserve Penalties and $0 in Failure to Activate Penalties during October 2012. The net Forward Reserve Payment of $441,000 represented 79% of the maximum possible payment of $558,000. Real-Time Reserve Prices occurred in 58 separate hours during the month, and those yielded real-time payments to designated assets of $1.1 million. These payments were reduced by Forward Reserve Energy Obligation Charges totaling $241,000 yielding a net compensation of $833,000 during the month.

Regulation Market Payments totaled $788,000 during the month, an increase of $30,000 over the September 2012 value of $758,000.

For the month of October 2012, Forward Capacity payments were made to a total of 32,983 MW of capacity and totaled $89.5 million.

The Transitional Demand Response program is the method through which demand assets can participate in the Energy Market. Payments during October 2012 totaled $125,000 for interruptions associated with Day Ahead, $38,000 for interruptions associated with the Real Time, and $0 associated with FCM Audit. Total Transitional Demand Response payments for the month, $163,000, were down approximately $3,000 from their September levels.

4. Locational Marginal Prices (LMPs)

Under Standard Market Design (SMD), the LMP is the cost of supplying an increment of load at a particular location. LMPs are calculated for each Internal and External Node as well as the eight Load Zones and the internal Hub in both the Day-Ahead and Real-Time 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 MW of energy to the distributed market reference bus. In any hour, the energy component is the same for all locations, while the congestion and marginal loss components vary among locations. If there were no congestion and losses, LMPs would be the same for all locations. Although the three components of the LMP are separated in some stages of the accounting process, the cost of energy at a location is the total LMP.

The following tables summarize Hub, zonal, and external node LMPs during the month on an overall, on-peak, and off-peak basis. On-peak hours are weekdays between 7:00 a.m. and 11:00 p.m. Off-peak hours are weekdays between 11:00 p.m. and 7:00 a.m., Saturdays, Sundays, and North American Electric Reliability Council (NERC) holidays.

4.1 LMP Summary Statistics

The following tables show summary statistics for LMPs for the Hub, eight internal Load Zones, and five external nodes for both the Day-Ahead and Real-Time Markets:

4.1.1 All Hours, October 2012

Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$35.27	$34.65	$15.11	$0.00	$63.24	$243.49	85%	87%	98.2%	$7.37	$14.52	1.97
ME	$34.68	$33.88	$14.84	$0.00	$62.49	$235.76	84%	85%	97.7%	$7.07	$13.56	1.92
NH	$35.61	$34.83	$15.18	$0.00	$64.07	$243.54	86%	88%	97.8%	$7.45	$14.58	1.96
VT	$36.29	$35.30	$15.21	$0.00	$65.49	$247.09	88%	89%	97.3%	$7.79	$14.78	1.90
CT	$35.77	$35.03	$15.03	$0.00	$64.86	$242.78	86%	88%	97.9%	$7.78	$14.71	1.89
RI	$35.72	$34.23	$15.13	$0.00	$78.25	$242.71	86%	86%	95.8%	$7.66	$14.29	1.87
SEMA	$35.27	$34.54	$15.18	$0.00	$63.21	$246.26	85%	87%	97.9%	$7.27	$14.50	1.99
WCMA	$35.73	$34.93	$15.21	$0.00	$63.87	$245.31	86%	88%	97.8%	$7.52	$14.65	1.95
NEMA	$35.61	$34.80	$15.20	$0.00	$63.42	$244.57	86%	88%	97.7%	$7.54	$14.67	1.95
NB Ext	$33.47	$32.72	$14.66	$0.00	$60.73	$225.55	81%	83%	98%	$6.73	$12.69	1.89
NYN Ext	$35.73	$34.81	$15.07	$0.00	$64.24	$244.22	86%	88%	97%	$7.66	$14.57	1.90
HQ Ext	$34.40	$33.98	$15.00	$0.00	$61.78	$238.72	83%	86%	99%	$7.04	$14.26	2.03
HG Ext	$33.70	$35.28	$14.72	$0.00	$67.01	$250.70	81%	89%	105%	$7.01	$15.00	2.14
CSC Ext	$35.85	$35.37	$14.94	$0.00	$64.95	$244.70	87%	89%	99%	$7.91	$14.86	1.88
NNC Ext	$35.97	$35.25	$15.08	$0.00	$65.29	$243.80	87%	89%	98%	$7.83	$14.78	1.89

4.1.2 On-Peak Hours, October 2012

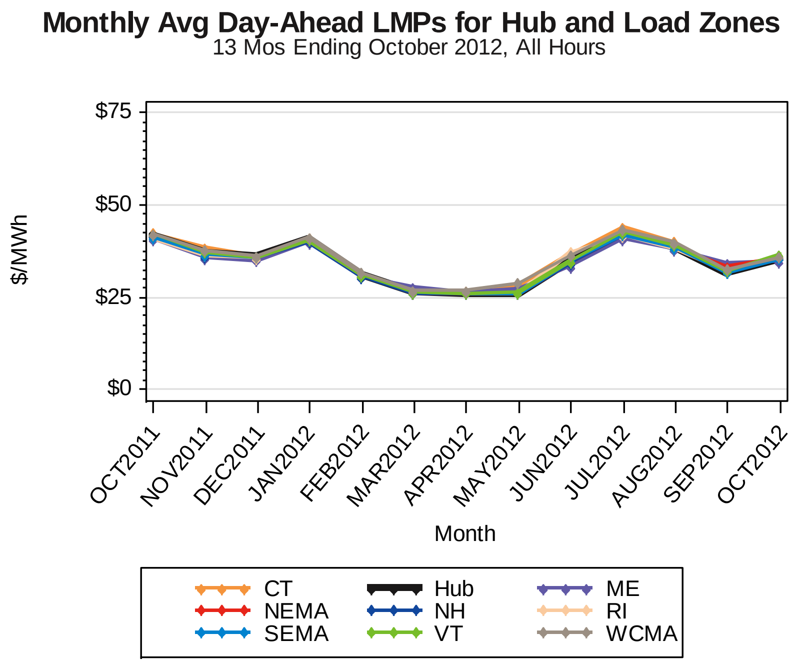
Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$38.81	$39.58	$26.55	$0.00	$63.24	$243.49	84%	88%	102%	$6.09	$17.27	2.84
ME	$38.10	$38.56	$26.93	$0.00	$62.49	$235.76	82%	86%	101%	$5.73	$15.76	2.75
NH	$39.28	$39.82	$27.04	$0.00	$64.07	$243.54	85%	89%	101%	$6.15	$17.28	2.81
VT	$40.19	$40.42	$26.89	$0.00	$65.49	$247.09	87%	90%	101%	$6.39	$17.51	2.74
CT	$39.68	$40.19	$26.56	$0.00	$64.86	$242.78	86%	90%	101%	$6.38	$17.38	2.72
RI	$38.80	$38.99	$26.23	$0.00	$62.12	$242.71	84%	87%	100%	$5.98	$17.04	2.85
SEMA	$38.77	$39.45	$26.38	$0.00	$63.21	$246.26	84%	88%	102%	$5.97	$17.24	2.89
WCMA	$39.45	$39.92	$26.86	$0.00	$63.87	$245.31	85%	89%	101%	$6.18	$17.42	2.82
NEMA	$38.94	$39.64	$26.64	$0.00	$63.42	$244.57	84%	88%	102%	$6.11	$17.33	2.84
NB Ext	$36.64	$37.06	$26.11	$0.00	$60.73	$225.55	79%	83%	101%	$5.47	$14.55	2.66
NYN Ext	$39.59	$39.89	$26.66	$0.00	$64.24	$244.22	85%	89%	101%	$6.28	$17.27	2.75
HQ Ext	$37.76	$38.76	$26.02	$0.00	$61.78	$238.72	82%	87%	103%	$5.79	$16.99	2.93
HG Ext	$37.02	$40.31	$24.96	$0.00	$67.01	$250.70	80%	90%	109%	$5.82	$17.86	3.07
CSC Ext	$39.78	$40.56	$26.44	$0.00	$64.95	$244.70	86%	91%	102%	$6.57	$17.57	2.68
NNC Ext	$39.93	$40.46	$26.89	$0.00	$65.29	$243.80	86%	90%	101%	$6.43	$17.45	2.71

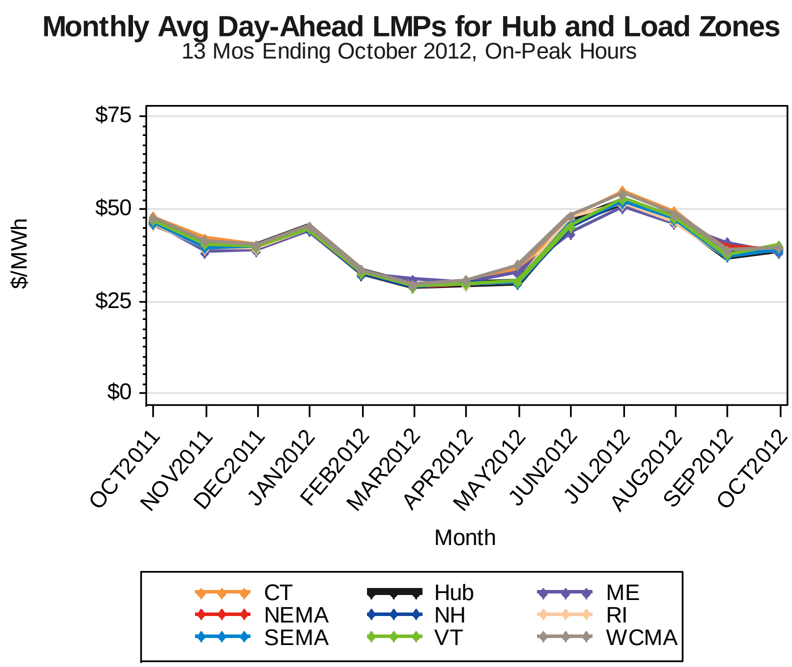
4.1.3 Off-Peak Hours, October 2012

Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$31.81	$29.83	$15.11	$0.00	$57.71	$73.88	85%	84%	94%	$6.84	$8.88	1.30
ME	$31.33	$29.30	$14.84	$0.00	$56.05	$72.85	84%	83%	94%	$6.65	$8.87	1.33
NH	$32.02	$29.95	$15.18	$0.00	$57.60	$74.45	86%	85%	94%	$6.84	$8.96	1.31
VT	$32.47	$30.28	$15.21	$0.00	$59.12	$75.32	87%	85%	93%	$7.11	$9.04	1.27
CT	$31.94	$29.99	$15.03	$0.00	$58.58	$74.84	85%	85%	94%	$7.09	$9.03	1.27
RI	$32.70	$29.56	$15.13	$0.00	$78.25	$73.08	87%	83%	90%	$7.93	$8.76	1.10
SEMA	$31.84	$29.74	$15.18	$0.00	$57.70	$73.34	85%	84%	93%	$6.78	$8.89	1.31
WCMA	$32.10	$30.05	$15.21	$0.00	$58.01	$74.44	86%	85%	94%	$6.91	$8.93	1.29
NEMA	$32.35	$30.05	$15.20	$0.00	$57.70	$82.03	86%	85%	93%	$7.39	$9.33	1.26
NB Ext	$30.37	$28.48	$14.66	$0.00	$54.56	$70.32	81%	80%	94%	$6.40	$8.67	1.36
NYN Ext	$31.95	$29.84	$15.07	$0.00	$58.03	$74.10	85%	84%	93%	$6.99	$8.86	1.27
HQ Ext	$31.12	$29.30	$15.00	$0.00	$56.15	$72.40	83%	83%	94%	$6.59	$8.72	1.32
HG Ext	$30.45	$30.35	$14.72	$0.00	$55.00	$77.79	81%	86%	100%	$6.53	$9.19	1.41
CSC Ext	$32.00	$30.29	$14.94	$0.00	$58.61	$75.74	86%	86%	95%	$7.18	$9.12	1.27
NNC Ext	$32.10	$30.15	$15.08	$0.00	$58.66	$75.11	86%	85%	94%	$7.10	$9.05	1.27

4.2 LMP Graphs, Day-Ahead Market, 13 Months Ending October 2012

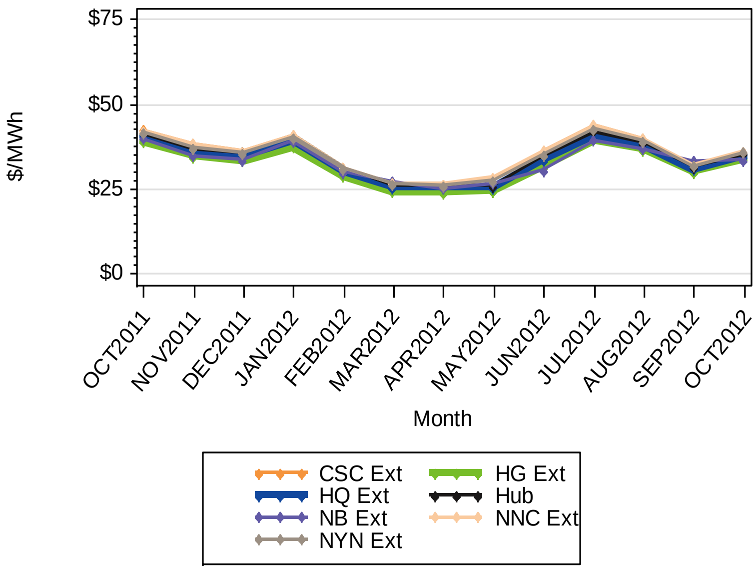
The following four graphs show the 13 month history of average hourly Day-Ahead LMPs for the Hub, Load Zones, and External Nodes on an overall and on-peak basis.





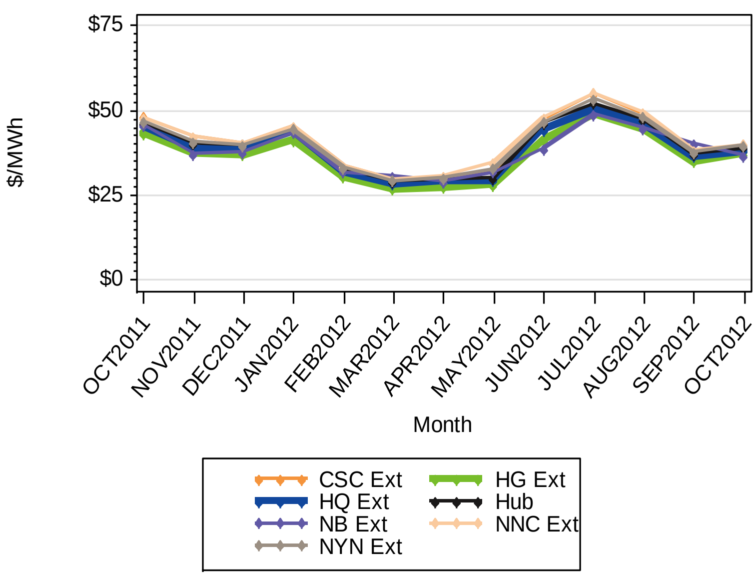
Monthly Avg Day-Ahead LMPs for Hub and External Nodes

13 Mos Ending October 2012, All Hours



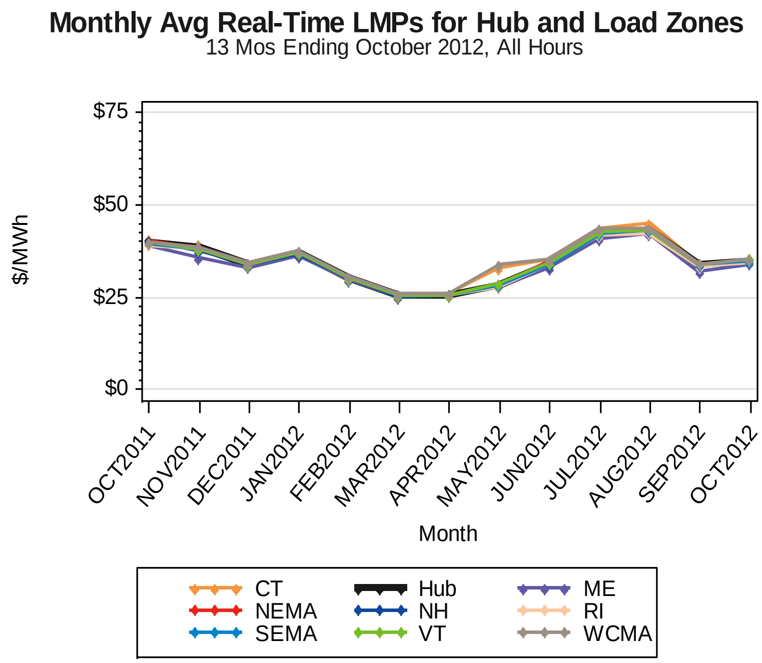
Monthly Avg Day-Ahead LMPs for Hub and External Nodes

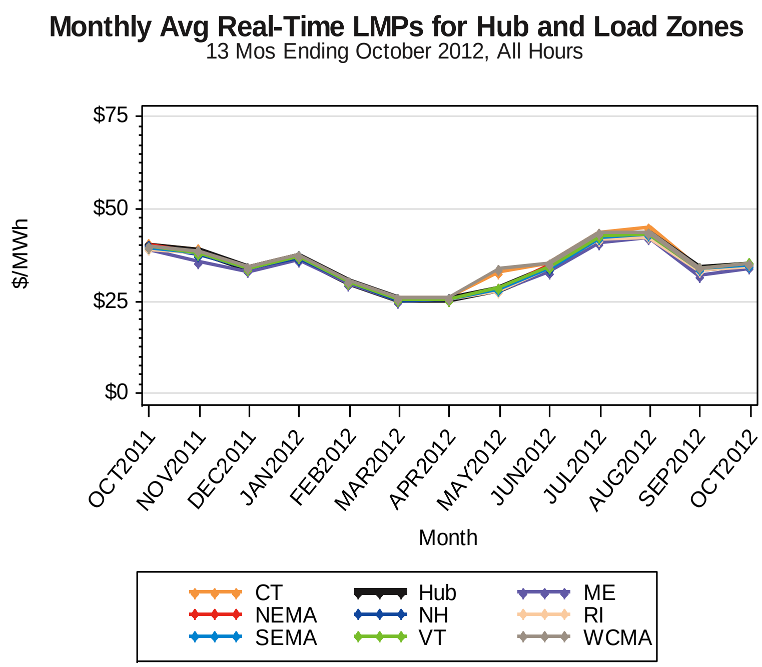
13 Mos Ending October 2012, On-Peak Hours

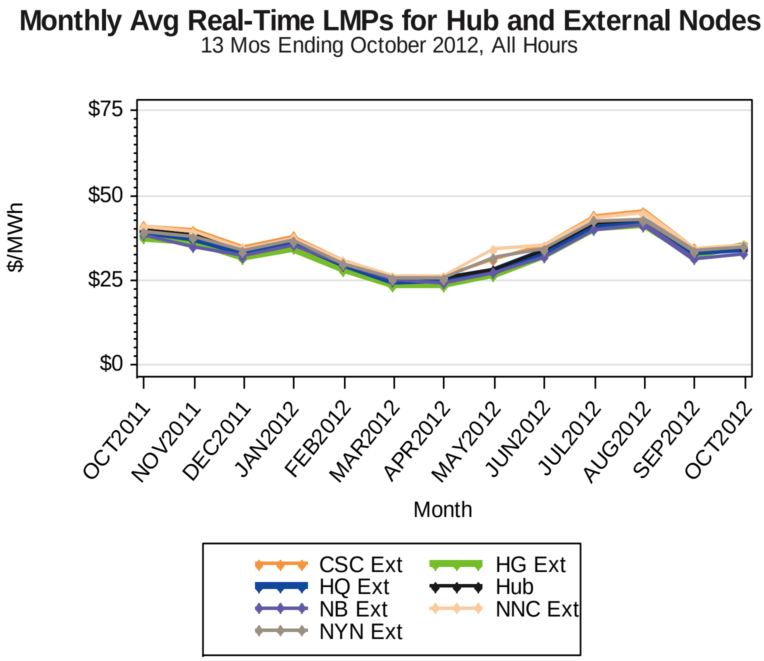


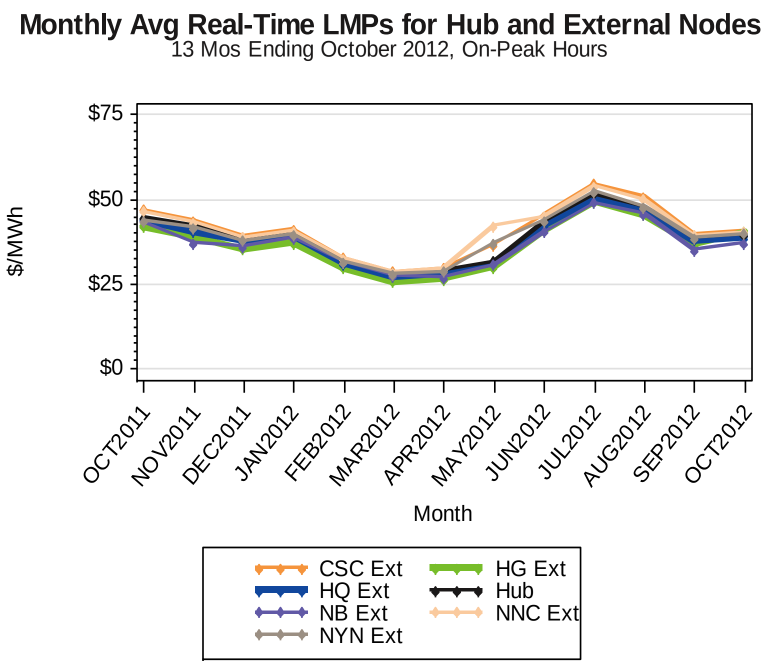
4.3 LMP Graphs, Real-Time Market, 13 Months Ending October 2012

The following four graphs show the 13 month history of average hourly Real-Time LMPs for the Hub, Load Zones, and External Nodes on an overall and on-peak basis.









4.4 For More Information

The ISO provides a discussion of LMP results on a weekly basis in its Weekly Market Performance Report, located here.

The ISO also provides a discussion of LMP results on an annual basis in its Annual Market Performance Reports, located here.

Downloadable Hub and Load Zone weekly and monthly LMP indices are located here.http://www.iso-ne.com/markets/mkt_anlys_rpts/lmp_indices/index.html

Customizable downloads of Day-Ahead and Real-Time Hourly LMPs can be performed here.

Current Day-Ahead and Real-Time LMPs for the Hub and Load Zones can be monitored here.

A discussion of the calculation of LMPs can be found in the ISO's Market Rule 1 located here.

5. Imports and Exports

Market Participants can submit hourly Fixed External Transaction quantities for which they commit to import at Day-Ahead LMPs for delivery in the next Operating Day. They can also submit hourly Fixed External Transaction quantities for which they commit to import at Real-Time LMPs for physical delivery within the Operating Day. There are also several types of price-dependent transactions that can be submitted.

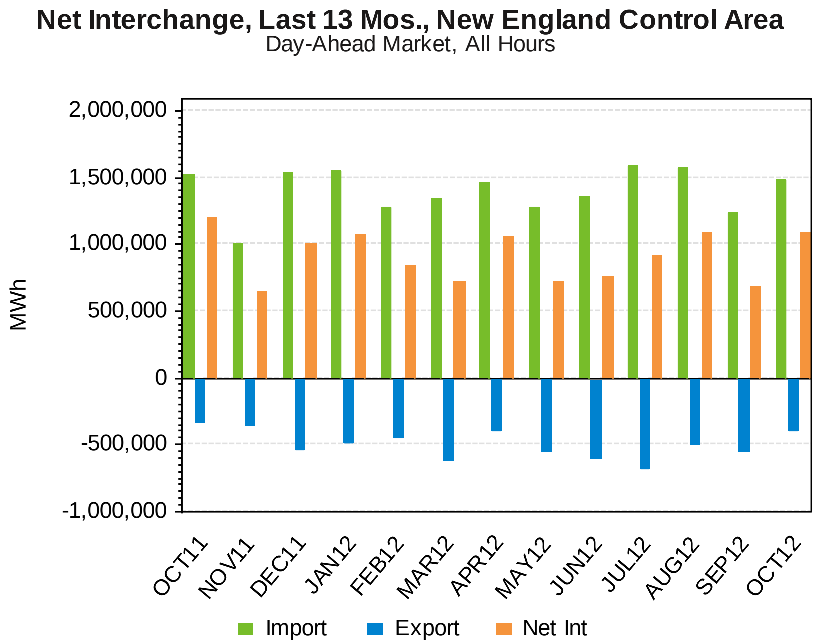
5.1 Net Interchange Summary, October 2012

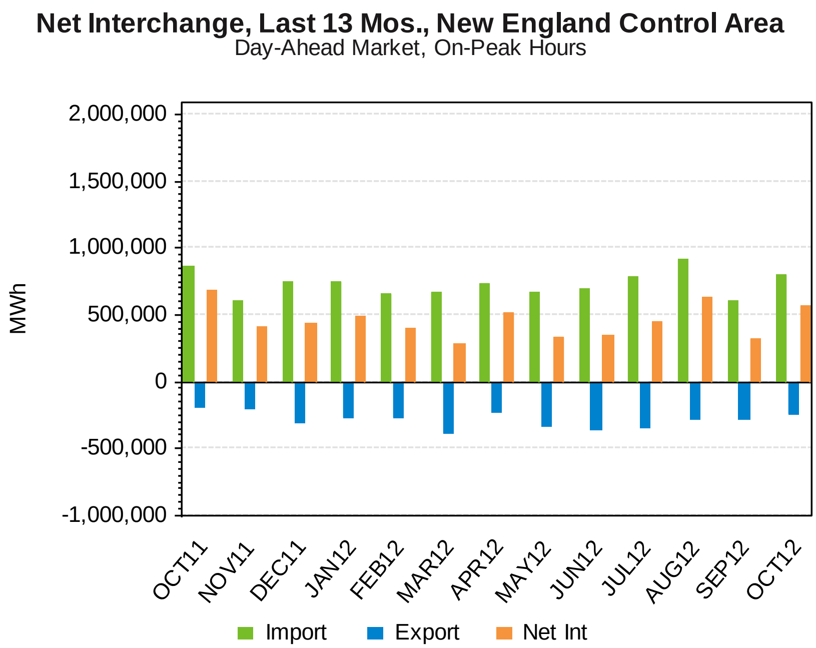
The following tables show summary statistics for imports and exports on the six external interfaces for both the Day-Ahead and Real-Time Markets:

5.1.1 Day-Ahead and Real-Time Market Summary by Interface

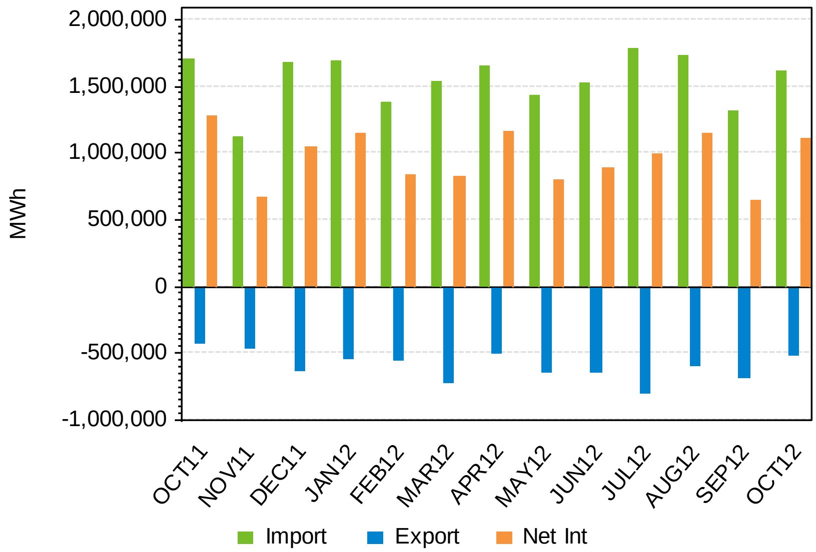
On/Off Peak	Interface	DA Total Exports (MWh)	DA Total Imports (MWh)	DA Net Int (MWh)	RT Total Exports (MWh)	RT Total Imports (MWh)	RT Net Int (MWh)
All Hours	NNC	-69,323	1	-69,322	-75,036	1,058	-73,978
	NY-CSC	-169,137	0	-169,137	-163,783	0	-163,783
	HQ HG	0	24,420	24,420	0	24,861	24,861
	HQ I/II	0	1,076,988	1,076,988	0	1,074,885	1,074,885
	NY-N AC	-141,882	189,526	47,644	-199,192	291,361	92,169
	NB	-19,387	193,685	174,298	-66,552	215,307	148,755
Total	**All Hours**	**-399,729**	**1,484,619**	**1,084,890**	**-504,563**	**1,607,472**	**1,102,909**
Off-Peak	NNC	-34,150	1	-34,149	-38,265	1,030	-37,235
	NY-CSC	-85,148	0	-85,148	-84,068	0	-84,068
	HQ HG	0	6,980	6,980	0	7,421	7,421
	HQ I/II	0	509,662	509,662	0	525,196	525,196
	NY-N AC	-41,541	71,581	30,040	-53,821	122,321	68,500
	NB	-5,601	94,262	88,661	-28,065	105,893	77,828
Total	Off-Peak	-166,440	682,485	516,045	-204,219	761,861	557,642
On-Peak	NNC	-35,172	0	-35,172	-36,771	28	-36,743
	NY-CSC	-83,989	0	-83,989	-79,715	0	-79,715
	HQ HG	0	17,440	17,440	0	17,440	17,440
	HQ I/II	0	567,326	567,326	0	549,689	549,689
	NY-N AC	-100,342	117,945	17,603	-145,371	169,040	23,669
	NB	-13,786	99,423	85,637	-38,487	109,414	70,927
Total	On-Peak	-233,289	802,134	568,845	-300,344	845,611	545,267

5.2 Day-Ahead and Real-Time Net Interchange Summary, Last 13 Months

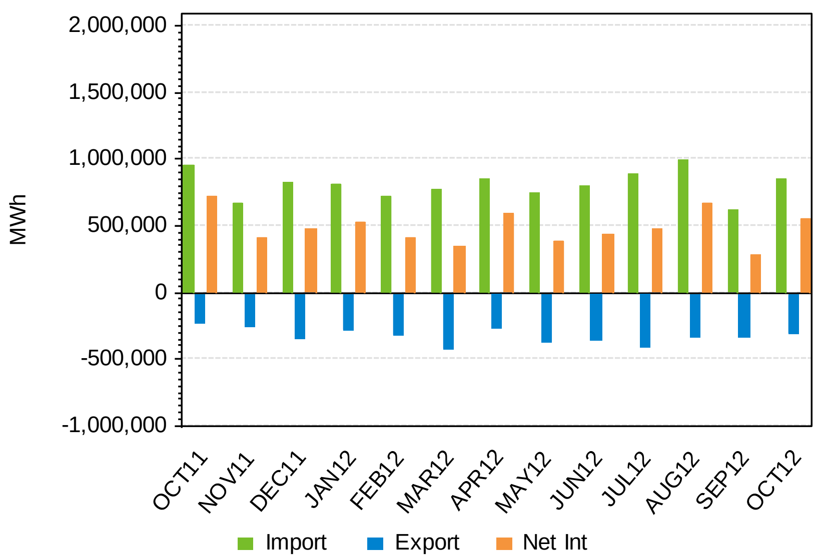




Net Interchange, Last 13 Mos., New England Control Area
Real-Time Market, All Hours

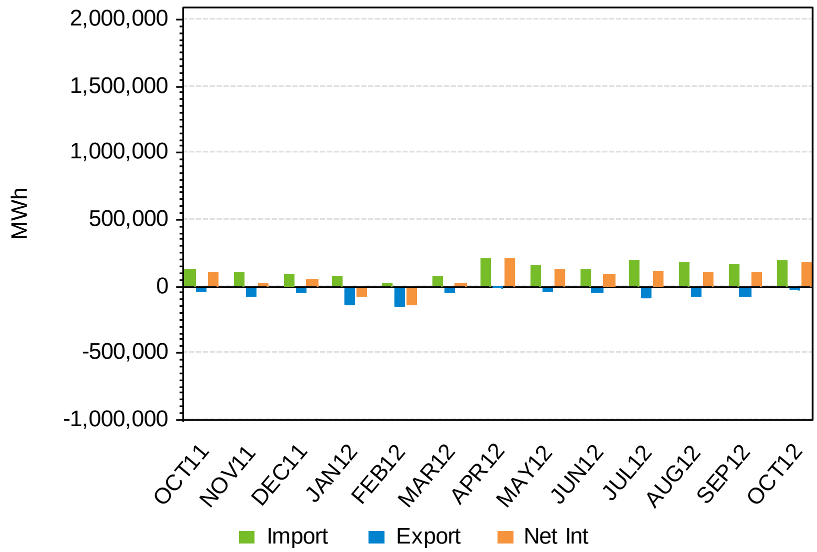


Net Interchange, Last 13 Mos., New England Control Area
Real-Time Market, On-Peak Hours

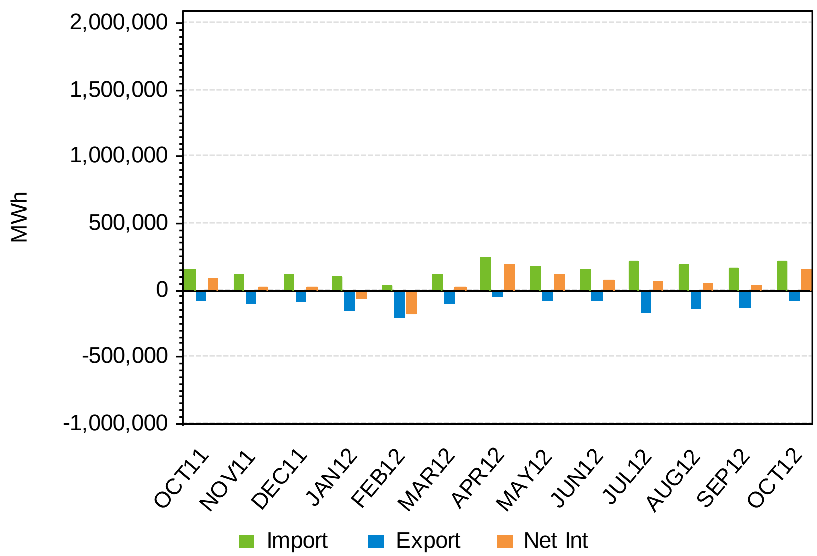


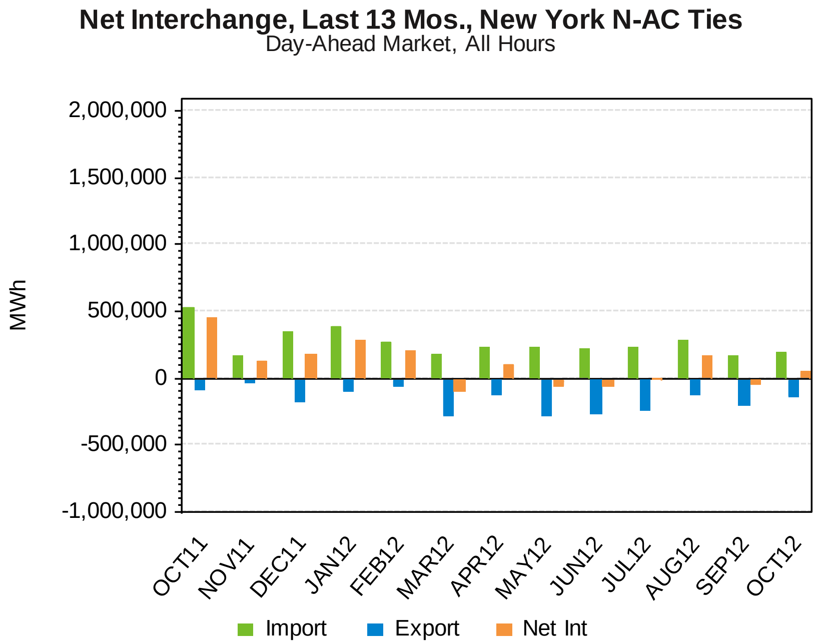
5.3 Net Interchange Summary by Interface, Last 13 Months

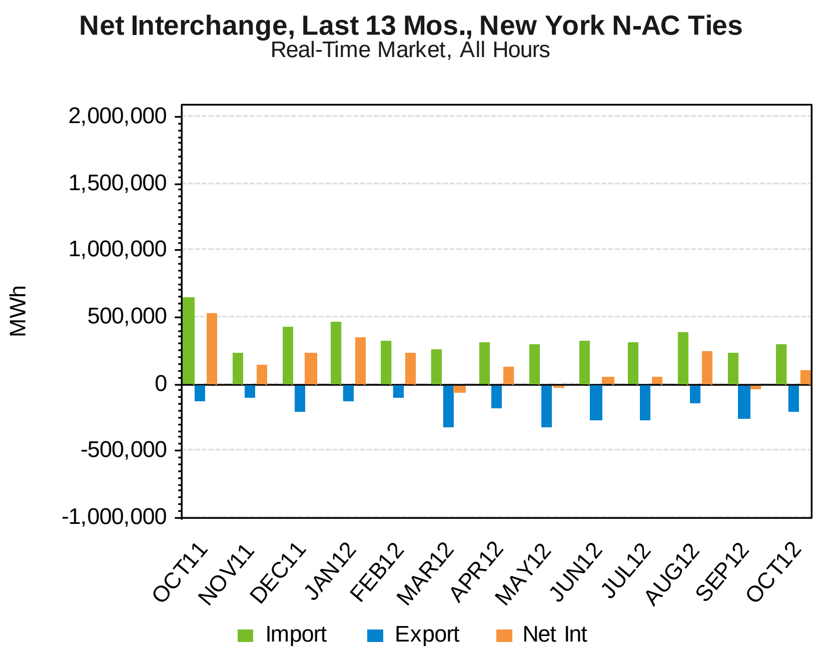
Net Interchange, Last 13 Mos., New Brunswick
Day-Ahead Market, All Hours

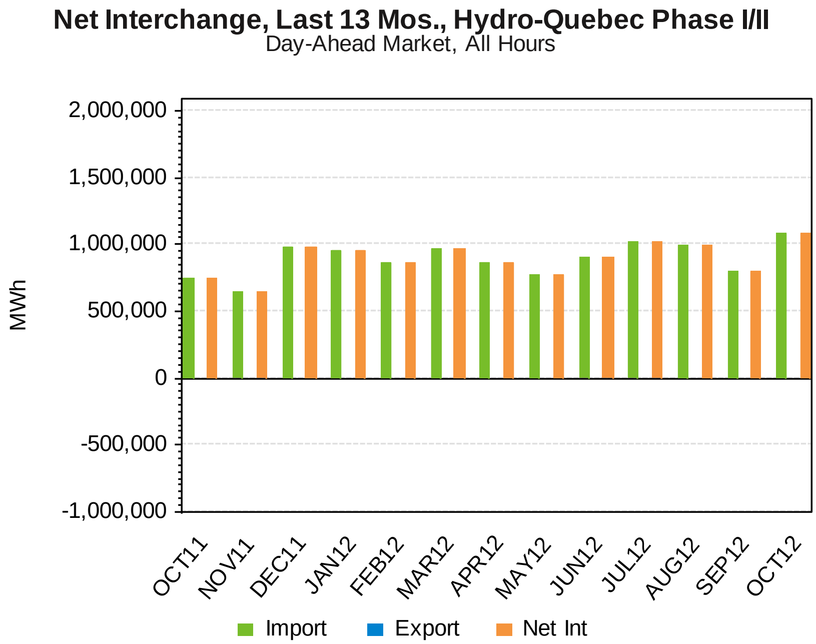


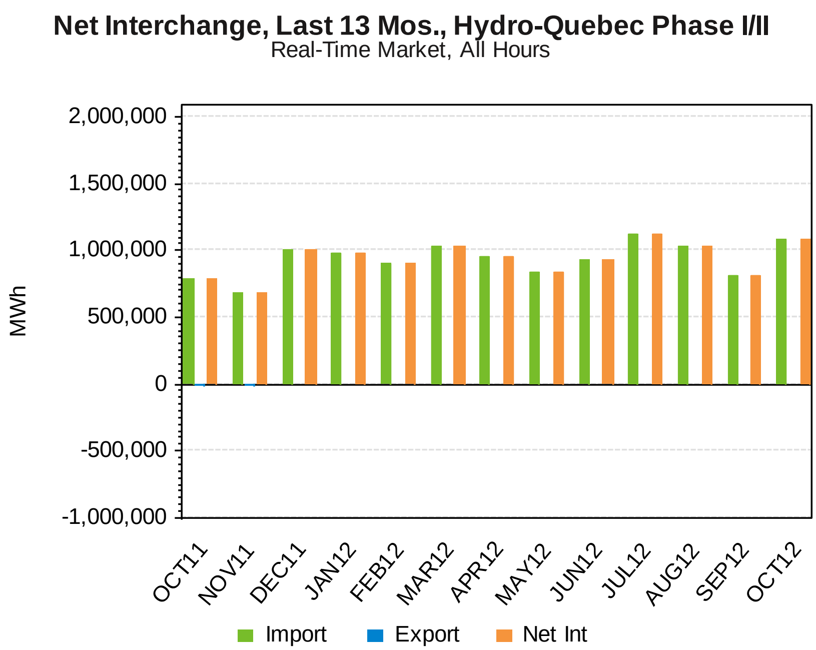
Net Interchange, Last 13 Mos., New Brunswick
Real-Time Market, All Hours

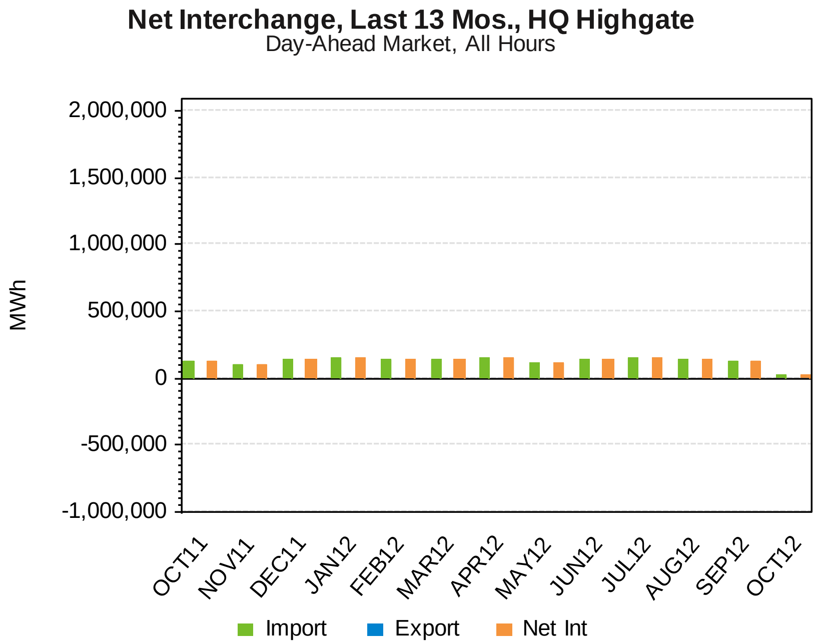


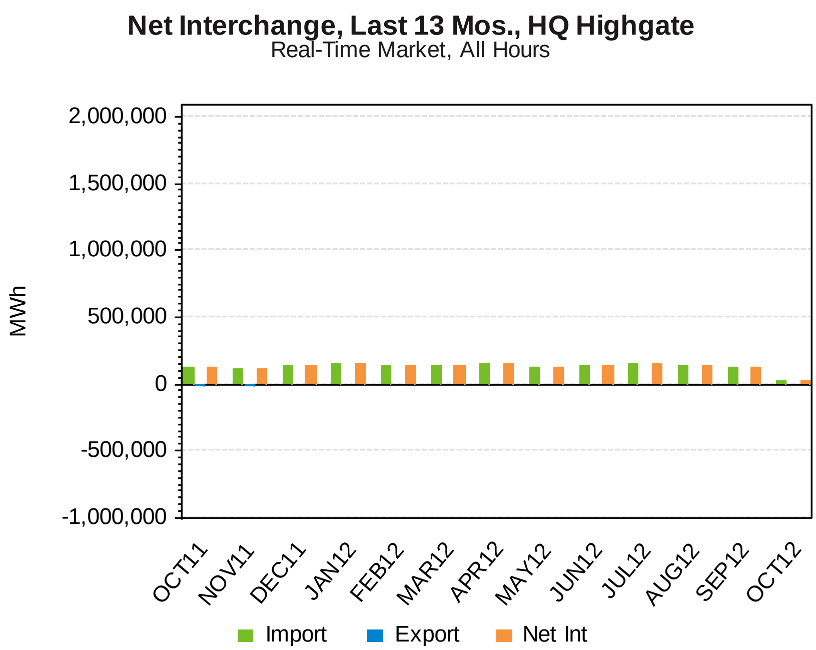

Net Interchange, Last 13 Mos., New York N-AC Ties
Day-Ahead Market, All Hours
MWh
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
OCT11
NOV11
DEC11
JAN12
FEB12
MAR12
APR12
MAY12
JUN12
JUL12
AUG12
SEP12
OCT12
Import
Export
Net Int

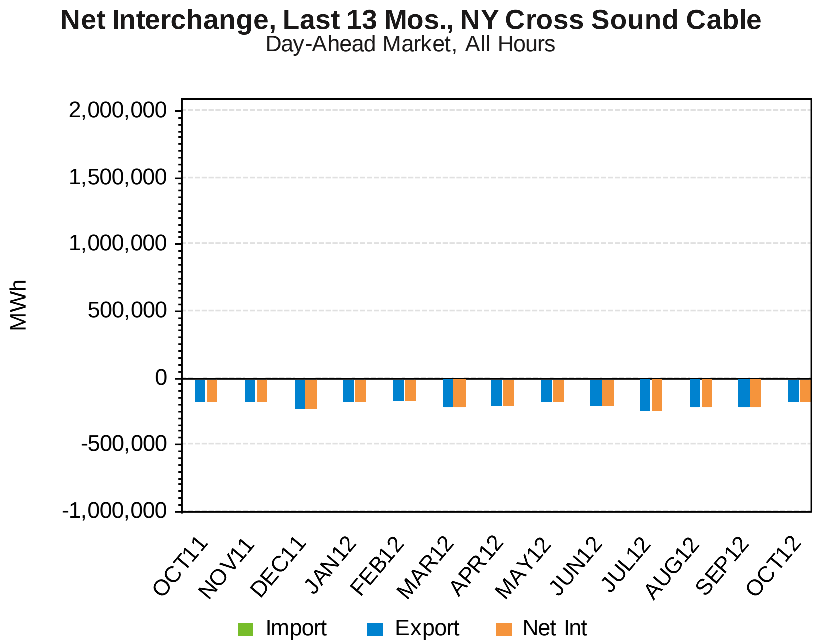

Net Interchange, Last 13 Mos., New York N-AC Ties
Real-Time Market, All Hours
MWh
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
OCT11
NOV11
DEC11
JAN12
FEB12
MAR12
APR12
MAY12
JUN12
JUL12
AUG12
SEP12
OCT12
Import
Export
Net Int

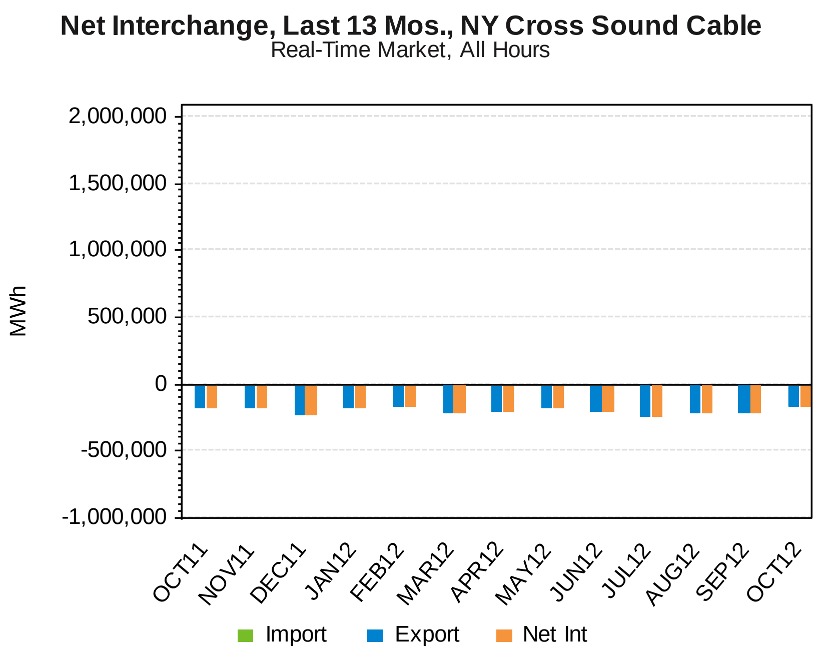

Net Interchange, Last 13 Mos., Hydro-Quebec Phase I/II
Day-Ahead Market, All Hours
MWh
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
OCT11
NOV11
DEC11
JAN12
FEB12
MAR12
APR12
MAY12
JUN12
JUL12
AUG12
SEP12
OCT12
Import
Export
Net Int

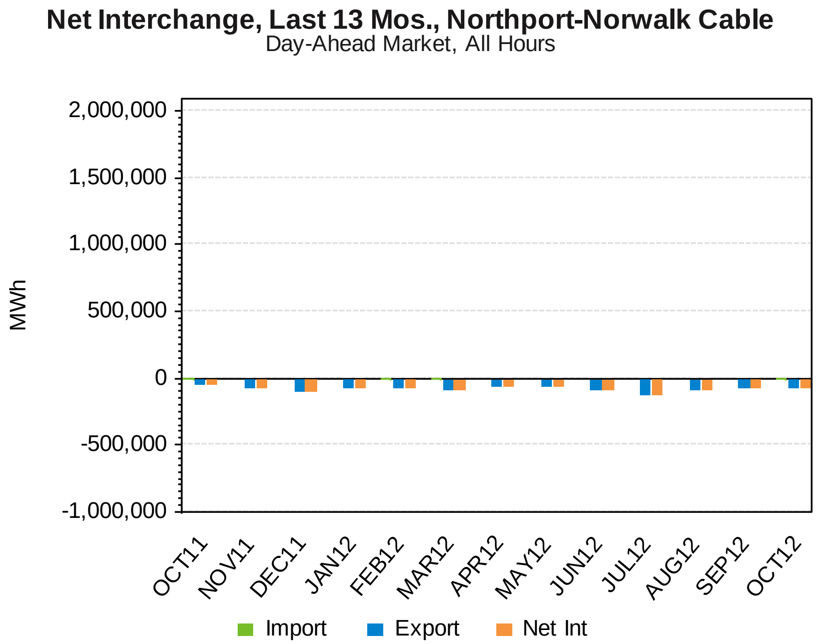

Net Interchange, Last 13 Mos., Hydro-Quebec Phase I/II
Real-Time Market, All Hours
MWh
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
OCT11
NOV11
DEC11
JAN12
FEB12
MAR12
APR12
MAY12
JUN12
JUL12
AUG12
SEP12
OCT12
Import
Export
Net Int

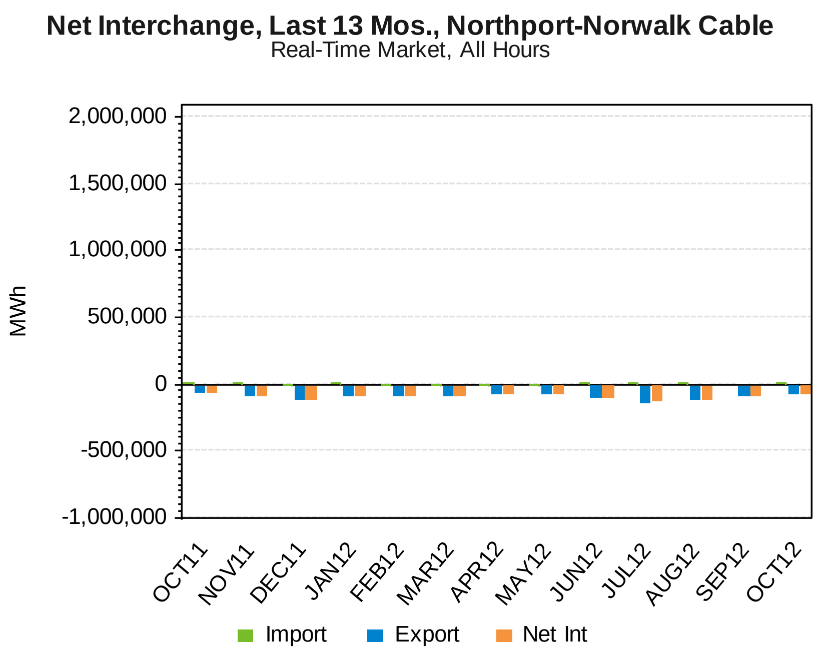

Net Interchange, Last 13 Mos., HQ Highgate
Day-Ahead Market, All Hours
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MWh
OCT11
NOV11
DEC11
JAN12
FEB12
MAR12
APR12
MAY12
JUN12
JUL12
AUG12
SEP12
OCT12
Import
Export
Net Int


Net Interchange, Last 13 Mos., HQ Highgate
Real-Time Market, All Hours
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MWh
OCT11
NOV11
DEC11
JAN12
FEB12
MAR12
APR12
MAY12
JUN12
JUL12
AUG12
SEP12
OCT12
Import
Export
Net Int


Net Interchange, Last 13 Mos., NY Cross Sound Cable
Day-Ahead Market, All Hours
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MWh
OCT11
NOV11
DEC11
JAN12
FEB12
MAR12
APR12
MAY12
JUN12
JUL12
AUG12
SEP12
OCT12
Import
Export
Net Int


Net Interchange, Last 13 Mos., NY Cross Sound Cable
Real-Time Market, All Hours
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MWh
OCT11
NOV11
DEC11
JAN12
FEB12
MAR12
APR12
MAY12
JUN12
JUL12
AUG12
SEP12
OCT12
Import
Export
Net Int


Net Interchange, Last 13 Mos., Northport-Norwalk Cable
Day-Ahead Market, All Hours
MWh
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
OCT11
NOV11
DEC11
JAN12
FEB12
MAR12
APR12
MAY12
JUN12
JUL12
AUG12
SEP12
OCT12
Import
Export
Net Int


Net Interchange, Last 13 Mos., Northport-Norwalk Cable
Real-Time Market, All Hours
MWh
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
OCT11
NOV11
DEC11
JAN12
FEB12
MAR12
APR12
MAY12
JUN12
JUL12
AUG12
SEP12
OCT12
Import
Export
Net Int

5.4 For More Information

Selectable historical hourly net interchange for the New England Control can be found on the ISO's website (select 'Interchange' in the drop-down under 'Step 1') here

Monthly, daily, and hourly summaries of New England Control Area net interchange can be found on the ISO's web site here.

The market rules governing the scheduling of external transactions can be found in Section III.1.10 "Scheduling" of the ISO's Market Rule 1 located here.

The business rules and procedures for external transactions can be found in Section 6.5, "External Transactions" in the ISO's Manual 11 – Market Operations located here.

A history of emergency purchases and sales from and to neighboring control areas can be found here.

6. Financial Transmission Rights (FTR) Auctions

FTRs are financial instruments that entitle the holder to a share of congestion collections in the Day-Ahead Market. The difference in prices (excluding losses) along a path or between any two locations on the system in the Day-Ahead Market reflects the marginal cost of transmission along that path. An FTR allows its purchaser to collect up to the full value of such congestion as consistent with the FTR's specified path and MW value.

FTRs can be acquired in three ways:

- FTR Auction – the ISO conducts periodic auctions to allow bidders to acquire and sell monthly and long-term FTRs. The bidders in the FTR auction initially define all FTRs.
- Secondary Market – The FTR secondary market is an ISO-administered bulletin board where existing FTRs are electronically bought or sold on a bilateral basis.
- Unregistered Trades – FTRs can be exchanged bilaterally outside of the ISO-administered process. However, the ISO compensates only FTR holders of record and does not recognize business done in this manner for day-ahead congestion settlement purposes.

6.1 FTR Auction Results

The results of the monthly FTR auction and any applicable long-term FTR auction are shown below.

6.1.1 Monthly Auction Summary, October 2012

Bids to Buy or Offers to Sell	On-Peak or Off-Peak	No. of Bids or Offers	Bid or Offered MW-Mos.	Bid or Offered Dollars	No. of Awards	Awarded MW-Mos.	Awarded Dollars
Buy	Off	6,193	39,903	-$1,059,748	2,250	11,798	$243,975
Buy	On	8,581	54,991	-$1,544,745	2,965	15,291	$575,040
Buy	Buy Total	14,774	94,894	-$2,604,493	5,215	27,089	$819,016
Sell	Off	2,976	5,946	$375,602	508	1,083	$12,134
Sell	On	2,771	5,343	$640,926	328	891	$13,884
Sell	Sell Total	5,747	11,289	$1,016,528	836	1,974	$26,018
Grand Total	Grand Total	20,521	106,182	-$1,587,965	6,051	29,062	$845,033

6.1.2 Number of Auction Participants, October 2012

Auction Period	Monthly or Long-Term	No. of Bidders
Oct 2012	MO	39

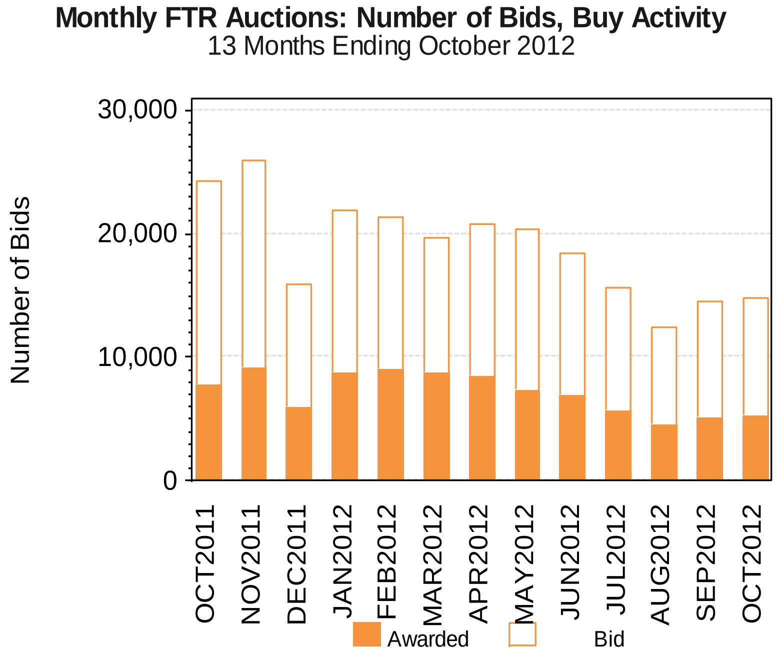
6.1.3 Monthly FTR Auction Results, Last 13 Months

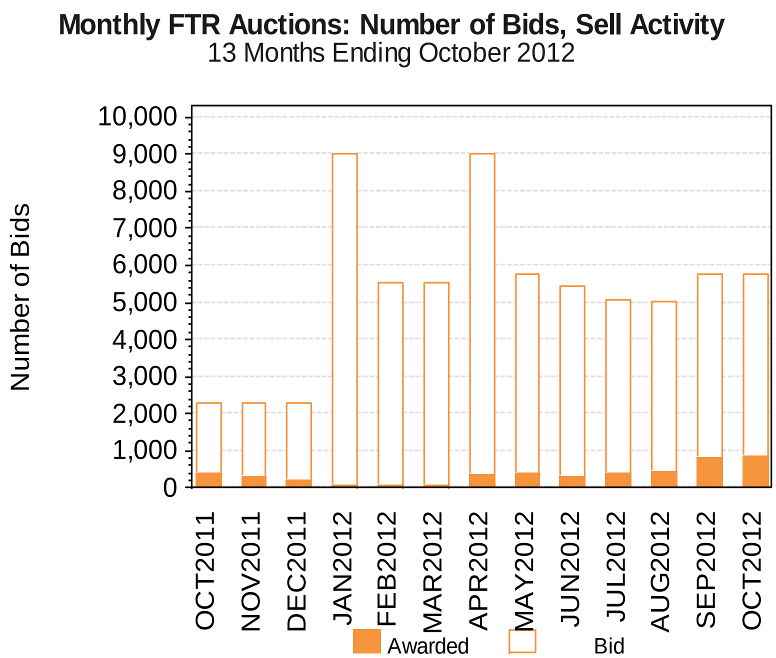
Auction Month	Bids to Buy or Offers to Sell	No. of Bids or Offers	Bid or Offered MW-Mos.	Bid or Offered Dollars	No. of Awards	Awarded MW-Mos.	Awarded Dollars
OCT 2011	Buy	24,295	190,013	-$5,030,310	7,701	31,968	$612,983
OCT 2011	Sell	2,264	7,483	$795,954	393	927	-$97,669
OCT 2011	Tot	26,559	197,497	-$4,234,356	8,094	32,894	$515,314
NOV 2011	Buy	25,885	190,755	-$4,226,589	9,136	37,949	$654,934
NOV 2011	Sell	2,304	7,911	$844,677	273	839	-$42,727
NOV 2011	Tot	28,189	198,666	-$3,381,912	9,409	38,788	$612,207
DEC 2011	Buy	15,867	102,914	-$2,690,339	5,941	32,441	$577,003
DEC 2011	Sell	2,290	7,628	$826,987	175	600	-$240

Auction Month	Bids to Buy or Offers to Sell	No. of Bids or Offers	Bid or Offered MW-Mos.	Bid or Offered Dollars	No. of Awards	Awarded MW-Mos.	Awarded Dollars
DEC 2011	Tot	18,157	110,543	-$1,863,352	6,116	33,041	$576,763
JAN 2012	Buy	21,891	120,341	-$3,196,004	8,639	38,240	$602,666
JAN 2012	Sell	9,025	15,977	$2,201,853	76	82	-$1,796
JAN 2012	Tot	30,916	136,318	-$994,151	8,715	38,322	$600,870
FEB 2012	Buy	21,286	117,218	-$2,527,638	8,938	37,305	$446,091
FEB 2012	Sell	5,519	11,116	$1,394,391	41	79	-$2,008
FEB 2012	Tot	26,805	128,334	-$1,133,247	8,979	37,384	$444,083
MAR 2012	Buy	19,682	103,175	-$2,867,067	8,699	33,986	$261,480
MAR 2012	Sell	5,519	11,112	$1,033,455	75	110	-$3,279
MAR 2012	Tot	25,201	114,287	-$1,833,612	8,774	34,096	$258,201
APR 2012	Buy	20,781	92,012	-$2,949,500	8,394	28,861	$216,211
APR 2012	Sell	9,011	15,593	$1,526,384	339	1,046	-$3,653
APR 2012	Tot	29,792	107,605	-$1,423,116	8,733	29,907	$212,558
MAY 2012	Buy	20,414	102,933	-$3,698,082	7,315	28,092	$235,124
MAY 2012	Sell	5,760	11,307	$995,086	382	1,281	-$27,092
MAY 2012	Tot	26,174	114,240	-$2,702,996	7,697	29,373	$208,032
JUN 2012	Buy	18,377	100,445	-$2,014,948	6,825	29,937	$210,588
JUN 2012	Sell	5,419	11,209	$1,068,278	299	1,174	-$9,772
JUN 2012	Tot	23,796	111,654	-$946,670	7,124	31,111	$200,816
JUL 2012	Buy	15,622	115,867	-$2,322,107	5,561	33,360	$724,262
JUL 2012	Sell	5,073	11,054	$1,095,860	370	1,475	-$24,244
JUL 2012	Tot	20,695	126,920	-$1,226,247	5,931	34,835	$700,018
AUG 2012	Buy	12,430	90,791	-$2,941,216	4,482	27,738	$612,874
AUG 2012	Sell	5,029	11,209	$1,101,544	432	1,654	$940
AUG 2012	Tot	17,459	102,001	-$1,839,673	4,914	29,393	$613,814
SEP 2012	Buy	14,478	91,989	-$2,727,385	5,099	24,638	$607,119
SEP 2012	Sell	5,755	11,383	$794,712	797	1,924	$36,706
SEP 2012	Tot	20,233	103,372	-$1,932,672	5,896	26,563	$643,824
OCT 2012	Buy	14,774	94,894	-$2,604,493	5,215	27,089	$819,016
OCT 2012	Sell	5,747	11,289	$1,016,528	836	1,974	$26,018
OCT 2012	Tot	20,521	106,182	-$1,587,965	6,051	29,062	$845,033

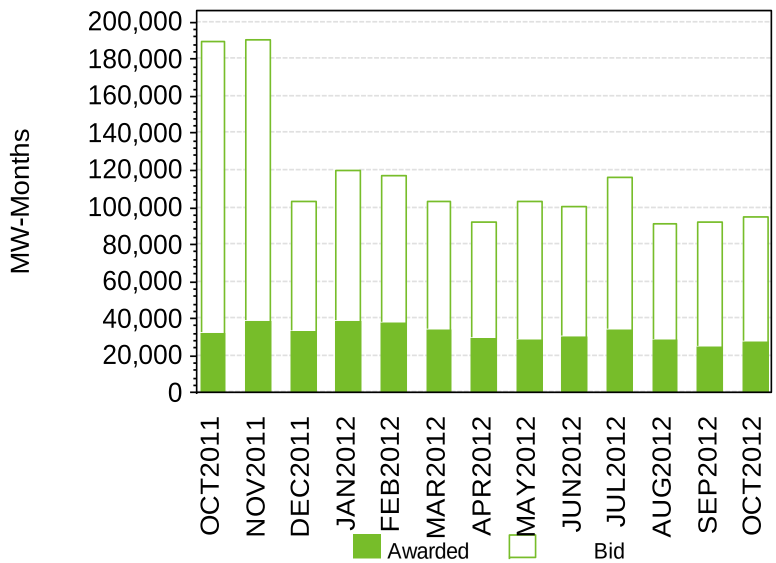
6.2 Monthly FTR Auction Results, Last 13 Months

The next series of graphs show summaries of FTR Auction activity over the last 13 months, including bids to buy monthly FTRs and offers to sell long-term FTRs into each monthly auction.

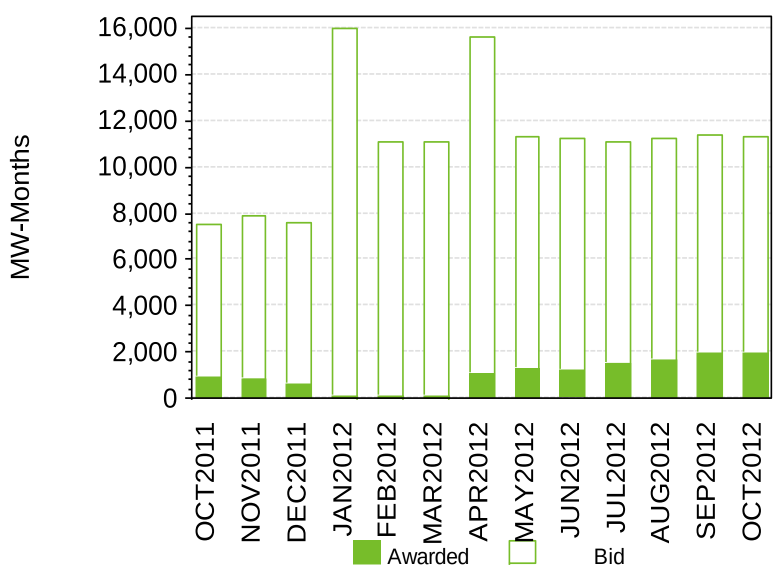

Monthly FTR Auctions: Number of Bids, Buy Activity
13 Months Ending October 2012
Number of Bids
30,000
20,000
10,000
0
OCT2011
NOV2011
DEC2011
JAN2012
FEB2012
MAR2012
APR2012
MAY2012
JUN2012
JUL2012
AUG2012
SEP2012
OCT2012
Awarded
Bid

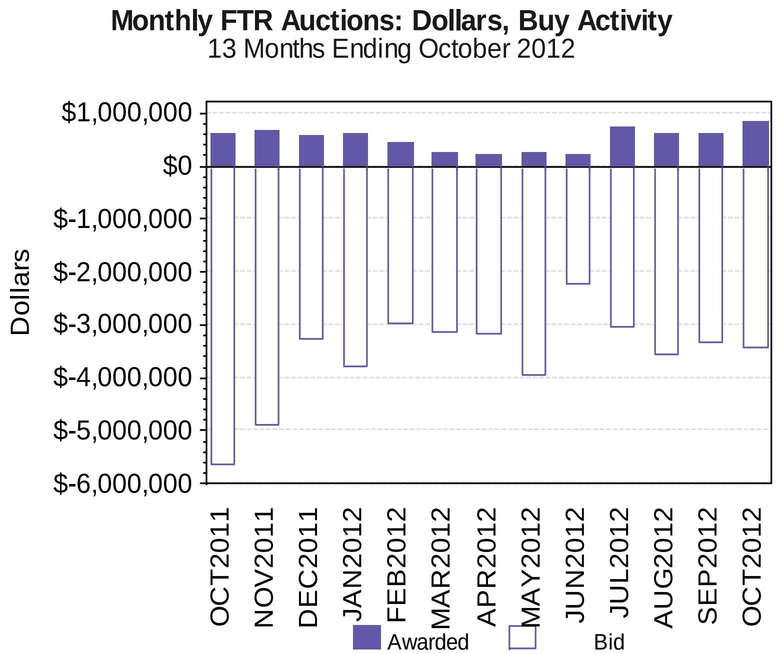

Monthly FTR Auctions: Number of Bids, Sell Activity
13 Months Ending October 2012
Number of Bids
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
OCT2011
NOV2011
DEC2011
JAN2012
FEB2012
MAR2012
APR2012
MAY2012
JUN2012
JUL2012
AUG2012
SEP2012
OCT2012
Awarded
Bid

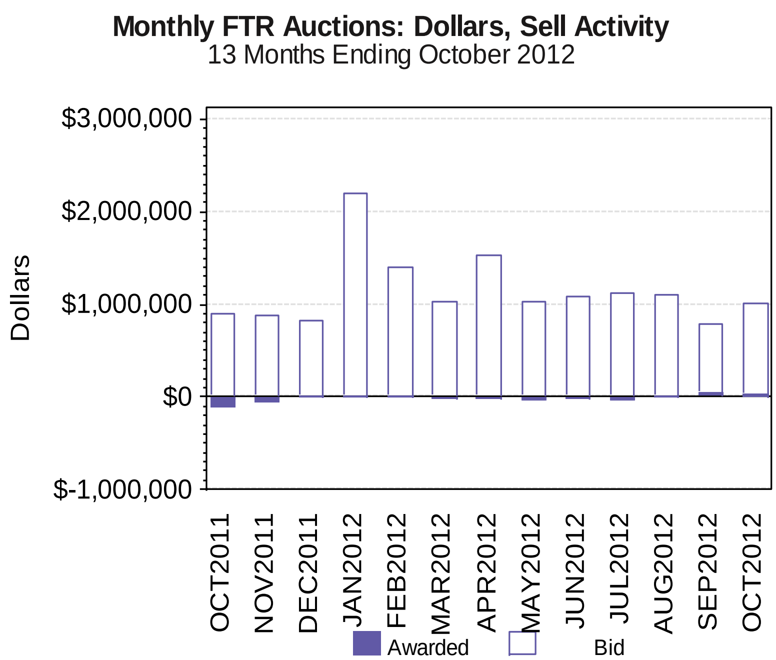
Monthly FTR Auctions: MW-Months, Buy Activity
13 Months Ending October 2012



Monthly FTR Auctions: MW-Months, Sell Activity
13 Months Ending October 2012

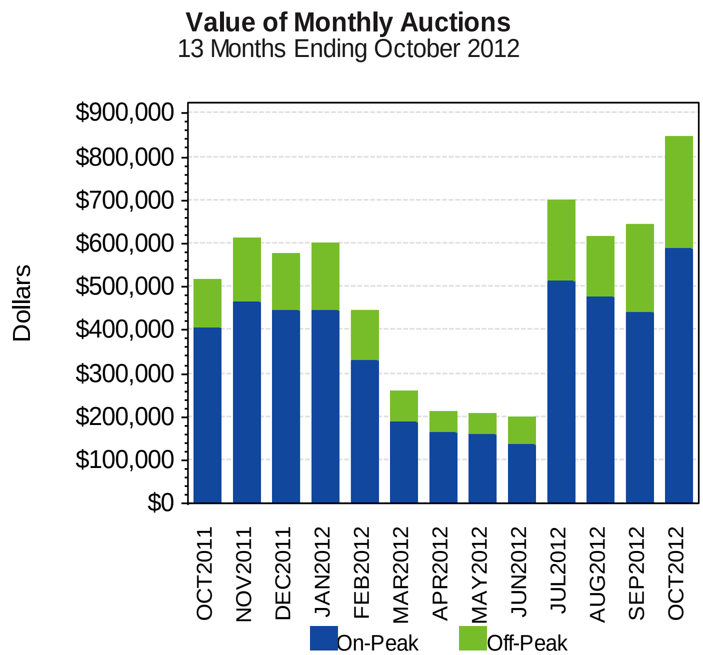


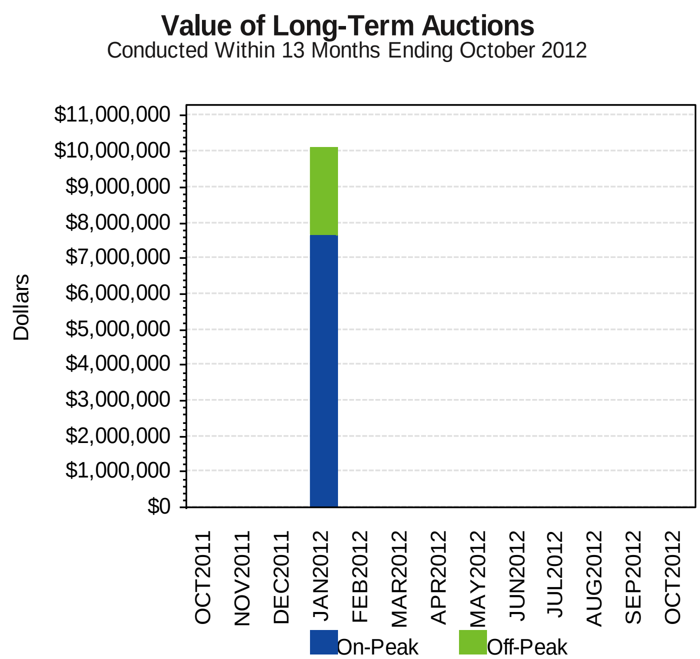

Monthly FTR Auctions: Dollars, Buy Activity
13 Months Ending October 2012
Dollars
$1,000,000
$0
$-1,000,000
$-2,000,000
$-3,000,000
$-4,000,000
$-5,000,000
$-6,000,000
OCT2011
NOV2011
DEC2011
JAN2012
FEB2012
MAR2012
APR2012
MAY2012
JUN2012
JUL2012
AUG2012
SEP2012
OCT2012
Awarded
Bid

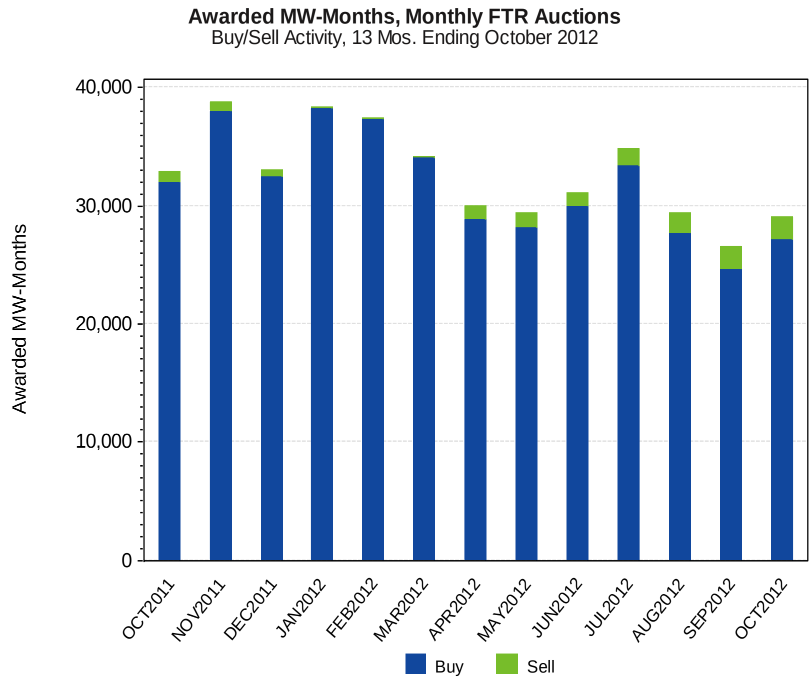

Monthly FTR Auctions: Dollars, Sell Activity
13 Months Ending October 2012
Dollars
$3,000,000
$2,000,000
$1,000,000
$0
$-1,000,000
OCT2011
NOV2011
DEC2011
JAN2012
FEB2012
MAR2012
APR2012
MAY2012
JUN2012
JUL2012
AUG2012
SEP2012
OCT2012
Awarded
Bid

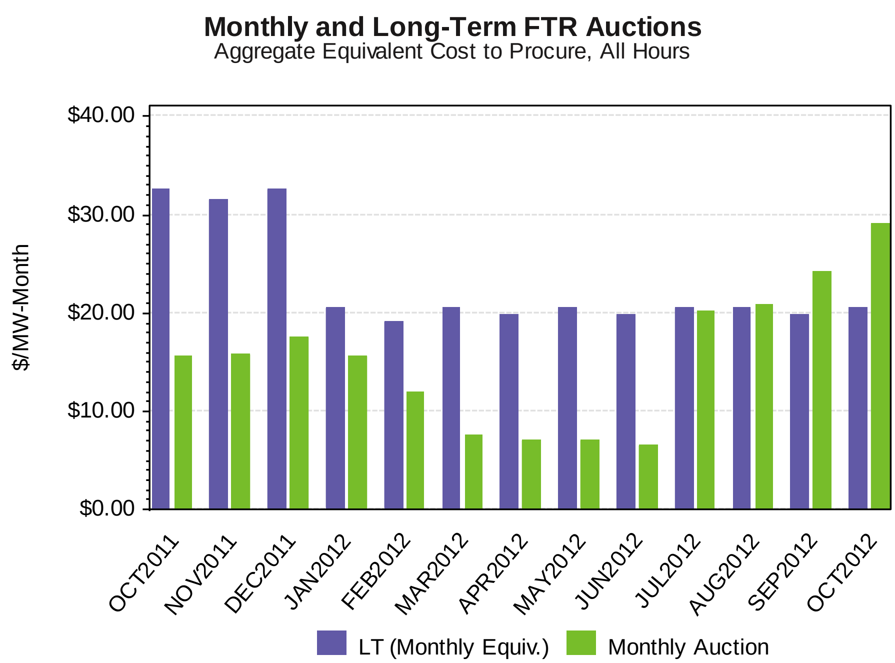
6.3 Auction Value, Last 13 Months

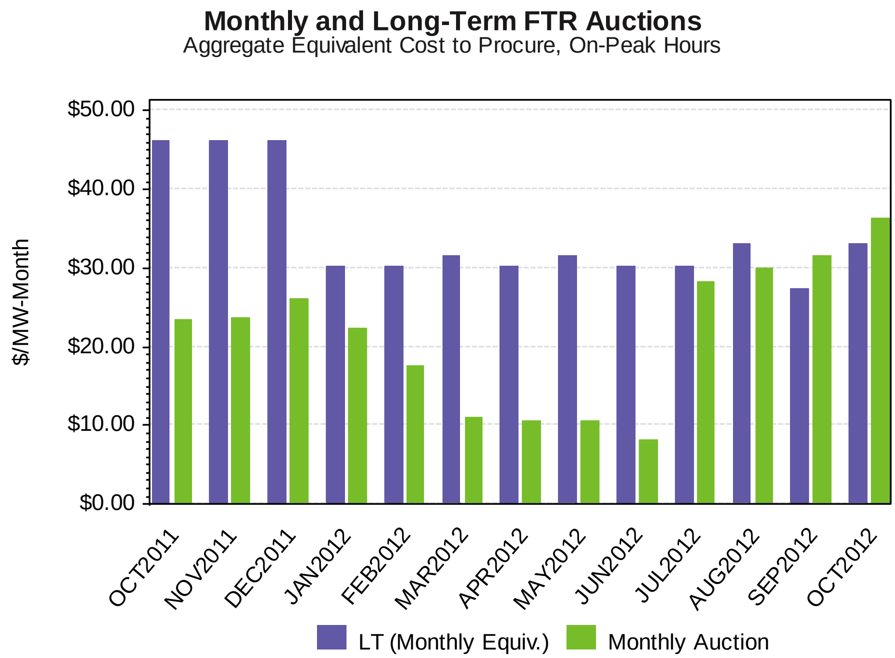
The next series of graphs show summaries of FTR Auction value and on/off-peak activity over the last 13 months.

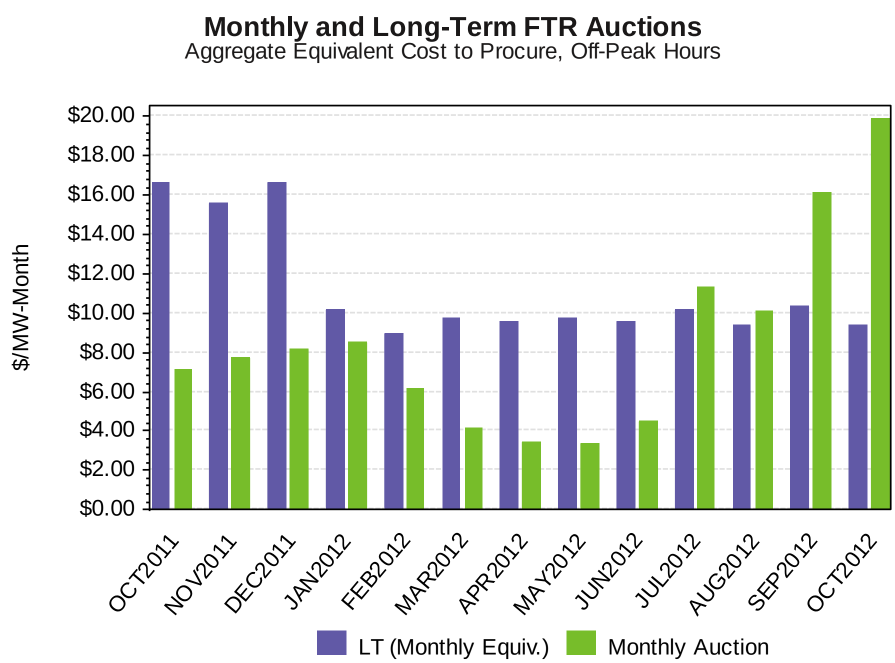





Awarded MW-Months, Monthly FTR Auctions
Buy/Sell Activity, 13 Mos. Ending October 2012
Awarded MW-Months
40,000
30,000
20,000
10,000
0
OCT2011
NOV2011
DEC2011
JAN2012
FEB2012
MAR2012
APR2012
MAY2012
JUN2012
JUL2012
AUG2012
SEP2012
OCT2012
Buy
Sell


Monthly and Long-Term FTR Auctions
Aggregate Equivalent Cost to Procure, All Hours
$/MW-Month
$40.00
$30.00
$20.00
$10.00
$0.00
OCT2011
NOV2011
DEC2011
JAN2012
FEB2012
MAR2012
APR2012
MAY2012
JUN2012
JUL2012
AUG2012
SEP2012
OCT2012
LT (Monthly Equiv.)
Monthly Auction


Monthly and Long-Term FTR Auctions
Aggregate Equivalent Cost to Procure, On-Peak Hours
$/MW-Month
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
OCT2011
NOV2011
DEC2011
JAN2012
FEB2012
MAR2012
APR2012
MAY2012
JUN2012
JUL2012
AUG2012
SEP2012
OCT2012
LT (Monthly Equiv.)
Monthly Auction


Monthly and Long-Term FTR Auctions
Aggregate Equivalent Cost to Procure, Off-Peak Hours
$/MW-Month
$20.00
$18.00
$16.00
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$0.00
OCT2011
NOV2011
DEC2011
JAN2012
FEB2012
MAR2012
APR2012
MAY2012
JUN2012
JUL2012
AUG2012
SEP2012
OCT2012
LT (Monthly Equiv.)
Monthly Auction

6.4 For More Information

The market rules governing the FTR auctions can be found in Section III.7 "Financial Transmission Rights Auctions" of the ISO's Market Rule 1 located here.

The business rules and procedures for FTRs can be found in Section 6.5, "External Transactions" in the ISO's Manual 6 – Financial Transmission Rights located here.

Information about the monthly and long-term FTR auctions can be found on the ISO's web site here.

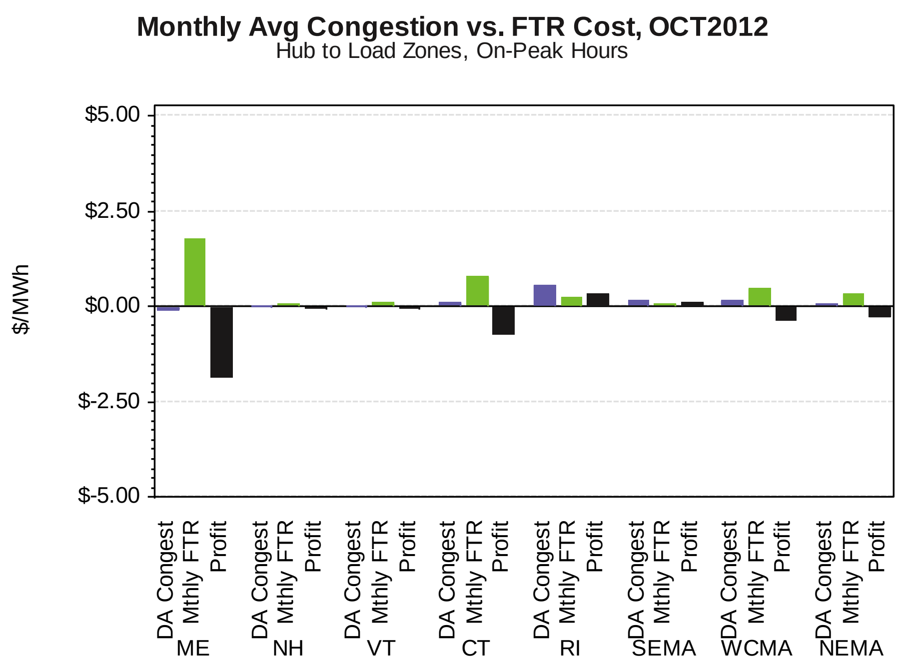
7. Effectiveness of FTRs

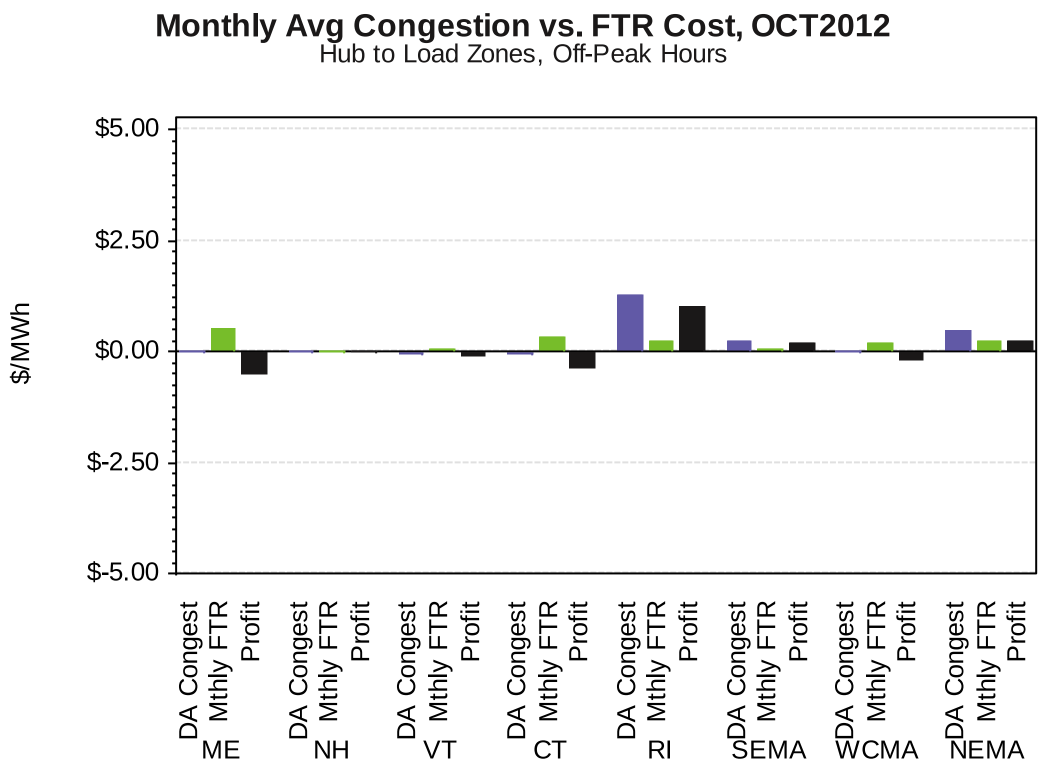
7.1 FTRs as a Congestion Hedging Instrument

Congestion costs occur in the Day-Ahead and Real-Time Markets between locations on the system when the most economic power cannot be transferred to needed load areas without violating transmission limits. These costs are embedded in the congestion component of LMP and its difference between locations. Customers who wish to protect against these real-time costs can do so by scheduling in the Day-Ahead Market. In turn, to hedge against day-ahead congestion costs, customers can obtain FTRs.

To analyze congestion and the effectiveness of the FTR market in managing the costs of congestion in New England, day-ahead congestion costs are examined in relation to FTR auction path clearing prices. Transmission paths from the Hub to the various New England Load Zones are examined in this section. In the following exhibits, monthly on-peak auction clearing prices are compared to the average day-ahead congestion components of prices for the month for each Hub-to-zone path. All units are presented in $/MWh equivalents.

Note that the exhibits are for illustration only, and do not indicate whether FTRs were actually owned by any market participant for the paths shown.





7.2 Profitability of Monthly FTRs, 13 Mos. Ending October 2012, On-Peak Hours, in $/MWh, from Hub to Load Zones

A comparison of the “profitability” or the success of the hedge that the illustrated FTRs provided over the last thirteen months is presented below.

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
ME	Oct-11	$0.58	-$0.52	$1.10
ME	Nov-11	-$0.45	-$0.03	-$0.42
ME	Dec-11	$0.01	$0.06	-$0.06
ME	Jan-12	$0.14	$0.76	-$0.61
ME	Feb-12	$0.05	$0.53	-$0.49
ME	Mar-12	$2.18	$0.18	$1.99
ME	Apr-12	$0.68	$0.74	-$0.06
ME	May-12	$3.13	$0.26	$2.87
ME	Jun-12	-$1.25	$1.25	-$2.50
ME	Jul-12	$0.10	$1.75	-$1.65
ME	Aug-12	$0.09	$0.57	-$0.48
ME	Sep-12	$3.87	$1.64	$2.23
ME	Oct-12	-$0.08	$1.78	-$1.85

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
NH	Oct-11	$0.05	-$0.31	$0.36
NH	Nov-11	-$0.04	-$0.08	$0.03
NH	Dec-11	$0.01	-$0.05	$0.06
NH	Jan-12	$0.01	$0.00	$0.01
NH	Feb-12	$0.03	-$0.04	$0.07
NH	Mar-12	-$0.01	$0.03	-$0.05
NH	Apr-12	$0.04	-$0.07	$0.12
NH	May-12	$0.26	$0.01	$0.25
NH	Jun-12	-$0.70	$0.03	-$0.74
NH	Jul-12	$0.09	$0.11	-$0.03
NH	Aug-12	$0.04	$0.02	$0.03
NH	Sep-12	$0.04	$0.04	$0.00
NH	Oct-12	$0.02	$0.04	-$0.03

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
VT	Oct-11	$0.17	$0.38	-$0.22
VT	Nov-11	$0.40	$0.12	$0.28
VT	Dec-11	$0.00	$0.11	-$0.10
VT	Jan-12	$0.01	$0.02	-$0.01
VT	Feb-12	$0.03	$0.06	-$0.02
VT	Mar-12	$0.00	$0.06	-$0.06
VT	Apr-12	$0.06	-$0.02	$0.08
VT	May-12	$0.36	$0.05	$0.31
VT	Jun-12	-$0.75	$0.03	-$0.78
VT	Jul-12	$0.05	$0.13	-$0.08
VT	Aug-12	$0.04	$0.02	$0.03
VT	Sep-12	$0.00	$0.02	-$0.02
VT	Oct-12	$0.03	$0.08	-$0.05

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
CT	Oct-11	$0.82	$1.33	-$0.51
CT	Nov-11	$1.25	$1.12	$0.13
CT	Dec-11	$0.02	$0.91	-$0.90
CT	Jan-12	$0.05	$0.55	-$0.50
CT	Feb-12	$0.22	$0.44	-$0.21
CT	Mar-12	$0.05	$0.38	-$0.33
CT	Apr-12	$0.38	$0.32	$0.06
CT	May-12	$3.20	$0.35	$2.85
CT	Jun-12	$0.55	$0.59	-$0.04
CT	Jul-12	$1.34	$1.59	-$0.25
CT	Aug-12	$0.92	$0.69	$0.23
CT	Sep-12	$0.48	$1.17	-$0.69
CT	Oct-12	$0.08	$0.80	-$0.71

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
RI	Oct-11	-$0.02	-$0.36	$0.34
RI	Nov-11	-$0.06	-$0.06	$0.01
RI	Dec-11	-$0.02	-$0.01	-$0.01
RI	Jan-12	$0.01	$0.01	$0.01
RI	Feb-12	$0.05	-$0.04	$0.09
RI	Mar-12	$0.05	$0.03	$0.02
RI	Apr-12	$0.09	$0.03	$0.06
RI	May-12	$0.68	$0.02	$0.66
RI	Jun-12	$2.03	$0.07	$1.95
RI	Jul-12	$0.20	$0.18	$0.01
RI	Aug-12	$0.11	$0.14	-$0.03
RI	Sep-12	$0.41	$0.18	$0.23
RI	Oct-12	$0.56	$0.22	$0.34

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
SEMA	Oct-11	-$0.16	-$0.32	$0.17
SEMA	Nov-11	-$0.10	-$0.08	-$0.02
SEMA	Dec-11	-$0.02	-$0.04	$0.02
SEMA	Jan-12	$0.01	$0.00	$0.01
SEMA	Feb-12	$0.03	-$0.04	$0.07
SEMA	Mar-12	$0.01	$0.03	-$0.03
SEMA	Apr-12	$0.05	$0.02	$0.04
SEMA	May-12	$0.26	$0.03	$0.23
SEMA	Jun-12	-$0.18	$0.04	-$0.22
SEMA	Jul-12	$0.11	$0.13	-$0.01
SEMA	Aug-12	$0.06	$0.04	$0.03
SEMA	Sep-12	$0.09	$0.07	$0.02
SEMA	Oct-12	$0.17	$0.07	$0.10

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
WCMA	Oct-11	$0.78	$0.20	$0.58
WCMA	Nov-11	$0.97	$0.18	$0.79
WCMA	Dec-11	$0.04	$0.18	-$0.14
WCMA	Jan-12	$0.10	$0.18	-$0.08
WCMA	Feb-12	$0.36	$0.10	$0.26
WCMA	Mar-12	$0.11	$0.19	-$0.08
WCMA	Apr-12	$0.68	$0.11	$0.57
WCMA	May-12	$4.69	$0.20	$4.49
WCMA	Jun-12	$1.31	$0.38	$0.94
WCMA	Jul-12	$1.42	$0.58	$0.84
WCMA	Aug-12	$1.07	$0.36	$0.71
WCMA	Sep-12	$1.17	$0.66	$0.51
WCMA	Oct-12	$0.13	$0.47	-$0.34

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
NEMA	Oct-11	$0.29	-$0.24	$0.53
NEMA	Nov-11	$0.39	$0.07	$0.32
NEMA	Dec-11	$0.04	$0.09	-$0.05
NEMA	Jan-12	$0.01	$0.13	-$0.12
NEMA	Feb-12	$0.03	$0.04	-$0.01
NEMA	Mar-12	$0.00	$0.08	-$0.08
NEMA	Apr-12	$0.12	$0.06	$0.06
NEMA	May-12	$0.29	$0.16	$0.12
NEMA	Jun-12	-$0.68	$0.27	-$0.95
NEMA	Jul-12	$0.10	$0.28	-$0.18
NEMA	Aug-12	$0.13	$0.15	-$0.02
NEMA	Sep-12	$2.58	$0.25	$2.33
NEMA	Oct-12	$0.04	$0.32	-$0.27

8. Auction Revenue Rights

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

The ARR process allocates dollars to:

- *Excepted Transactions* – special grandfathered 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.

The following table provides a more detailed view of how auction revenues are allocated through the ARR and QUA process by including the dollars allocated to each component of the ARR process for each of the last 13 months.

Month	Net FTR Auction Revenue	Excepted Transactions	NEMA Contracts	Load Share	Total ARR Allocation	QUA Allocation	IARR Allocation	Total Auction Distribution
Oct-11	-$1,895,027	$12	$4,945	$1,683,587	$1,688,544	$206,483	$0	$1,895,027
Nov-11	-$1,947,413	$14	$5,842	$1,674,948	$1,680,804	$266,609	$0	$1,947,413
Dec-11	-$1,956,476	$19	$6,534	$1,821,885	$1,828,438	$128,038	$0	$1,956,476
Jan-12	-$1,455,573	$36	$7,096	$1,357,268	$1,364,400	$0	$91,174	$1,455,573
Feb-12	-$1,243,645	$19	$3,396	$1,169,639	$1,173,054	$0	$70,590	$1,243,645
Mar-12	-$1,112,905	$0	$6,027	$1,038,690	$1,044,717	$0	$68,187	$1,112,905
Apr-12	-$1,039,691	$0	$5,216	$966,001	$971,218	$0	$68,473	$1,039,691
May-12	-$1,062,735	$0	$6,498	$996,718	$1,003,216	$0	$59,519	$1,062,735
Jun-12	-$1,027,949	$0	$5,218	$959,501	$964,719	$0	$63,231	$1,027,949
Jul-12	-$1,554,722	$0	$9,052	$1,481,571	$1,490,624	$0	$64,098	$1,554,722
Aug-12	-$1,468,518	$0	$10,812	$1,390,842	$1,401,654	$0	$66,864	$1,468,518
Sep-12	-$1,470,957	$0	$10,183	$1,395,429	$1,405,612	$0	$65,345	$1,470,957
Oct-12	-$1,699,737	$0	$17,190	$1,604,973	$1,622,162	$0	$77,575	$1,699,737

The following tables display the total distribution of On- and Off-Peak ARR dollars to the various Load Zones for each of the last 13 months. The sum across zones totals to the 'Total ARR Allocation' column in the preceding table.

On Peak								
Month	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Oct-11	$18,278	$35,896	$61,473	$795,686	$18,556	$43,597	$174,204	$147,139
Nov-11	$20,906	$31,244	$51,295	$776,661	$16,933	$36,885	$159,802	$144,026
Dec-11	$40,104	$33,580	$55,277	$840,153	$19,758	$41,882	$194,882	$166,770
Jan-12	$165,168	$17,523	$26,479	$548,590	$9,633	$20,284	$132,449	$108,360
Feb-12	$119,276	$17,857	$28,005	$493,053	$8,722	$20,332	$115,217	$83,305
Mar-12	$59,278	$16,728	$26,297	$444,498	$8,509	$19,286	$128,598	$83,742
Apr-12	$94,921	$15,753	$24,576	$410,084	$7,993	$18,149	$98,694	$70,622
May-12	$53,604	$16,933	$26,369	$430,880	$7,833	$19,972	$119,613	$89,547
Jun-12	$76,611	$13,833	$23,434	$398,383	$6,797	$14,907	$104,033	$78,836
Jul-12	$204,190	$14,648	$24,676	$580,542	$9,808	$17,200	$156,725	$105,060
Aug-12	$147,679	$15,169	$24,935	$564,146	$14,566	$18,536	$179,177	$112,395
Sep-12	$175,758	$14,431	$23,819	$511,238	$12,764	$18,530	$165,831	$100,137
Oct-12	$274,489	$15,797	$25,583	$532,160	$19,138	$19,948	$158,454	$134,293

Off Peak								
Month	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Oct-11	$28,255	$5,043	$12,535	$215,252	$8,500	$19,173	$73,754	$31,202
Nov-11	$53,315	$6,028	$11,745	$227,644	$8,770	$18,902	$79,324	$37,325
Dec-11	$80,947	$5,203	$10,857	$205,238	$8,057	$17,944	$76,243	$31,544
Jan-12	$159,799	$3,291	$4,927	$109,192	$2,690	$5,710	$34,257	$16,047
Feb-12	$126,682	$3,120	$5,137	$101,819	$2,245	$5,231	$29,280	$13,774
Mar-12	$109,311	$2,805	$4,755	$89,392	$2,214	$5,068	$31,785	$12,452
Apr-12	$88,990	$2,562	$4,424	$87,290	$2,450	$4,935	$28,012	$11,763
May-12	$77,336	$2,677	$4,618	$93,070	$2,566	$6,531	$37,063	$14,606
Jun-12	$92,074	$2,505	$4,399	$88,690	$2,254	$4,795	$36,546	$16,623
Jul-12	$161,882	$2,716	$4,677	$135,149	$3,267	$5,614	$49,349	$15,120
Aug-12	$144,053	$2,530	$4,566	$102,337	$9,405	$7,927	$39,014	$15,220
Sep-12	$62,901	$3,008	$4,839	$177,190	$11,902	$9,745	$69,876	$43,645
Oct-12	$133,045	$3,019	$5,207	$127,783	$21,891	$13,479	$61,935	$75,940

8.1 For More Information

The market rules governing the FTR auctions can be found in Section III.7 "Financial Transmission Rights Auctions" of the ISO's Market Rule 1 located here.

The business rules and procedures for FTR Auction Revenue Settlement for September can be found in Section 7 and the Qualified Upgrade Award procedures can be found in Section 8 of the ISO's Manual 6 – Financial Transmission Rights located here.

The methodology for and details of ARR Contracts can be found here.

9. Reserve Markets

The twelfth Forward Reserve Market Auction, covering the Winter 2012/13 Procurement Period (October-May) cleared on August 30, 2012. The results may be found on the ISO's website at this link.

Participants must meet their cleared portfolio-based obligations by assigning them to eligible generating or dispatchable asset related demand through offering or bidding them into the Energy Market at a $/MWh rate that is greater than or equal to the Forward Reserve Threshold Price. For the month of October 2012, the threshold price was set at $54.64.

9.1 Forward Reserve Market Results

Each month, the ISO calculates an individual hourly Forward Reserve Payment Rate for each reserve product and reserve zone by reducing (on a $/MWh basis) their auction clearing price by the Forward Capacity Auction clearing price for the capacity zone associated to the reserve zone in effect for that month, adjusted pursuant to Section III.13.2.7.3(b)[1]. Payments will be further reduced by any Failure-to-Reserve or Failure-to-Activate Penalties. FRM payments by reserve zone made during the month are shown in the following table. These figures are preliminary and subject to revision during the Settlement process.

9.1.1 FRM Payment Summary by Reserve Zone, October 2012

Reserve Zone	Reserve Product	Max FRM Payment	Final FRM Credits	Failure to Reserve Penalties	Failure to Activate Penalties	Total FRM Performance	Pct. of Max.
SYSTEM	TMNSR	$392,356	$354,373	-$57,178	$0	$297,195	76%
SYSTEM	TMOR	$165,256	$156,771	-$12,775	$0	$143,996	87%
SYSTEM	TOTAL	$557,612	$511,144	-$69,953	$0	$441,191	79%
ROS	TMNSR	$204,026	$200,777	-$4,888	$0	$195,889	96%
ROS	TMOR	$25,241	$23,842	-$2,107	$0	$21,734	86%
ROS	TOTAL	$229,268	$224,619	-$6,996	$0	$217,624	95%
SWCT	TMNSR	$0	$0	$0	$0	$0	n/a
SWCT	TMOR	$59,257	$58,020	-$1,864	$0	$56,156	95%
SWCT	TOTAL	$59,257	$58,020	-$1,864	$0	$56,156	95%
CT	TMNSR	$188,330	$153,596	-$52,290	$0	$101,306	54%
CT	TMOR	$80,758	$74,909	-$8,804	$0	$66,105	82%
CT	TOTAL	$269,087	$228,505	-$61,094	$0	$167,411	62%
NEMABSTN	TMNSR	$0	$0	$0	$0	$0	n/a
NEMABSTN	TMOR	$0	$0	$0	$0	$0	n/a
NEMABSTN	TOTAL	$0	$0	$0	$0	$0	n/a

[1] Prior to the start of the Forward Capactiy Market on June 1, 2010, the auction clearing price was reduced by the ICAP Transition Rate for Unforced Capacity in effect for that month.

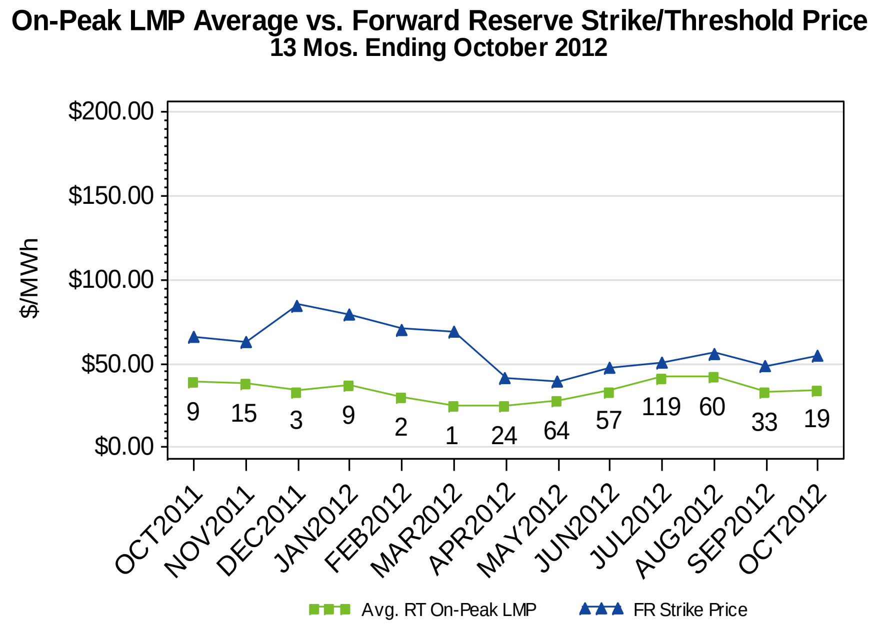
The ISO allocates Forward Reserve Credits, net of Forward Reserve Failure-to-Reserve Penalties and Forward Reserve Failure-to-Activate Penalties, to each Load Zone. The Forward Reserve charge allocation method changed on June 1, 2011. Under the new Forward Reserve Cost Allocation, the Forward Reserves Credits for TMNSR and TMOR are not allocated separately. Instead, the Forward Reserve Credits are allocated based upon System Requirements (Step 1) and Remaining Forward Reserve Credit (Step 2), if applicable. The System Requirements include the cost of procuring TMNSR and TMOR to meet the minimum requirements for the New England Control Area (Market Rule 1, Section III.9.2.1). The remaining Forward Reserve Credit includes the Incremental Cost associated with procuring Forward Reserves above the System Requirements. See Market Rule 1, Section III.9.9 Forward Reserve Charges and Manual 28, Section 2.6.2 Forward Reserve Charges for details on the two-step cost allocation approach.

FRM charges allocated to each Load Zone during the prior week are shown in the following table. These figures are also preliminary and subject to revision during the Settlement process.

9.1.2 FRM Charge Summary by Load Zone, October 2012

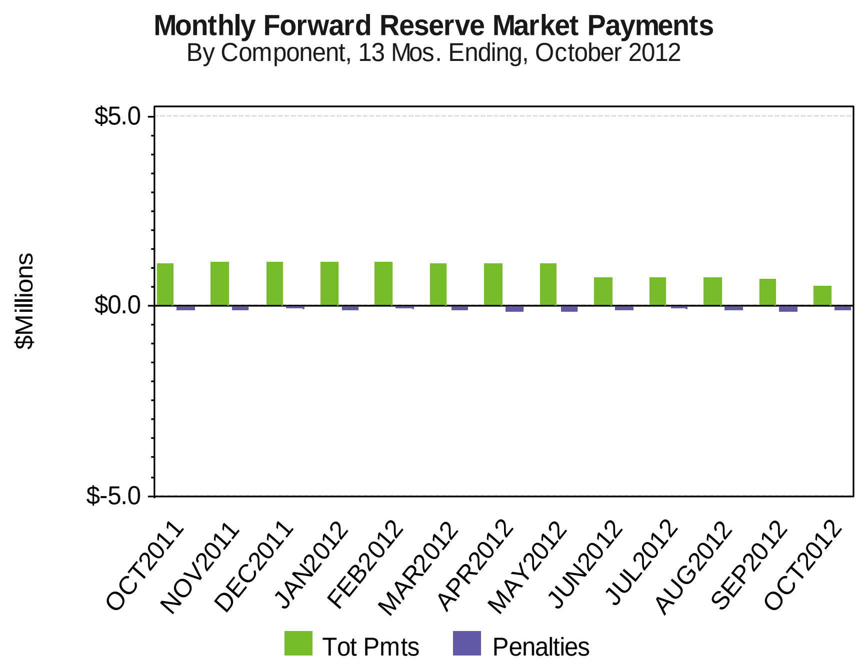
Load Zone	FRM Charge
ME	$40,295
NH	$41,736
VT	$20,661
CT	$106,406
RI	$28,146
SEMA	$52,176
WCMA	$61,401
NEMA	$90,369
ALL	$441,191

9.2 Real-Time On-Peak LMP vs. Forward Reserve Threshold Price, Last 13 Mos.



Number of times hourly RT LMP exceeded strike/threshold price during on-peak hours noted

9.3 Composition of Forward Reserve Market Payments, Last 13 Mos.



9.4 Real-Time Reserve Markets

Resources that are providing Real-Time Reserves are designated in the ISO's Energy Management System. When reserves are ample, the Real-Time Reserve price is $0. However, if there is a shortage of available reserves in a reserve zone or system-wide or reserve requirements are met through a re-dispatch of the system, non-zero Real-Time Reserve prices can result.

During the month, there were non-zero real-time reserve prices in 58 separate hours. On a reserve zone basis, non-zero prices occurred thus: CT-57 hours; NEMABSTN-58 hours; ROS-57 hours; SWCT-57 hours. The total compensation paid to assets providing real-time reserves during October 2012, and reductions in those payments for the Forward Reserve Obligation Charge are shown in the following table:

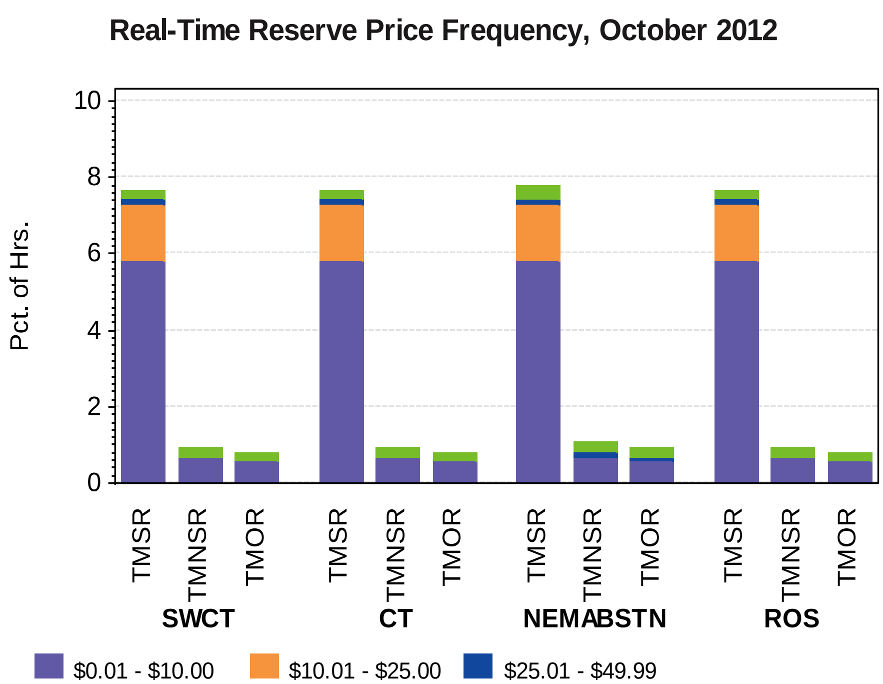
Reserve Zone	Real-Time Reserve Credits	Fwd Reserve Obligation Charges	Net Real-Time Reserve Payments
SYSTEM	$1,073,907	($240,788)	$833,118
ROS	$644,786	($152,088)	$492,698
SWCT	$193,082	($23,722)	$169,360
CT	$165,175	($64,978)	$100,197
NEMABSTN	$70,864	$0	$70,864

The ISO allocates Real Time Reserve Credits, net of Forward Reserve Energy Obligation Charges, to each Load Zone. The Real Time Reserve charges allocated to each Load Zone during the month are shown in the following table. These figures are also preliminary and subject to revision during the Settlement process.

Load Zone	Reserve Product	RT Reserve Charge
ME	TMSR	$47,955
ME	TMNSR	$19,359
ME	TMOR	$12,083
ME	ALL	$79,398
NH	TMSR	$48,210
NH	TMNSR	$19,146
NH	TMOR	$11,842
NH	ALL	$79,198
VT	TMSR	$24,105
VT	TMNSR	$9,696
VT	TMOR	$6,035
VT	ALL	$39,836
CT	TMSR	$111,667
CT	TMNSR	$41,074
CT	TMOR	$24,616
CT	ALL	$177,356
RI	TMSR	$32,153

Load Zone	Reserve Product	RT Reserve Charge
RI	TMNSR	$12,663
RI	TMOR	$7,808
RI	ALL	$52,624
SEMA	TMSR	$62,717
SEMA	TMNSR	$25,545
SEMA	TMOR	$15,930
SEMA	ALL	$104,192
WCMA	TMSR	$71,061
WCMA	TMNSR	$28,513
WCMA	TMOR	$17,734
WCMA	ALL	$117,308
NEMA	TMSR	$111,649
NEMA	TMNSR	$44,061
NEMA	TMOR	$27,497
NEMA	ALL	$183,207

The following chart shows the frequency (in percent of total hours in the month) that there were non-zero reserve market prices by reserve zone and market product.



9.5 For More Information

The market rules governing the Forward Reserve Market can be found in Section III.9 "Forward Reserve Market" of the ISO's Market Rule 1 located here.

The market rules governing Real-Time Reserve can be found in Section III.10 “Real-Time Reserve” of the ISO’s Market Rule 1 located here.

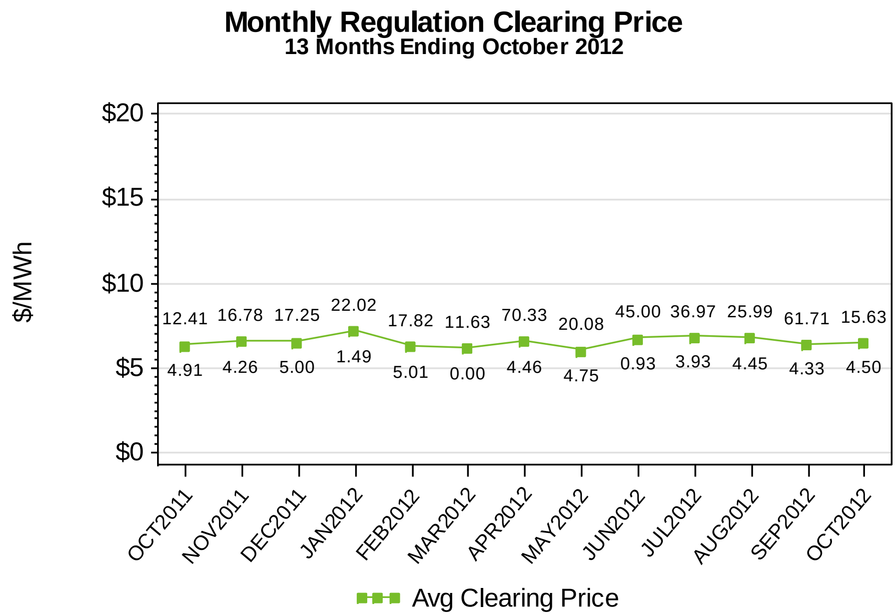
The business rules and procedures for forward and real-time reserve can be found in the ISO’s Manual 28 –Market Rule 1 Accounting located here.

Information about the monthly forward reserve auctions and assumptions can be found on the ISO’s web site located here.

10. Regulation Market

Regulation, or Automatic Generation Control (AGC), is necessary to balance supply levels against second-to-second variations in demand. On October 1, 2005, the ISO implemented a new Regulation market featuring several modifications to the market design in place since March 2003. This market design replaced the existing day-ahead methodology for calculating the Regulation clearing price with a real-time pricing methodology. The new design also pays units providing regulation service a performance-based component. Finally, the new approach pays units any unit-specific out-of-merit or lost opportunity costs incurred by a generator while providing regulation service.

10.1 Monthly Average of Hourly Regulation Market Clearing Price, Last 13 Months



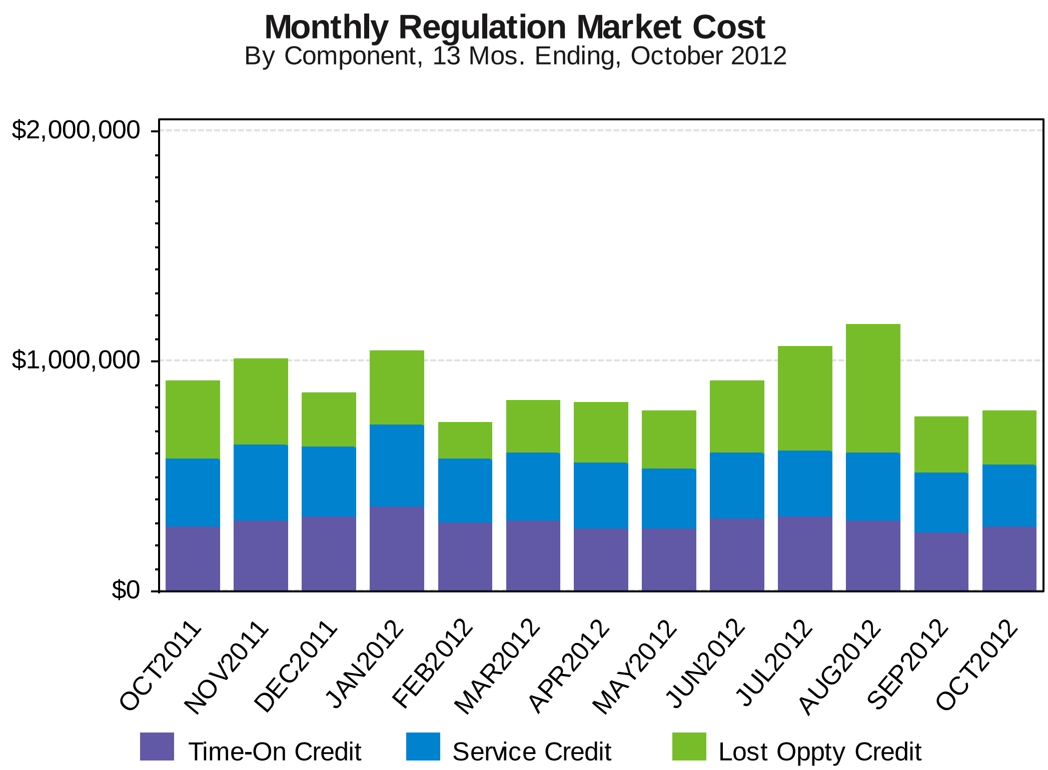
Value of monthly maximum and minimum clearing price also shown

10.2 Monthly Regulation Market Clearing Price Statistics, Last 13 Months

	On-Peak Clearing Price Statistics			
Month	Mean	Max	Min	StdDev
Oct-11	$6.53	$12.41	$4.91	$1.73
Nov-11	$6.73	$16.78	$4.26	$1.89
Dec-11	$6.67	$17.25	$5.00	$1.42
Jan-12	$6.90	$21.10	$1.49	$1.86
Feb-12	$6.31	$17.82	$5.01	$0.83
Mar-12	$6.24	$11.63	$0.00	$0.97
Apr-12	$6.83	$17.66	$4.71	$1.79
May-12	$6.26	$10.38	$4.75	$0.97
Jun-12	$7.46	$45.00	$0.93	$3.82
Jul-12	$7.33	$36.97	$3.93	$3.17
Aug-12	$7.13	$25.99	$4.45	$2.12
Sep-12	$6.93	$61.71	$4.64	$3.76
Oct-12	$6.70	$15.63	$4.50	$1.17

Month	Off-Peak Clearing Price Statistics			
	Mean	Max	Min	StdDev
Oct-11	$6.26	$12.08	$5.00	$1.23
Nov-11	$6.50	$13.19	$5.00	$1.23
Dec-11	$6.51	$10.75	$5.00	$1.01
Jan-12	$7.50	$22.02	$5.00	$2.53
Feb-12	$6.32	$10.16	$5.24	$0.54
Mar-12	$6.17	$11.00	$4.83	$0.83
Apr-12	$6.41	$70.33	$4.46	$3.79
May-12	$5.90	$20.08	$4.75	$1.31
Jun-12	$6.18	$17.74	$4.50	$1.36
Jul-12	$6.50	$17.38	$4.50	$1.23
Aug-12	$6.53	$16.40	$5.00	$1.49
Sep-12	$6.10	$11.85	$4.33	$0.86
Oct-12	$6.38	$8.66	$5.00	$0.67

10.3 Components of Monthly Regulation Market Cost, Last 13 Months



Month	Time on Regulation Credit	Lost Opportunity Cost Credit	Regulation Service Credit	Total Regulation Cost
Oct-11	$277,048	$335,685	$300,170	$912,902
Nov-11	$307,627	$371,419	$328,834	$1,007,880
Dec-11	$320,232	$232,899	$309,712	$862,843

Month	Time on Regulation Credit	Lost Opportunity Cost Credit	Regulation Service Credit	Total Regulation Cost
Jan-12	$369,994	$325,598	$351,059	$1,046,651
Feb-12	$295,428	$156,494	$285,015	$736,937
Mar-12	$308,166	$223,461	$295,157	$826,784
Apr-12	$276,138	$258,558	$285,390	$820,086
May-12	$267,623	$255,508	$261,491	$784,621
Jun-12	$316,588	$316,036	$284,819	$917,443
Jul-12	$321,428	$454,923	$286,150	$1,062,501
Aug-12	$309,461	$552,248	$294,593	$1,156,302
Sep-12	$256,450	$241,070	$260,821	$758,341
Oct-12	$280,666	$235,543	$272,530	$788,739

10.4 For More Information

The market rules governing the Regulation Market can be found in Section III.1.11.5 “Regulation” of the ISO’s Market Rule 1 located here.

The business rules and procedures for the Regulation Market can be found in the ISO’s Manual 11 – Market Operations located here:

Information about current regulation clearing prices can be found on the ISO’s web site here.

Selectable hourly historical regulation clearing prices can be found on the ISO’s web site here.

11. Marginal Loss Revenue Fund

The Marginal Loss Revenue Fund is allocated back to customers hourly in a pro-rata format based on customer share of the Pool's RT Adjusted Load Obligation. It consists of six components, as displayed in the following formula:

*Monthly Marginal Loss Revenue = (-1) * [Loss Revenue (DA+RT) + Energy Settlement (DA+RT) + RT Inadvertent Energy Cost + RT Emergency Energy Sales]*

The following table shows the contribution of each component to the Marginal Loss Revenue Fund and the fund total for last thirteen months.

11.1 Marginal Loss Revenue Fund by Month, 13 Mos. Ending October 2012

Month	Day-Ahead Energy Stlmnt	Real-Time Energy Stlmnt	Day-Ahead Loss Rev	Real-Time Loss Rev	Real-Time Inadvrt Energy	Real-Time Emergency Energy	Day-Ahead Marginal Loss Total	Real-Time Marginal Loss Total	Marg Loss Rev Fund Total
Oct-11	$5,307,838	$1,102,326	-$10,008,931	-$469,735	-$256,330	$0	$4,701,093	-$376,260	$4,324,833
Nov-11	$5,133,343	$880,821	-$9,538,871	-$579,693	$298,382	$0	$4,405,528	-$599,511	$3,806,017
Dec-11	$5,450,618	$1,783,376	-$10,191,890	-$415,149	-$437,719	$0	$4,741,272	-$930,508	$3,810,764
Jan-12	$6,416,116	$1,597,028	-$12,095,321	-$575,438	-$361,505	$0	$5,679,205	-$660,085	$5,019,121
Feb-12	$4,347,962	$677,959	-$8,153,657	-$241,976	$225,521	$0	$3,805,696	-$661,504	$3,144,191
Mar-12	$3,793,215	$437,016	-$7,231,314	-$418,023	$327,570	$0	$3,438,099	-$346,563	$3,091,536
Apr-12	$3,356,482	$1,178,540	-$6,262,096	-$499,423	$196,914	$0	$2,905,614	-$876,032	$2,029,583
May-12	$4,006,443	$775,760	-$7,707,599	-$610,479	$257,885	$0	$3,701,155	-$423,165	$3,277,990
Jun-12	$5,928,870	$651,942	-$11,247,930	-$881,963	-$159,364	$0	$5,319,060	$389,385	$5,708,444
Jul-12	$8,616,879	$140,354	-$16,301,035	-$536,709	$239,406	$0	$7,684,156	$156,949	$7,841,105
Aug-12	$7,150,202	$515,338	-$13,594,789	-$685,724	-$699,395	$0	$6,444,587	$869,782	$7,314,368
Sep-12	$4,735,695	$706,668	-$9,107,647	-$456,197	-$508,408	$0	$4,371,952	$257,937	$4,629,890
Oct-12	$4,605,139	$202,306	-$9,057,323	-$369,067	-$478,590	$0	$4,452,184	$645,351	$5,097,535

11.2 For More Information

Rules governing the calculation of the Marginal Loss Revenue Fund can be found in Section III.3.2.1 Accounting and Billing of the ISO's Market Rule 1 located here.

12. Forward Capacity Market

The Forward Capacity Market (FCM) is an auction based approach to meeting New England's forecasted capacity requirements for a future year. A portfolio of supply and demand resources is selected to provide this capacity through a competitive Forward Capacity Auction (FCA) process. Resources clearing in the FCA are paid the market clearing price for capacity and acquire a capacity supply obligation (CSO), a financially binding obligation to provide the cleared amount of capacity. FCM was implemented in June 2010, corresponding with the termination of the Forward Capacity Transition Period. For more information on the Forward Capacity Transition Period, see Section 12 of the Monthly Market Reports published prior to June 2011.

12.1 FCM Payments and Charges

Supply Credit is the total credit paid to customer resources for incurring a CSO and is the sum of the following types of CSO-related payments: Forward Capacity Auction (FCA) Credits, Bilateral Dollars, and Reconfiguration Auction (RA) Dollars. The following table shows total Supply Credit and its aforementioned components by Capacity Zone for the last thirteen months.

Month	Capacity Zone	FCA Credit	Bilateral Dollars	Reconfiguration Auction Dollars	Supply Credit
Oct-11	Rest-of-Pool	$111,654,434	$0	-$27,405	$111,627,029
Nov-11	Rest-of-Pool	$111,646,529	$0	-$27,704	$111,618,825
Dec-11	Rest-of-Pool	$111,646,518	$0	-$27,704	$111,618,814
Jan-12	Rest-of-Pool	$111,646,518	$0	-$27,704	$111,618,814
Feb-12	Rest-of-Pool	$111,646,518	$0	-$27,704	$111,618,814
Mar-12	Rest-of-Pool	$111,646,518	$0	-$27,704	$111,618,814
Apr-12	Rest-of-Pool	$111,646,529	$0	-$27,704	$111,618,825
May-12	Rest-of-Pool	$111,646,529	$0	-$27,704	$111,618,825
Jun-12	Rest-of-Pool	$79,362,327	$323,110	-$219,989	$79,465,448
Jun-12	Maine	$9,650,564	-$323,110	$209,032	$9,536,486
Jul-12	Rest-of-Pool	$79,340,545	$330,768	-$371,921	$79,299,392
Jul-12	Maine	$9,650,196	-$330,768	$272,735	$9,592,163
Aug-12	Rest-of-Pool	$79,351,746	$323,744	-$225,451	$79,450,039
Aug-12	Maine	$9,650,564	-$323,744	$214,405	$9,541,225
Sep-12	Rest-of-Pool	$79,321,446	$325,285	-$224,997	$79,421,734
Sep-12	Maine	$9,644,830	-$325,285	$213,765	$9,533,310
Oct-12	Rest-of-Pool	$79,664,936	$333,794	-$227,889	$79,770,840
Oct-12	Maine	$9,790,043	-$333,794	$216,658	$9,672,908

The initial supply credit paid for the CSO, as shown above, can be further adjusted based upon computed values for Peak Energy Rent (PER), the participation of the ISO in reconfiguration auctions, and actual resource performance. PER is a downward adjustment of FCM payments to reflect energy market revenues earned during high priced hours. In reconfiguration auctions, credits are reduced by the sale of excess CSO by the ISO or increased by the purchase of additional CSO. Resource availability during shortage events (generator and import resources) or performance during dispatch events and performance hours (demand resources) result in additional penalties and credits. The supply credit adjusted for reasons just stated results in the pool of money called the Net Regional Clearing Price (NRCP) Credit, which is the basis for charges for capacity allocated to real-time load obligation.

Additional credits may be earned by resources retained for reliability and their cost is allocated to Regional Network Load through the Open-Access Transmission Tariff rather than to Capacity Load Obligation (CLO).

The following table shows the various credit adjustments and total payments in the FCM made over the last 13 obligation months.

Month	Capacity Zone	CSO MW	Supply Credit (A)	PER Adjustment (B)	Excess DR Penalties (C)	NRCP Credit (D=A+B+C)	Reliability Credit (E)	Total Payment (F=D+E)
Oct-11	Rest-of-Pool	33,509	$111,627,029	-$267,586	$0	$111,359,443	$0	$111,359,443
Nov-11	Rest-of-Pool	33,507	$111,618,825	-$208,255	$0	$111,410,570	$0	$111,410,570
Dec-11	Rest-of-Pool	33,507	$111,618,814	$0	$0	$111,618,814	$0	$111,618,814
Jan-12	Rest-of-Pool	33,507	$111,618,814	$0	$0	$111,618,814	$0	$111,618,814
Feb-12	Rest-of-Pool	33,507	$111,618,814	$0	$0	$111,618,814	$0	$111,618,814
Mar-12	Rest-of-Pool	33,507	$111,618,814	$0	$0	$111,618,814	$0	$111,618,814
Apr-12	Rest-of-Pool	33,507	$111,618,825	$0	$0	$111,618,825	$0	$111,618,825
May-12	Rest-of-Pool	33,507	$111,618,825	$0	$0	$111,618,825	$0	$111,618,825
Jun-12	Rest-of-Pool	29,271	$79,465,448	$0	$0	$79,465,448	$1,623,350	$81,088,798
Jun-12	Maine	3,558	$9,536,486	$0	-$33,140	$9,503,347	$0	$9,503,347
Jul-12	Rest-of-Pool	29,016	$79,299,392	$0	$0	$79,299,392	$1,623,350	$80,922,742
Jul-12	Maine	3,803	$9,592,163	$0	-$15,772	$9,576,391	$0	$9,576,391
Aug-12	Rest-of-Pool	29,247	$79,450,039	$0	$0	$79,450,039	$1,623,350	$81,073,389
Aug-12	Maine	3,576	$9,541,225	$0	$0	$9,541,225	$0	$9,541,225
Sep-12	Rest-of-Pool	29,229	$79,421,734	$0	$0	$79,421,734	$1,623,350	$81,045,084
Sep-12	Maine	3,580	$9,533,310	$0	-$45,065	$9,488,245	$0	$9,488,245
Oct-12	Rest-of-Pool	29,336	$79,770,840	$0	$0	$79,770,840	$1,623,350	$81,394,190
Oct-12	Maine	3,647	$9,672,908	$0	-$49,496	$9,623,411	$0	$9,623,411

For each month and Capacity Zone, Load Serving Entities (LSEs) have capacity requirements which are calculated as their share of the total CSO purchased, based on their contribution to the system peak load from the previous year. Customers pay for capacity based on CLO. A customer's CLO is equivalent to its capacity requirement, adjusted for any Hydro-Quebec Installed Capacity Credits (HQICC), self-supply MWs, and CLO bilateral contracts. CLO bilateral contracts provide a means of transferring a capacity load obligation between two customers. Note that any customer, not just LSEs, can take on or shed CLO through a CLO bilateral contract.

The Net Regional Clearing Price is the rate at which load pays for capacity. It is calculated as:

*NRCP ($/kW-month) = NRCP Credit / (CLO MW * 1000)*

Where: *CLO MW = CSO MW – Self Supply MW – Excess RTEG MW*

Excess RTEG MW is composed of the CSO MW of Real Time Emergency Generation purchased in the Forward Capacity Auction in excess of 600 MW.

Charges are calculated as the product of a customer's CLO and the NRCP.

The following table provides details on aggregate FCM charges to load.

Month	CSO MW (A)	CLO Bilat MW	HQICC MW (B)	Excess RTEG MW (C)	Self Supply MW (D)	Capacity Req MW (E=A+B-C)	Peak Contrib MW	CLO MW (F=A-C-D)	Net Regional Clearing Price ($/kW-month)	Capacity Load Obligation Charge
Oct-11	33,509	2,193	911	67	1,696	34,353	26,701	31,747	$3.507753	$111,359,443
Nov-11	33,507	2,157	911	67	1,696	34,351	26,701	31,744	$3.509615	$111,410,570
Dec-11	33,507	2,186	911	0	1,696	34,418	26,701	31,811	$3.508758	$111,618,814
Jan-12	33,507	2,194	911	0	1,696	34,418	26,701	31,811	$3.508758	$111,618,814
Feb-12	33,507	2,186	911	0	1,696	34,418	26,701	31,811	$3.508758	$111,618,814
Mar-12	33,507	1,569	911	0	1,696	34,418	26,701	31,811	$3.508758	$111,618,814
Apr-12	33,507	821	911	67	1,696	34,351	26,701	31,744	$3.516176	$111,618,825
May-12	33,507	821	911	67	1,696	34,351	26,701	31,744	$3.516176	$111,618,825
Jun-12	32,828	891	977	0	1,928	33,805	27,312	30,900	$2.880325	$89,115,960
Jul-12	32,819	641	977	0	1,928	33,796	27,312	30,891	$2.877623	$89,308,658
Aug-12	32,824	641	977	0	1,928	33,801	27,312	30,895	$2.880404	$89,147,816
Sep-12	32,809	641	977	0	1,928	33,786	27,312	30,881	$2.880585	$89,088,521
Oct-12	32,983	641	977	0	1,928	33,960	27,312	31,055	$2.880173	$89,596,894

The calculations below describe how the Capacity Requirement and the Capacity Load Obligations are calculated for each Capacity Zone.

Capacity Requirement $_{\text{Capacity Zone}}$ = Peak Contribution MW $_{\text{Capacity Zone}}$ / Peak Contribution $_{\text{Pool}}$ * CSO $_{\text{Pool}}$ * (-1)

CLO $_{\text{Capacity Zone}}$ = Capacity Requirement $_{\text{Capacity Zone}}$ - HQICC MW $_{\text{Capacity Zone}}$ - CLO Self-Supply MW $_{\text{Capacity Zone}}$

There are two sides to a self-supply agreement – the generator supplying the MW and the entity using the MW to reduce its capacity requirement. During the 2012/2013 commitment period, with multiple capacity zones, a generator in Maine can have self-supply designations in both the Rest-of-Pool (ROP) and Maine. The NRCP is the per MW cost of capacity in a capacity zone. Self-supply MW used in the NRCP calculation are based on where the generator supplying the MWs resides and is presented in that manner below.

The following table provides details on FCM charges to load at the Capacity Zone level.

Month	Capacity Zone	CSO MW	HQICC MW	Self Supply MW	Capacity Req MW	Peak Contrib MW	CLO MW	Net Regional Clearing Price ($/kW-month)	Capacity Load Obligation Charge
Jun-12	Rest-of-Pool	29,271	977	1,919	31,436	25,400	28,534	$2.893540	$82,565,052
Jun-12	Maine	3,558	0	9	2,370	1,913	2,366	$2.769128	$6,550,908

Month	Capacity Zone	CSO MW	HQICC MW	Self Supply MW	Capacity Req MW	Peak Contrib MW	CLO MW	Net Regional Clearing Price ($/kW-month)	Capacity Load Obligation Charge
Jul-12	Rest-of-Pool	29,016	977	1,919	31,427	25,400	28,526	$2.914321	$83,132,684
Jul-12	Maine	3,803	0	9	2,369	1,913	2,365	$2.611362	$6,175,974
Aug-12	Rest-of-Pool	29,247	977	1,919	31,431	25,400	28,530	$2.895441	$82,607,045
Aug-12	Maine	3,576	0	9	2,369	1,913	2,365	$2.765215	$6,540,770
Sep-12	Rest-of-Pool	29,229	977	1,919	31,418	25,400	28,517	$2.896238	$82,590,674
Sep-12	Maine	3,580	0	9	2,368	1,913	2,364	$2.748251	$6,497,847
Oct-12	Rest-of-Pool	29,336	977	1,919	31,580	25,400	28,678	$2.897395	$83,092,751
Oct-12	Maine	3,647	0	9	2,381	1,913	2,377	$2.736787	$6,504,143

12.2 Capacity Transfer Rights (CTRs)

CTRs are a mechanism to distribute excess revenue that results from differences in payment rates between Capacity Zones; a CTR fund will be calculated for each constrained capacity zone. There are two types of CTRs: Specifically Allocated CTRs (defined in Market Rule 1 and always paid), and Residual CTRs (remaining funds or shortfall of funds after Specifically Allocated CTRs are paid). Residual CTRs will be allocated to the load serving entities with CLO on the import-constrained side of the interface. For the 2012/2013 Capacity Commitment Period (CCP), Maine is the export-constrained Capacity Zone, while Rest of Pool is on the import-constrained side of the interface. The Capacity Load Obligation Charge above can change depending on the CTRs associated with the Capacity Zone. The Capacity Transfer Rights Fund consists of the following:

- Pool Planned Unit CTRs for certain municipal utilities
- Maine Export Interface CTRs for Casco Bay
- Provisions for Transmission Upgrade CTRs

The following table provides detail, by month and capacity zone, of the Capacity Transfer Rights Dollars, the Specifically Allocated CTR MW and Dollars, along with the Residual CTR MW and Dollars.

Month	Export-constrained Capacity Zone (Charged)	Import-constrained Capacity Zone (Paid)	CTR Fund Dollars	Specifically Allocated CTR MW	Specifically Allocated CTR Dollars	Residual CTR MW	Residual CTR Dollars
Jun-12	Maine	Rest-of-Pool	$147,165.65	329.95	$23,096.38	-28,529.32	$124,069.27
Jul-12	Maine	Rest-of-Pool	$432,875.33	329.95	$23,096.38	-28,520.63	$409,778.95
Aug-12	Maine	Rest-of-Pool	$156,551.60	329.94	$23,095.71	-28,525.10	$133,455.89
Sep-12	Maine	Rest-of-Pool	$178,542.15	329.94	$23,095.71	-28,511.60	$155,446.44
Oct-12	Maine	Rest-of-Pool	$202,642.79	329.97	$23,097.89	-28,673.46	$179,544.90

12.3 PER Adjustment

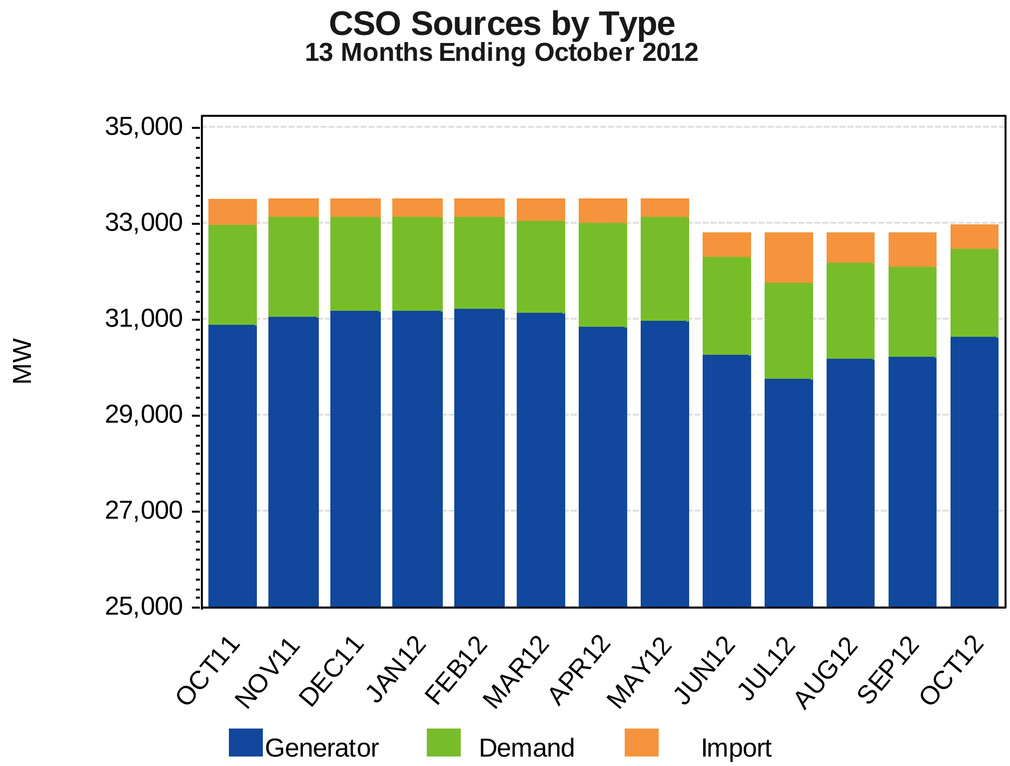
As stated above, PER is a payment adjustment made to reflect revenues earned by resources during high priced hours in the Energy markets. Generation and Import resources with a CSO are subject to PER adjustments (excluding self-supply CSO MWs). Demand resources are not subject to PER adjustments.

The following table provides detail, by month and capacity zone, of the CSO subject to PER, the rate at which these CSO are charged, and the total PER adjustment. It is important to note that individual resources are subject to an overall PER cap. Therefore, the product of the CSO and the rate in the table below will not necessarily equal the total PER adjustment.

Month	Capacity Zone	PER CSO MW	Average PER ($/kW-month)	Total PER Adjustment
Oct-11	Rest-of-Pool	29,734	0.009	$267,586
Nov-11	Rest-of-Pool	29,752	0.007	$208,255
Dec-11	Rest-of-Pool	29,901	0.000	$0
Jan-12	Rest-of-Pool	29,874	0.000	$0
Feb-12	Rest-of-Pool	29,913	0.000	$0
Mar-12	Rest-of-Pool	29,920	0.000	$0
Apr-12	Rest-of-Pool	29,681	0.000	$0
May-12	Rest-of-Pool	29,679	0.000	$0
Jun-12	Maine	3,006	0.000	$0
Jun-12	Rest-of-Pool	25,915	0.000	$0
Jul-12	Maine	3,257	0.000	$0
Jul-12	Rest-of-Pool	25,665	0.000	$0
Aug-12	Maine	3,030	0.000	$0
Aug-12	Rest-of-Pool	25,926	0.000	$0
Sep-12	Maine	3,031	0.000	$0
Sep-12	Rest-of-Pool	25,980	0.000	$0
Oct-12	Maine	3,093	0.000	$0
Oct-12	Rest-of-Pool	26,145	0.000	$0

12.4 Sources of Capacity

The following graph shows, in MW, the amount of capacity procured by type in New England for each of the last 13 months. The subsequent table displays the data underlying the graph.



Month	Demand Resource MW	Generation MW	Import MW	Total MW
Oct-11	2,103	30,889	517	33,509
Nov-11	2,082	31,057	368	33,507
Dec-11	1,943	31,196	368	33,507
Jan-12	1,961	31,179	368	33,507
Feb-12	1,922	31,218	368	33,507
Mar-12	1,914	31,154	439	33,507
Apr-12	2,154	30,861	492	33,507
May-12	2,158	30,981	368	33,507
Jun-12	2,012	30,275	541	32,828
Jul-12	2,003	29,764	1,052	32,819
Aug-12	1,977	30,188	658	32,824
Sep-12	1,899	30,203	707	32,809
Oct-12	1,846	30,630	507	32,983

12.5 Capacity Imports

The following table shows the monthly CSO MW resulting from imports for each of the last 13 months.

Month	Capacity Zone	NY AC Ties	New Brunswick	HQ Phase I/II	HQ Highgate	Total
Oct-11	Rest-of-Pool	247	0	70	200	517
Nov-11	Rest-of-Pool	98	0	70	200	368
Dec-11	Rest-of-Pool	98	0	70	200	368
Jan-12	Rest-of-Pool	98	0	70	200	368
Feb-12	Rest-of-Pool	98	0	70	200	368
Mar-12	Rest-of-Pool	169	0	70	200	439
Apr-12	Rest-of-Pool	222	0	70	200	492
May-12	Rest-of-Pool	98	0	70	200	368
Jun-12	Rest-of-Pool	104	0	244	193	541
Jun-12	Maine	0	0	0	0	0
Jul-12	Rest-of-Pool	185	0	423	193	801
Jul-12	Maine	0	251	0	0	251
Aug-12	Rest-of-Pool	104	0	361	193	658
Aug-12	Maine	0	0	0	0	0
Sep-12	Rest-of-Pool	104	0	410	193	707
Sep-12	Maine	0	0	0	0	0
Oct-12	Rest-of-Pool	104	0	210	193	507
Oct-12	Maine	0	0	0	0	0

12.6 Performance

All capacity resources with a CSO are subject to evaluation during each obligation month of a commitment period to ensure they can deliver the capacity for which they are paid. Generation and Import resources are evaluated for performance during shortage events. Demand resources are evaluated during dispatch events and performance hours.

12.6.1 Generation and Import Resource Availability

A shortage event reflects a shortage of operating reserves, as defined by 30 or more consecutive minutes of system Reserve Constraint Penalty Factor activation. Available MWs from Generation and Import resources are measured during shortage events, and availability scores are calculated based on this performance. Available MWs can be adjusted by Supplemental Availability Bilateral (SAB) agreements as well as exempt outage MWs. A resource's availability score is then used to compute the availability penalty associated with the shortage event.

Month	Hours with Shortage Events	Total Duration of Shortage Events (Hours)	Resource Type	SAB MW (Sold)	SAB MW (purchased)	Shortage Event Penalty
Oct-11	0	0.00	Generator	0	0	$0
Oct-11	0	0.00	Import	0	0	$0

Month	Hours with Shortage Events	Total Duration of Shortage Events (Hours)	Resource Type	SAB MW (Sold)	SAB MW (purchased)	Shortage Event Penalty
Nov-11	0	0.00	Generator	0	0	$0
Nov-11	0	0.00	Import	0	0	$0
Dec-11	0	0.00	Generator	0	0	$0
Dec-11	0	0.00	Import	0	0	$0
Jan-12	0	0.00	Generator	0	0	$0
Jan-12	0	0.00	Import	0	0	$0
Feb-12	0	0.00	Generator	0	0	$0
Feb-12	0	0.00	Import	0	0	$0
Mar-12	0	0.00	Generator	0	0	$0
Mar-12	0	0.00	Import	0	0	$0
Apr-12	0	0.00	Generator	0	0	$0
Apr-12	0	0.00	Import	0	0	$0
May-12	0	0.00	Generator	0	0	$0
May-12	0	0.00	Import	0	0	$0
Jun-12	0	0.00	Generator	0	0	$0
Jun-12	0	0.00	Import	0	0	$0
Jul-12	0	0.00	Generator	0	0	$0
Jul-12	0	0.00	Import	0	0	$0
Aug-12	0	0.00	Generator	0	0	$0
Aug-12	0	0.00	Import	0	0	$0
Sep-12	0	0.00	Generator	0	0	$0
Sep-12	0	0.00	Import	0	0	$0
Oct-12	0	0.00	Generator	0	0	$0
Oct-12	0	0.00	Import	0	0	$0

12.6.2 Demand Resource Performance

Demand Resources are collections of assets which reduce their consumption of energy in order to provide capacity to the system. There are four types of Demand Resources: Real-Time Demand Response resources (RTDR), Real-Time Emergency Generation resources (RTEG), On-Peak resources, and Seasonal Peak resources. RTDR and RTEG are active demand resources, and are required to respond to dispatch instructions from ISO-NE. During these dispatch events, active resources are expected to curtail their energy consumption for the system by an amount equal to that requested by ISO-NE. On-Peak and Seasonal Peak resources, on the other hand, are passive demand resources, and do not receive dispatch instructions from ISO-NE. Instead, these resources curtail their electricity use at set times throughout the year. On-Peak resources must reduce consumption during summer peak hours (non-holiday weekdays, 1:00 p.m. to 5:00 p.m., during June, July, and August) and winter peak hours (non-holiday weekdays, 5:00 p.m. to 7:00 p.m., during December and January). Seasonal Peak resources must reduce consumption during the summer months of June, July, and August and during the winter months of December and January in hours on non-holiday weekdays when the Real-Time System Hourly Load is equal to or greater than 90% of the most recent "50/50" System Peak Load Forecast.

Demand Resource performance is measured during hours with dispatch events for active resources, and during performance hours for passive resources. Resources with a capacity value less than their CSO will be assessed a penalty, while those with a capacity value greater than their CSO are eligible for a performance incentive. In the absence of a performance event during performance months, a resource's capacity value and resulting variance will be based on its effective audit result; and in non-performance months, a resource's capacity value and resulting variance will be based upon its Seasonal Demand Reduction Value.

The following table displays a pool-level summary of Demand Resource performance by type for the past 13 months.

Month	DR Type	Performance Hours	CSO MW	Capacity Value (MW)	Negative Capacity Variance (MW)	Positive Capacity Variance (MW)	Performance Penalty ($)	Performance Incentive ($)
Oct-11	ON_PEAK	0	614.68	960.74	-3.52	349.58	-$12,408	$126,088
Oct-11	REAL_TIME	0	750.30	802.27	-25.53	77.40	-$79,641	$26,327
Oct-11	REAL_TIME_EG	0	479.03	473.51	-28.85	23.33	-$71,166	$6,278
Oct-11	SEASONAL_PEAK	0	259.38	282.91	-1.25	24.79	-$3,911	$8,433
Nov-11	ON_PEAK	0	614.82	960.74	-3.31	349.23	-$11,747	$104,350
Nov-11	REAL_TIME	0	732.01	801.52	-17.76	87.16	-$55,378	$24,559
Nov-11	REAL_TIME_EG	0	476.06	473.51	-28.65	26.10	-$70,675	$5,816
Nov-11	SEASONAL_PEAK	0	259.38	282.91	-1.25	24.79	-$3,911	$6,986
Dec-11	ON_PEAK	42	613.14	1,125.29	-2.57	514.72	-$8,359	$351,786
Dec-11	REAL_TIME	3	631.85	555.24	-113.60	36.95	-$354,325	$21,947
Dec-11	REAL_TIME_EG	0	438.59	431.00	-42.47	34.88	-$104,783	$16,386
Dec-11	SEASONAL_PEAK	0	259.38	405.60	-3.76	149.98	-$11,734	$89,082
Jan-12	ON_PEAK	42	616.98	1,180.67	-2.11	565.80	-$6,575	$503,209
Jan-12	REAL_TIME	0	648.62	577.88	-146.06	75.28	-$455,552	$58,748
Jan-12	REAL_TIME_EG	0	435.66	340.58	-107.34	12.26	-$264,800	$7,567
Jan-12	SEASONAL_PEAK	7	259.38	461.06	0.00	201.69	$0	$157,403
Feb-12	ON_PEAK	0	616.90	1,154.95	-2.42	540.47	-$7,693	$320,155
Feb-12	REAL_TIME	0	625.71	572.41	-93.50	40.16	-$291,623	$20,780
Feb-12	REAL_TIME_EG	0	419.87	385.81	-54.82	20.75	-$135,231	$8,493
Feb-12	SEASONAL_PEAK	0	259.38	433.33	-1.88	175.84	-$5,867	$90,985
Mar-12	ON_PEAK	0	616.15	1,154.95	-2.21	540.55	-$7,049	$300,013
Mar-12	REAL_TIME	0	616.20	572.41	-84.91	41.08	-$264,837	$19,918
Mar-12	REAL_TIME_EG	0	422.70	385.81	-54.37	17.48	-$134,136	$6,704
Mar-12	SEASONAL_PEAK	0	259.38	433.33	-1.88	175.84	-$5,867	$85,255
Apr-12	ON_PEAK	0	616.02	960.78	-2.96	347.72	-$10,637	$100,390
Apr-12	REAL_TIME	0	787.55	799.10	-12.54	23.99	-$39,125	$6,531
Apr-12	REAL_TIME_EG	0	491.07	473.51	-24.97	7.41	-$61,594	$1,596
Apr-12	SEASONAL_PEAK	0	259.38	282.91	-1.25	24.79	-$3,911	$6,749
May-12	ON_PEAK	0	615.23	960.78	-2.17	347.72	-$8,173	$102,506
May-12	REAL_TIME	0	792.46	808.16	-14.67	30.27	-$45,743	$8,413
May-12	REAL_TIME_EG	0	491.16	473.51	-24.97	7.32	-$61,594	$1,610

Month	DR Type	Performance Hours	CSO MW	Capacity Value (MW)	Negative Capacity Variance (MW)	Positive Capacity Variance (MW)	Performance Penalty ($)	Performance Incentive ($)
May-12	SEASONAL_PEAK	0	259.38	282.91	-1.25	24.79	-$3,911	$6,892
Jun-12	ON_PEAK	84	723.02	861.13	-6.38	144.49	-$16,487	$69,240
Jun-12	REAL_TIME	0	642.73	682.41	-36.50	76.18	-$92,919	$35,094
Jun-12	REAL_TIME_EG	0	410.07	403.96	-28.63	22.51	-$68,781	$13,011
Jun-12	SEASONAL_PEAK	22	236.22	305.06	0.00	68.84	$0	$27,702
Jul-12	ON_PEAK	84	729.16	853.07	-13.96	137.88	-$37,467	$295,194
Jul-12	REAL_TIME	0	631.53	544.87	-125.64	38.97	-$317,616	$85,937
Jul-12	REAL_TIME_EG	0	393.03	331.22	-79.77	17.96	-$192,071	$33,505
Jul-12	SEASONAL_PEAK	23	248.89	309.65	-0.86	61.62	-$2,185	$118,931
Aug-12	ON_PEAK	92	729.21	827.78	-41.12	139.69	-$107,911	$313,502
Aug-12	REAL_TIME	0	607.67	549.83	-101.99	44.16	-$258,441	$82,750
Aug-12	REAL_TIME_EG	0	391.65	330.18	-76.29	14.81	-$183,670	$27,933
Aug-12	SEASONAL_PEAK	8	248.89	310.68	-0.86	62.65	-$2,185	$128,021
Sep-12	ON_PEAK	0	726.83	857.98	-17.80	148.95	-$46,226	$158,058
Sep-12	REAL_TIME	0	562.70	538.14	-51.05	26.49	-$127,841	$24,738
Sep-12	REAL_TIME_EG	0	363.50	330.84	-53.04	20.38	-$127,899	$18,727
Sep-12	SEASONAL_PEAK	0	246.43	308.50	-0.57	62.64	-$1,455	$56,833
Oct-12	ON_PEAK	0	725.35	857.98	-16.32	148.95	-$42,496	$114,944
Oct-12	REAL_TIME	0	505.42	552.23	-42.94	89.75	-$107,254	$59,333
Oct-12	REAL_TIME_EG	0	369.15	330.84	-49.63	11.32	-$119,617	$7,131
Oct-12	SEASONAL_PEAK	0	246.43	308.50	-0.57	62.64	-$1,455	$39,919

12.7 For More Information

Detailed information on the FCM, including information on the qualification process, auction results, and FERC filings and orders can be found here.

Detailed information about FCM Charge calculation summaries can be found here.

13. Energy Market Payments to Demand Assets

Energy Market payments to demand assets are administered through the Day-Ahead Load Response Program (DALRP), Real-Time Price-Response Program , and, commencing in June 2012, through the Transitional Demand Response (TDR) program.

13.1 DALRP and Real-Time Price-Response Program

The two programs active prior to June 2012 are described below:

- Day-Ahead Load-Response Program (DALRP) allows Market Participants with registered Load Response Program assets belonging to a Real-Time Demand Resource (RTDR) or the Real-Time Price Response Program to offer price-sensitive interruptions into the Day-Ahead Energy Market. If an offer is accepted (clears), the Market Participants are paid the day-ahead LMP and are obligated to reduce load in real-time by the amount cleared day-ahead. The participants then are charged or credited at the real-time LMP for any deviations in curtailment occurring during real-time from their cleared interruptions.

- Real-Time Price-Response Program is a voluntary load reduction program. Market Participants are eligible for payment when the forecast hourly real-time LMP is greater than or equal to $100/MWh and the ISO has transmitted instructions that the eligibility period is open. Market Participants are paid the higher of $100/MWh or the real-time LMP.

The data relating to these programs is reported here on a one month lag from the report month, due to the timeline for settling this particular market.

The following table displays day-ahead cleared megawatt-hours, interruptions, and payments for assets belonging to RTDRs or participating in the price-response program and which have cleared offers in the DALRP. DALRP payments represent the sum of any payments made for cleared DA megawatts plus any additional payments or penalties for deviations from this cleared amount. The Settlement Status column indicates whether data for the month have already gone through the 90 day resettlement Data Reconciliation Process ("DRP"), or are still in the initial phase of settlement and therefore subject to change ("Initial").

	RTDR Assets			Price Response Program			
Latest Available Month	Day-Ahead Cleared (MWh)	Actual Real-Time Interruptions (MWh)	DALRP Payments	Day-Ahead Cleared (MWh)	Actual Real-Time Interruptions (MWh)	DALRP Payments	Stlmnt Status
Sep-11	6,072.90	4,840.14	$260,715	0.00	0.00	$0	DRP
Oct-11	7,253.00	9,373.73	$490,760	0.00	0.00	$0	DRP
Nov-11	317.40	1,080.22	$61,207	0.00	0.00	$0	DRP
Dec-11	799.20	841.36	$55,039	0.00	0.00	$0	DRP
Jan-12	1,812.30	2,293.42	$173,703	0.00	0.00	$0	DRP
Feb-12	70.70	116.68	$5,982	0.20	1.22	$53	DRP
Mar-12	170.30	356.27	$18,316	0.00	0.00	$0	DRP
Apr-12	1,383.80	5,229.40	$174,185	0.00	0.00	$0	DRP
May-12	1,471.70	4,138.00	$154,807	0.00	0.00	$0	DRP

The table below displays real-time interruptions and payments for assets participating in the Real-Time Price Response program during real-time price events. The MWs and payments displayed in this table are attributable to the Price event only, and do not include any concurrent interruptions from the DALRP.

Latest Available Month	Price Response Program		
	Real-Time Interruptions (MWh)	Real-Time Program Payments	Stlmnt Status
Sep-11	50.85	$5,089	DRP
Oct-11	0.00	$0	DRP
Nov-11	54.71	$5,746	DRP
Dec-11	190.06	$19,006	DRP
Jan-12	178.28	$18,380	DRP
Feb-12	0.00	$0	DRP
Mar-12	0.00	$0	DRP
Apr-12	148.00	$14,800	DRP
May-12	151.87	$18,587	DRP

13.2 Transitional Demand Response

The Transitional Demand Response (TDR) program represents, in the aggregate, agreements between wholesale providers and retail customers to encourage reduction of their electricity consumption during periods of peak demand. Transitional Demand Response in New England is administered post the Day-Ahead Energy Market clearing and the scheduling of demand reductions by Market Participants in real-time based upon system conditions.

13.2.1 Transitional Demand Response Payments

- A Real-Time Demand Response Asset with an offer that clears in the post Day-Ahead Energy Market clearing will receive a payment for its Day-Ahead Demand Reduction Obligation at the applicable Day-Ahead Zonal Locational Marginal Price (LMP) and will be paid or charged for the difference between its Real-Time Demand Reduction Obligation and its Day-Ahead Demand Reduction Obligation in Real-Time at the applicable Real-Time Zonal LMP.

- A Real-Time Demand Response Asset with an offer that does not clear in the post Day-Ahead Energy Market clearing will be eligible to receive a payment for its Real-Time Demand Reduction Obligation at the applicable Real-Time Zonal LMP when the hourly provisional Real-Time Zonal LMP is greater than or equal to the its Demand Reduction Offer price.

- A Real-Time Demand Response Asset or Real-Time Emergency Generation Asset that is associated to a Demand Resource in the Forward Capacity Market will receive a payment at the applicable Real-Time Zonal LMP, for its demand reduction, when the Demand Resource is dispatched or audited pursuant to Section III.13 of Market Rule 1.

13.2.2 Transitional Demand Response Charges

- The total credits associated with Transitional Demand Response are allocated on an hourly basis proportionally to Market Participants with Real-Time Load Obligations on a system-wide basis, excluding Real-Time Load Obligations incurred at all External Nodes or incurred by Dispatchable Asset Related Demand Postured by the ISO.

The following table displays Day-Ahead Demand Reduction Obligation megawatt-hours MWh (Day-Ahead Cleared MWh, plus average avoided peak distribution losses of 6.5%), Day-Ahead payments, Real-Time Demand Reduction MWh, FCM Audit Demand Reduction MWh, Real-Time Demand Reduction Deviation MWh, Real-Time Payment Dollars, Total Payment (sum of total Day-Ahead and Real-Time Payments), average Pool Demand Response Charge Allocation MWh, and the Charge per MWh. The relationship between Day-Ahead Demand Reduction Obligation MWh and RT Demand Reduction MWh can be described as:

*DA Demand Reduction Obligation MWh = Average Avoided Peak Distribution Losses (1.065) * RT Demand Reduction MWh – RT Demand Reduction Deviation MWh*

Month	DA Demand Reduction Obligation MWh	DA Payment Dollars	RT Demand Reduction MWh	RT Demand Reduction Deviation MWh	RT Payment Dollars	FCM Audit Demand Reduction MWh	FCM Audit Demand Reduction Dollars	Total Payment (Charge) Dollars	Average Pool Demand Response Charge Allocation MWh	Charge per MWh
Jun-12	2,086	$163,906	2,516	590	$67,425	173	$23,498	$254,829	17,087	$0.02
Jul-12	2,885	$187,068	3,112	443	$38,811	2,500	$142,222	$368,102	19,739	$0.03
Aug-12	4,166	$207,729	4,150	253	$64,301	93	$4,796	$276,825	19,514	$0.02
Sep-12	3,659	$160,978	3,558	100	$3,104	13	$2,488	$166,570	16,013	$0.02
Oct-12	3,216	$124,922	3,884	920	$38,338	0	$0	$163,260	14,609	$0.02

13.3 For More Information:

Rules governing the calculation of the Transitional Demand Response can be found in Section III.13 Market Rule 1 and Section III, Appendix E located here.

14. Document History

Date	Version	Description
11/13/2012	Original Posting	