Monthly Market Operations Report
August 2011

ISO New England Inc.
Market Analysis and Settlements
September 20, 2011

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 at: http://www.iso-ne.com/markets/mkt_anlys_rpts/wkly_mktops_rpts/index.html.

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 at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/index.html 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 at http://www.iso-ne.com/markets/mkt_anlys_rpts/qtrly_mktops_rpts/index.html.

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 can not be included here. Additional information can be found on the ISO's web site at http://www.iso-ne.com/markets/mkt_anlys_rpts/index.html.

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3. Monthly Summary

Day-ahead and real-time LMPs at the New England Hub averaged $43.85/MWh and $43.92/MWh, respectively, during August 2011. Day-ahead and real-time prices at the Hub and in the Load Zones averaged 19-25% lower than July 2011 averages. In the aggregate, August 2011 day-ahead and real-time LMPs were approximately 19% lower than during August 2010. Average natural gas prices were about 7% below the prior year's average prices, while residual fuel prices were up 38% over a year ago.

Overall, the average of the hourly real-time LMPs at the Hub and in the Load Zones ranged between equivalent to day-ahead LMPs in the Maine (ME) Load Zone to 1.3% higher than their day-ahead counterpart in the Western/Central Massachusetts (WCMA) Load Zone. In the Day-Ahead Market, Load Zone average LMPs ranged between 3.0% lower than the Hub average LMPs in the ME Load Zone to 2.0% higher than the Hub in the Connecticut (CT) Load Zone. Results were similar in the Real-Time Market, with average LMPs ranging from 3.2% lower than the Hub average LMPs in the ME Load Zone to 2.6% higher than the Hub in the CT Load Zone. Price differentials between on-peak and off-peak hours at the Hub and in the Load Zones ranged between 16% and 30% 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 August. In the Day-Ahead Energy Market, there were approximately 649,000 MWh of total exports and 1,277,000 MWh of imports, yielding a net import of approximately 628,000 MWh. In the Real-Time Energy Market, there were approximately 804,000 MWh of total exports and 1,386,000 MWh of imports, yielding a net import of approximately 581,000 MWh. This was about 450,000 MWh higher than a year ago.

The Monthly FTR Auction (August 2011) had 33 participants and the awarded value of FTRs in the auction totaled $820,000 . This represented an increase of $99,000 over the previous month and a decrease of about $727,000 from the prior year's monthly FTR auction. The allocation of FTR Auction Revenue for August 2011 resulted in $2.0 million awarded to eligible entities, with $161K allocated to Qualified Upgrade Awards.

The Marginal Loss Revenue Fund totaled $6.6 million for August, down $4.6 million from its July 2011 total.

Total Forward Reserve Credits to eligible assets of $1.3 million were reduced by $116,000 in Failure to Reserve Penalties and $0 in Failure to Activate Penalties during August 2011. The net Forward Reserve Payment of $1.2 million represented 86% of the maximum possible payment of $1.4 million. Real-Time Reserve Prices occurred in 20 separate hours during the month, and those yielded real-time payments to designated assets of $166,000 . These payments were reduced by Forward Reserve Energy Obligation Charges totaling $1,000 yielding a net compensation of $165,000 during the month.

Regulation Market Payments totaled $1.0 million during the month, a decrease of $274 K from the July 2011 value of $1.3 million.

In the Forward Capacity Market (FCM) for the month of August 2011, Forward Capacity payments were made to a total of 33,322 MW of capacity and totaled $103 million.

There are two programs through which load response assets can participate in the Energy Market. Total payments during July 2011 (the latest month available) totaled $2.1 million for interruptions associated with the Day Ahead Load Response Program and $28K for interruptions associated with the Real Time Price Response Program.

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, August 2011

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	$43.85	$43.92	$14.06	$0.00	$94.96	$335.89	82%	79%	100.2%	$11.06	$27.49	2.49
ME	$42.52	$42.51	$13.52	$0.00	$90.10	$323.91	79%	77%	100.0%	$10.13	$26.39	2.61
NH	$43.50	$43.63	$13.89	$0.00	$93.54	$332.47	81%	79%	100.3%	$10.88	$27.28	2.51
VT	$44.42	$44.49	$14.07	$0.00	$95.59	$342.42	83%	80%	100.2%	$11.24	$27.96	2.49
CT	$44.71	$45.04	$13.98	$0.00	$98.54	$346.43	83%	81%	100.7%	$11.75	$29.12	2.48
RI	$43.33	$43.47	$14.18	$0.00	$93.74	$330.06	81%	78%	100.3%	$10.78	$27.10	2.51
SEMA	$43.67	$43.89	$14.09	$0.00	$95.05	$335.40	82%	79%	100.5%	$11.06	$27.61	2.50
WCMA	$44.21	$44.80	$14.11	$0.00	$95.66	$339.02	83%	81%	101.3%	$11.21	$29.80	2.66
NEMA	$43.46	$43.69	$14.04	$0.00	$94.18	$333.45	81%	79%	100.5%	$10.94	$27.42	2.51
NB Ext	$40.67	$40.55	$13.05	$0.00	$87.42	$305.21	76%	73%	100%	$9.58	$25.11	2.62
NYN Ext	$44.39	$44.53	$13.90	$0.00	$96.58	$345.00	83%	80%	100%	$11.38	$28.03	2.46
HQ Ext	$42.64	$42.83	$13.85	$0.00	$91.71	$325.46	80%	77%	100%	$10.55	$26.68	2.53
HG Ext	$41.87	$42.34	$13.11	$0.00	$89.46	$323.89	78%	76%	101%	$10.22	$26.36	2.58
CSC Ext	$44.72	$45.58	$13.95	$0.00	$98.53	$350.15	84%	82%	102%	$11.76	$29.32	2.49
NNC Ext	$45.04	$45.27	$13.92	$0.00	$99.47	$351.44	84%	82%	101%	$11.87	$28.90	2.44

4.1.2 On-Peak Hours, August 2011

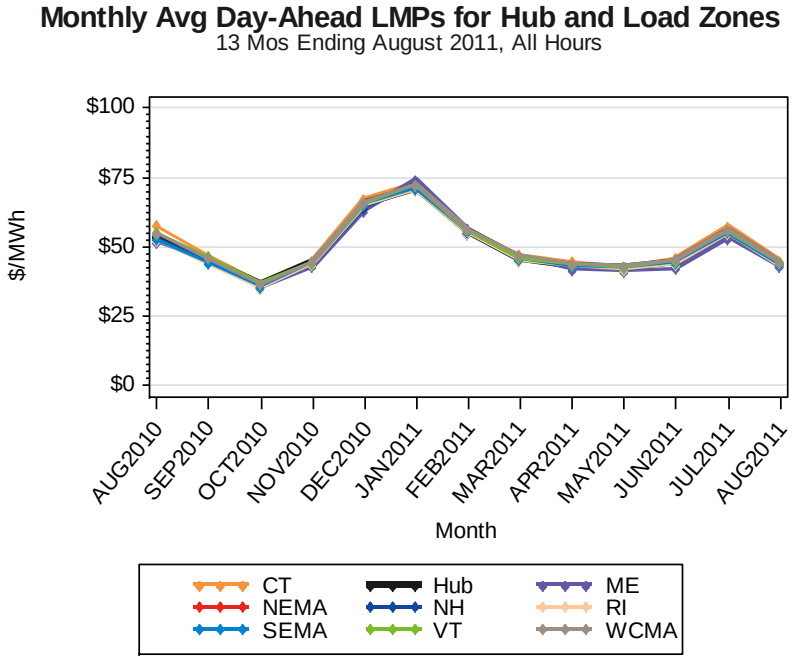
Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$49.30	$47.64	$32.39	$0.00	$94.96	$265.27	74%	68%	97%	$10.91	$24.25	2.22
ME	$47.36	$45.73	$31.26	$0.00	$90.10	$255.14	71%	65%	97%	$10.11	$23.01	2.28
NH	$48.87	$47.30	$31.79	$0.00	$93.54	$263.06	73%	67%	97%	$10.76	$24.04	2.23
VT	$49.96	$48.18	$32.09	$0.00	$95.59	$264.86	75%	68%	96%	$11.16	$24.52	2.20
CT	$50.58	$49.04	$32.55	$0.00	$98.54	$271.67	76%	70%	97%	$11.49	$25.25	2.20
RI	$48.58	$47.12	$32.42	$0.00	$93.74	$262.55	73%	67%	97%	$10.70	$23.98	2.24
SEMA	$49.14	$47.69	$32.34	$0.00	$95.05	$267.44	74%	68%	97%	$10.89	$24.43	2.24
WCMA	$49.75	$48.44	$32.59	$0.00	$95.66	$270.51	75%	69%	97%	$11.06	$25.13	2.27
NEMA	$48.85	$47.42	$32.01	$0.00	$94.18	$265.26	73%	67%	97%	$10.83	$24.23	2.24
NB Ext	$45.04	$43.48	$29.33	$0.00	$87.42	$250.09	68%	62%	97%	$9.87	$21.99	2.23
NYN Ext	$49.98	$48.30	$32.23	$0.00	$96.58	$262.06	75%	68%	97%	$11.26	$24.37	2.17
HQ Ext	$47.77	$46.35	$31.59	$0.00	$91.71	$258.13	72%	66%	97%	$10.50	$23.54	2.24
HG Ext	$46.64	$45.29	$29.40	$0.00	$89.46	$250.33	70%	64%	97%	$10.56	$23.27	2.20
CSC Ext	$50.56	$49.59	$32.61	$0.00	$98.53	$273.51	76%	70%	98%	$11.52	$25.39	2.20
NNC Ext	$50.96	$49.32	$32.62	$0.00	$99.47	$271.76	76%	70%	97%	$11.62	$25.22	2.17

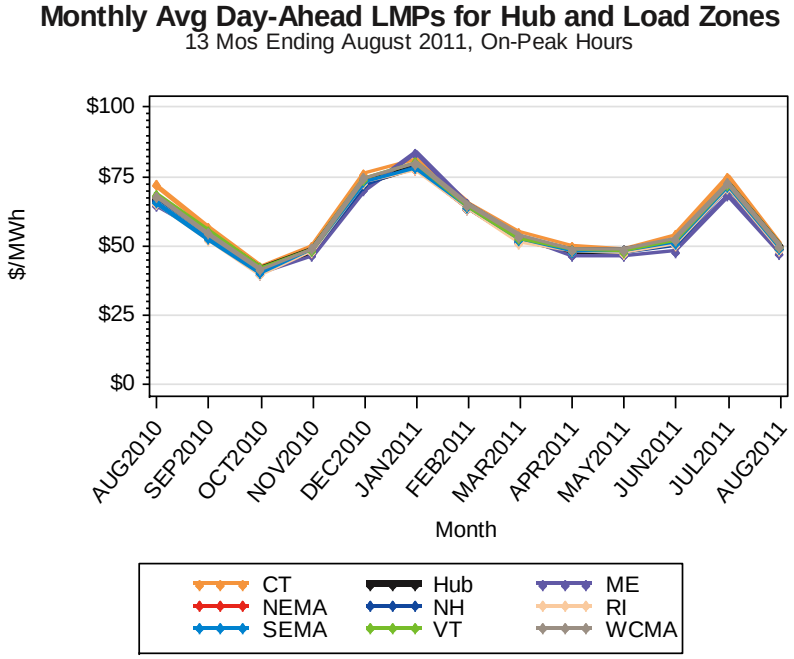
4.1.3 Off-Peak Hours, August 2011

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	$38.52	$40.27	$14.06	$0.00	$59.65	$335.89	92%	96%	105%	$8.26	$29.92	3.62
ME	$37.78	$39.36	$13.52	$0.00	$57.17	$323.91	90%	94%	104%	$7.60	$29.01	3.82
NH	$38.24	$40.03	$13.89	$0.00	$59.13	$332.47	92%	96%	105%	$8.08	$29.72	3.68
VT	$39.01	$40.88	$14.07	$0.00	$60.00	$342.42	93%	98%	105%	$8.31	$30.57	3.68
CT	$38.96	$41.13	$13.98	$0.00	$61.18	$346.43	93%	98%	106%	$8.79	$32.01	3.64
RI	$38.20	$39.90	$14.18	$0.00	$59.02	$330.06	91%	95%	104%	$8.06	$29.44	3.65
SEMA	$38.32	$40.16	$14.09	$0.00	$59.52	$335.40	92%	96%	105%	$8.25	$29.97	3.63
WCMA	$38.78	$41.24	$14.11	$0.00	$60.02	$339.02	93%	99%	106%	$8.34	$33.41	4.00
NEMA	$38.18	$40.04	$14.04	$0.00	$59.13	$333.45	91%	96%	105%	$8.13	$29.80	3.67
NB Ext	$36.40	$37.70	$13.05	$0.00	$53.68	$305.21	87%	90%	104%	$7.05	$27.55	3.91
NYN Ext	$38.93	$40.85	$13.90	$0.00	$60.71	$345.00	93%	98%	105%	$8.48	$30.79	3.63
HQ Ext	$37.61	$39.38	$13.85	$0.00	$57.79	$325.46	90%	94%	105%	$7.85	$29.04	3.70
HG Ext	$37.21	$39.45	$13.11	$0.00	$56.08	$323.89	89%	94%	106%	$7.32	$28.80	3.93
CSC Ext	$39.01	$41.66	$13.95	$0.00	$61.26	$350.15	93%	100%	107%	$8.83	$32.27	3.65
NNC Ext	$39.24	$41.30	$13.92	$0.00	$61.72	$351.44	94%	99%	105%	$8.88	$31.63	3.56

4.2 LMP Graphs, Day-Ahead Market, 13 Months Ending August 2011

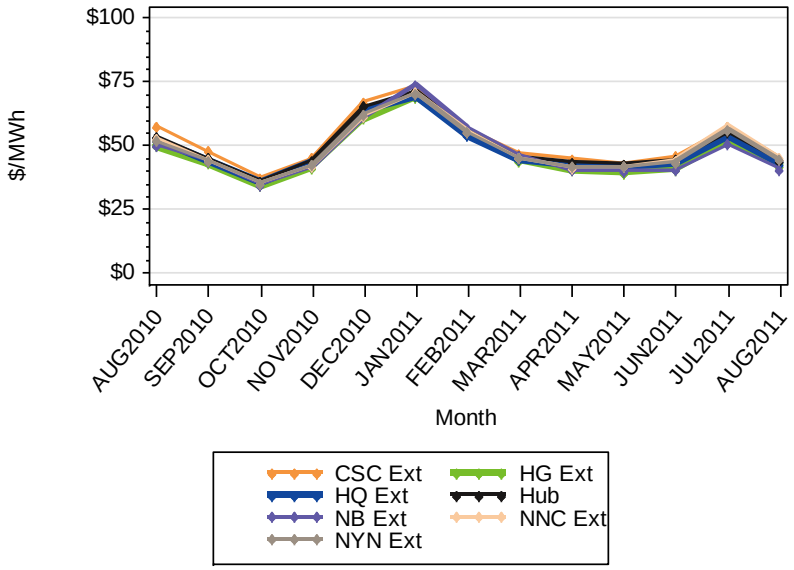
The following four graphs show the 13 month history of average hourly Day-Ahead LMPs for the Hub, Load Zones, and External Nodes on an overall and on-peak basis.





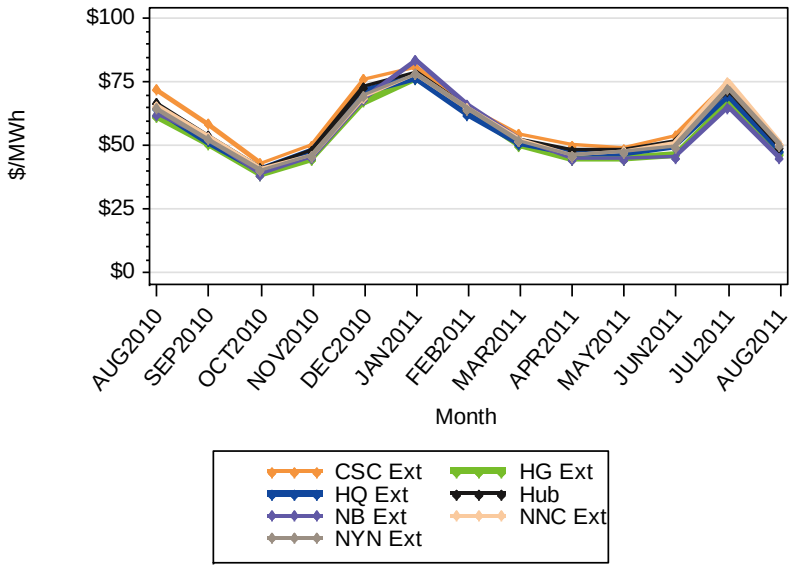
Monthly Avg Day-Ahead LMPs for Hub and External Nodes

13 Mos Ending August 2011, All Hours



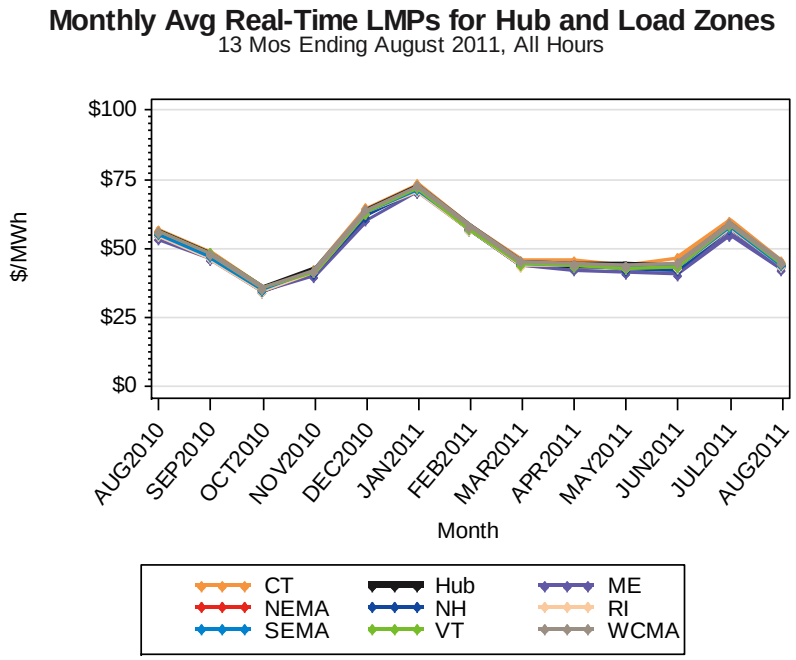
Monthly Avg Day-Ahead LMPs for Hub and External Nodes

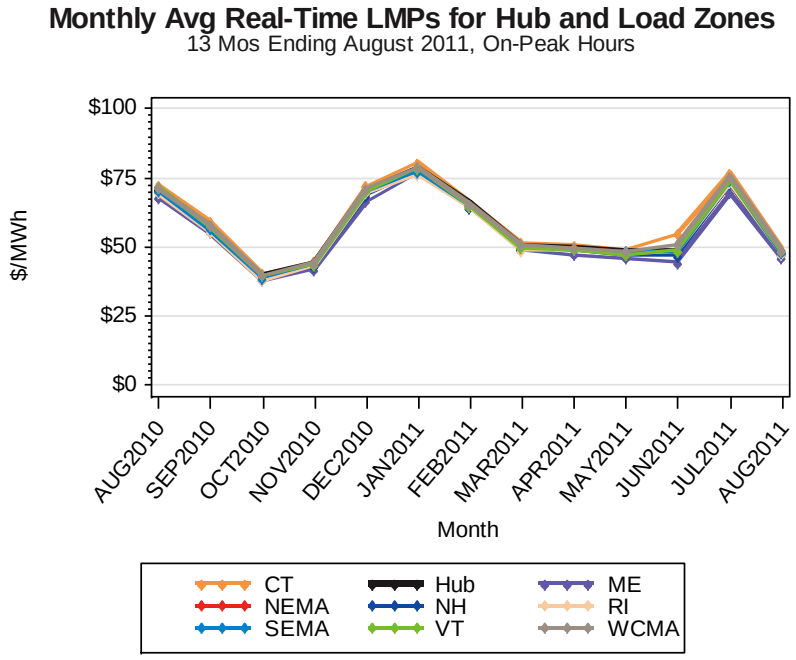
13 Mos Ending August 2011, On-Peak Hours



4.3 LMP Graphs, Real-Time Market, 13 Months Ending August 2011

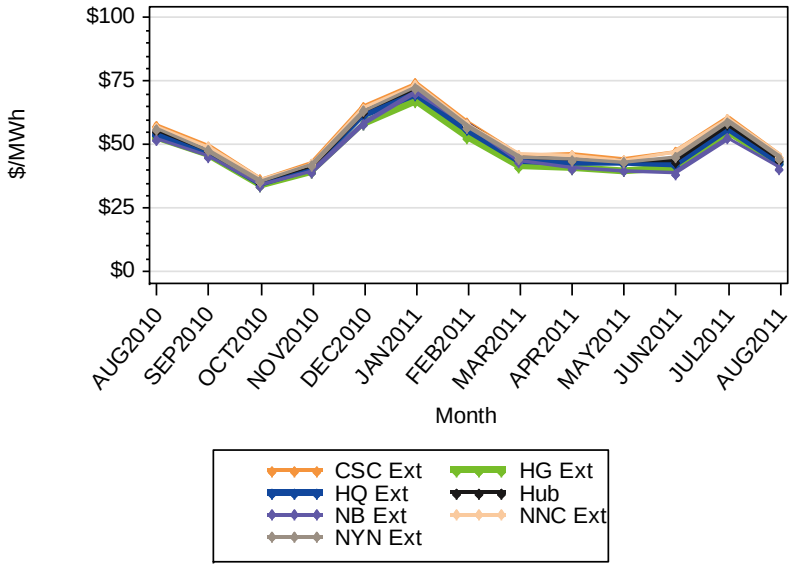
The following four graphs show the 13 month history of average hourly Real-Time LMPs for the Hub, Load Zones, and External Nodes on an overall and on-peak basis.





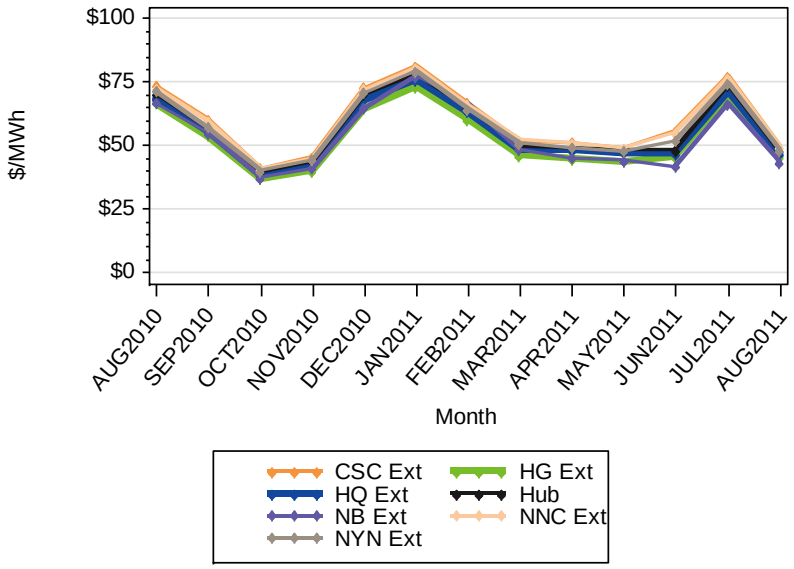
Monthly Avg Real-Time LMPs for Hub and External Nodes

13 Mos Ending August 2011, All Hours



Monthly Avg Real-Time LMPs for Hub and External Nodes

13 Mos Ending August 2011, On-Peak Hours



4.4 For More Information

The ISO provides a discussion of LMP results on a weekly basis in its Weekly Market Performance Report, located on the ISO's website at:
http://www.iso-ne.com/markets/mkt_anlys_rpts/wkly_mktops_rpts/index.html

The ISO also provides a discussion of LMP results on an annual basis in its Annual Market Performance Reports, located on the ISO's website at:
http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html

Downloadable Hub and Load Zone weekly and monthly LMP indices are located at:
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 at:
http://www.iso-ne.com/markets/hst_rpts/hstRpts.do?category=Hourly

Current Day-Ahead and Real-Time LMPs for the Hub and Load Zones can be monitored at:
http://www.iso-ne.com/portal/jsp/lmpmap/Index.jsp

A discussion of the calculation of LMPs can be found in the ISO's Market Rule 1 located at:
http://www.iso-ne.com/regulatory/tariff/sect_3/index.html

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.

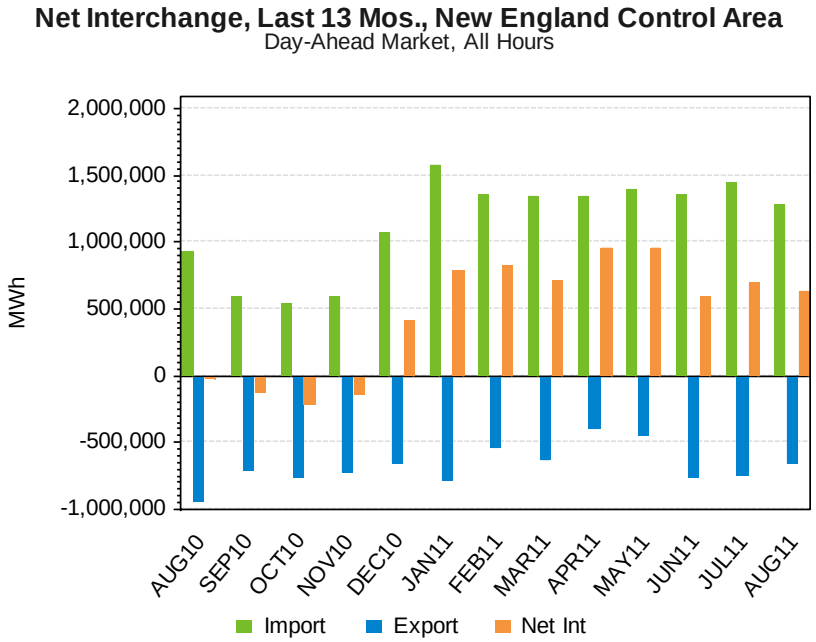
5.1 Net Interchange Summary, August 2011

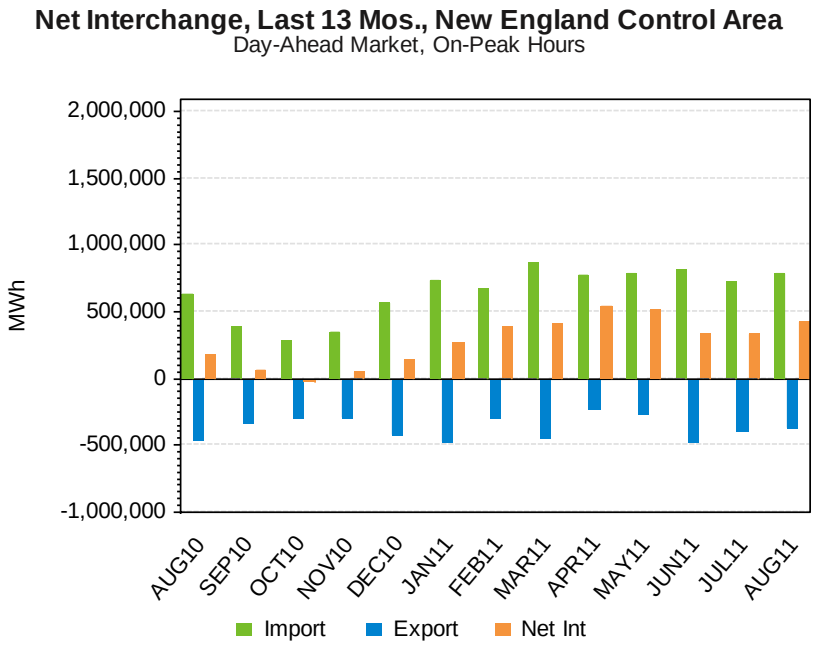
The following tables show summary statistics for imports and exports on the six external interfaces for both the Day-Ahead and Real-Time Markets:

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

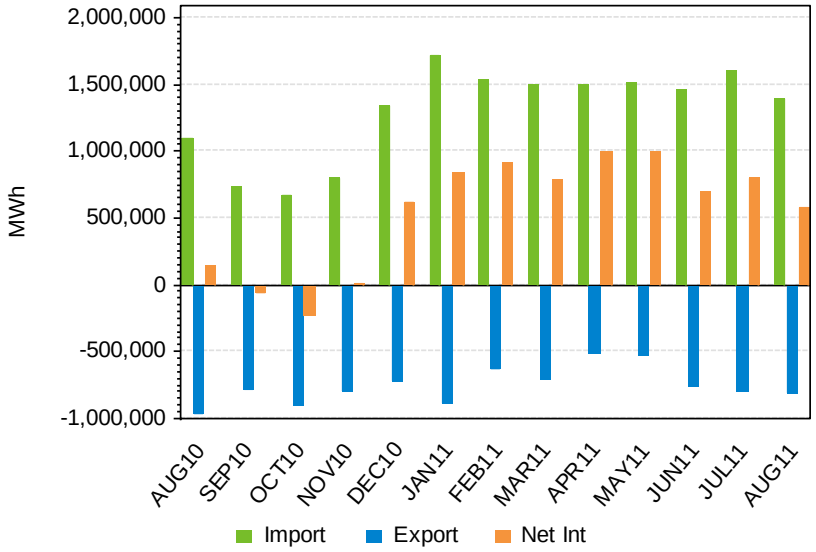
On/Off Peak	Interface	DA Total Exports (MWh)	DA Total Imports (MWh)	DA Net Int (MWh)	RT Total Exports (MWh)	RT Total Imports (MWh)	RT Net Int (MWh)
All Hours	NNC	-108,810	7,692	-101,118	-116,934	11,976	-104,958
	NY-CSC	-225,097	0	-225,097	-223,251	0	-223,251
	HQ HG	0	128,529	128,529	0	128,310	128,310
	HQ I/II	0	782,035	782,035	-210	784,615	784,405
	NY-N AC	-275,770	186,186	-89,584	-417,147	254,096	-163,051
	NB	-39,128	172,856	133,728	-46,698	206,689	159,991
Total	**All Hours**	**-648,804**	**1,277,298**	**628,493**	**-804,240**	**1,385,686**	**581,446**
Off-Peak	NNC	-49,584	4,613	-44,971	-52,963	6,644	-46,319
	NY-CSC	-107,012	0	-107,012	-105,166	0	-105,166
	HQ HG	0	48,323	48,323	0	48,140	48,140
	HQ I/II	0	310,562	310,562	-210	315,925	315,715
	NY-N AC	-105,062	61,596	-43,466	-166,866	100,466	-66,400
	NB	-15,664	65,680	50,016	-19,570	82,278	62,708
Total	Off-Peak	-277,322	490,774	213,452	-344,775	553,453	208,678
On-Peak	NNC	-59,226	3,079	-56,147	-63,971	5,332	-58,639
	NY-CSC	-118,085	0	-118,085	-118,085	0	-118,085
	HQ HG	0	80,206	80,206	0	80,170	80,170
	HQ I/II	0	471,472	471,472	0	468,690	468,690
	NY-N AC	-170,708	124,590	-46,118	-250,281	153,630	-96,651
	NB	-23,464	107,176	83,712	-27,128	124,411	97,283
Total	On-Peak	-371,482	786,524	415,041	-459,465	832,233	372,768

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

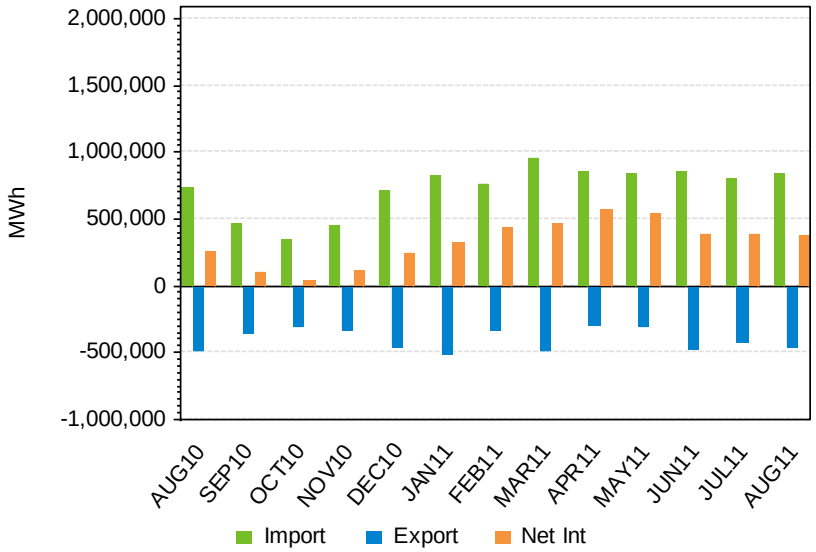




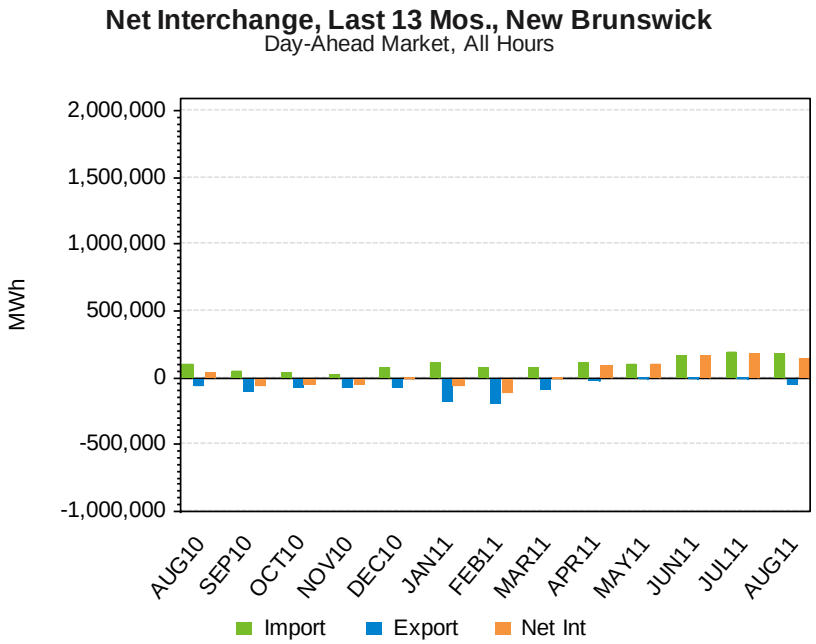
Net Interchange, Last 13 Mos., New England Control Area
Real-Time Market, All Hours

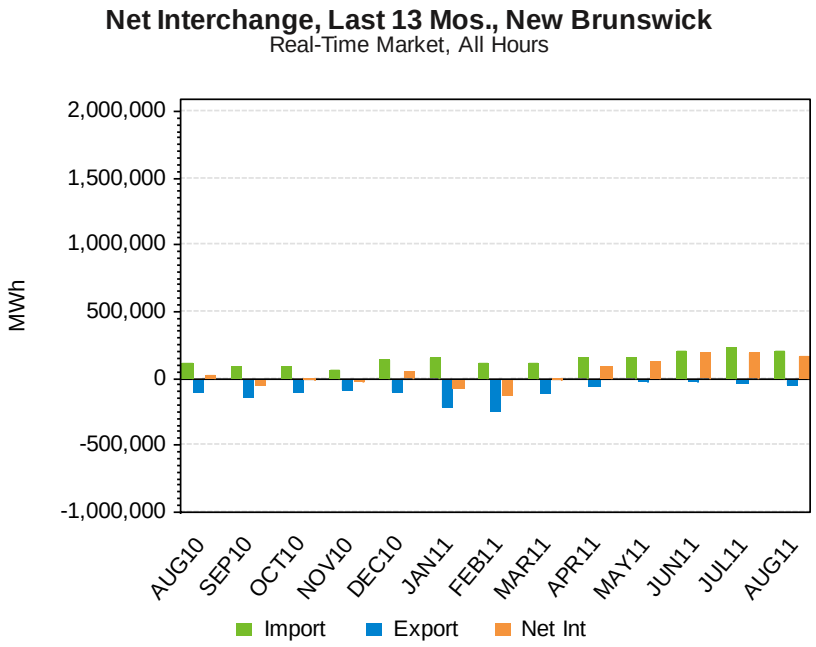


Net Interchange, Last 13 Mos., New England Control Area
Real-Time Market, On-Peak Hours

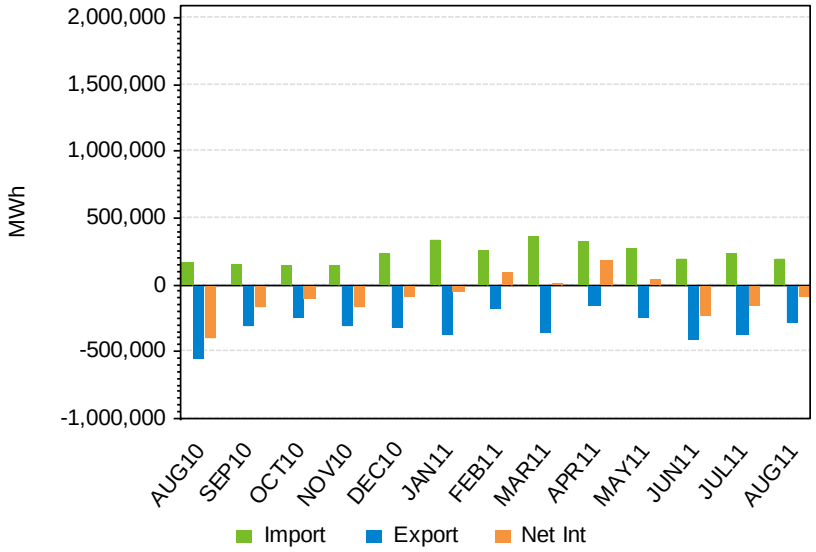


5.3 Net Interchange Summary by Interface, Last 13 Months

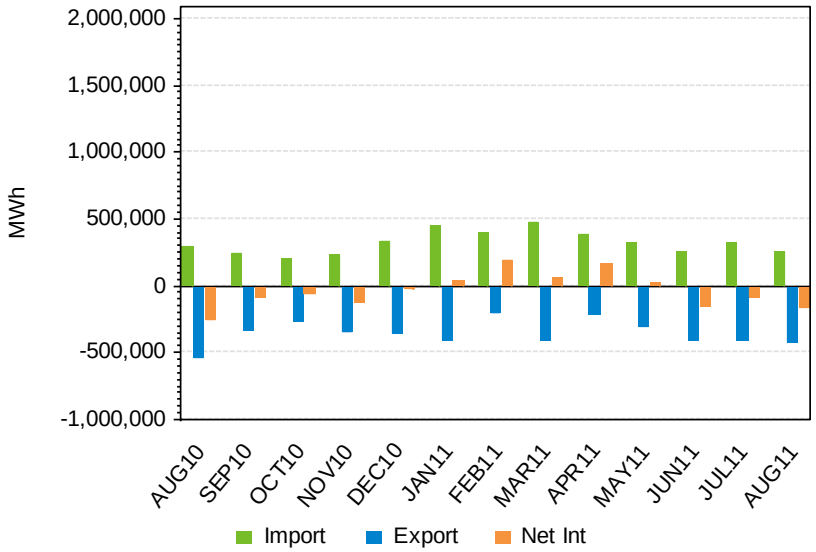




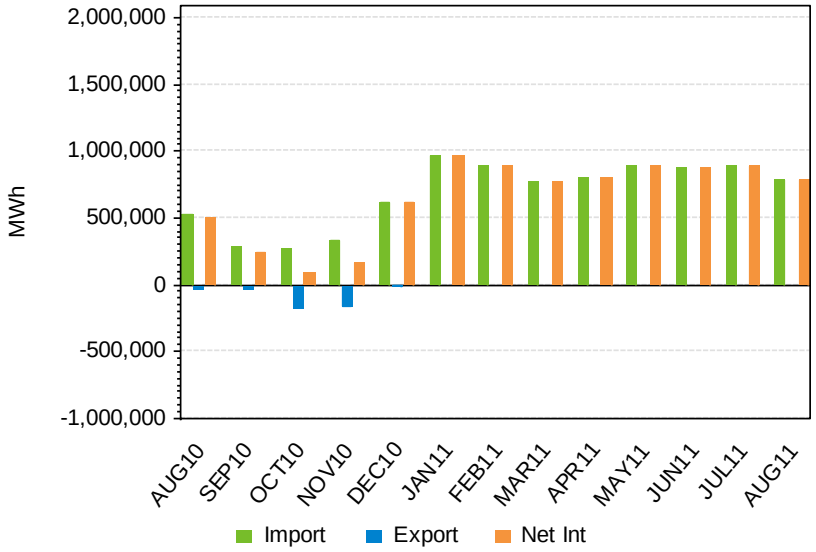
Net Interchange, Last 13 Mos., New York N-AC Ties
Day-Ahead Market, All Hours



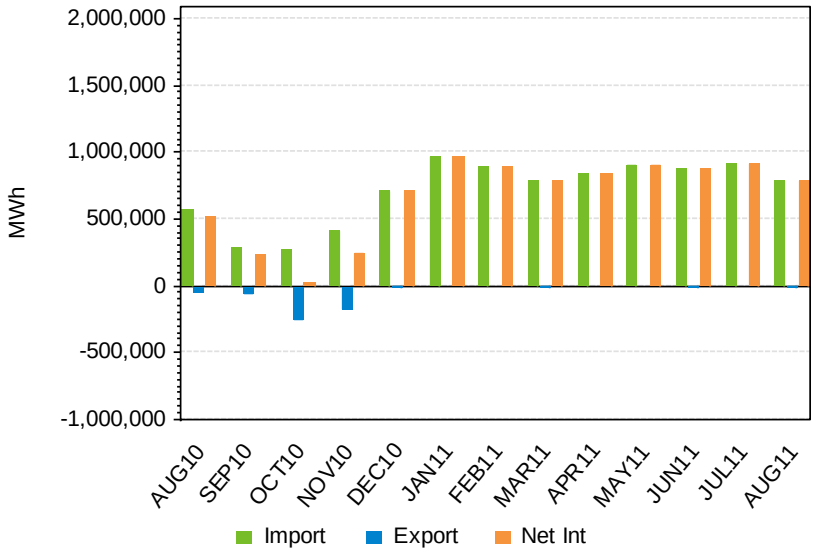
Net Interchange, Last 13 Mos., New York N-AC Ties
Real-Time Market, All Hours



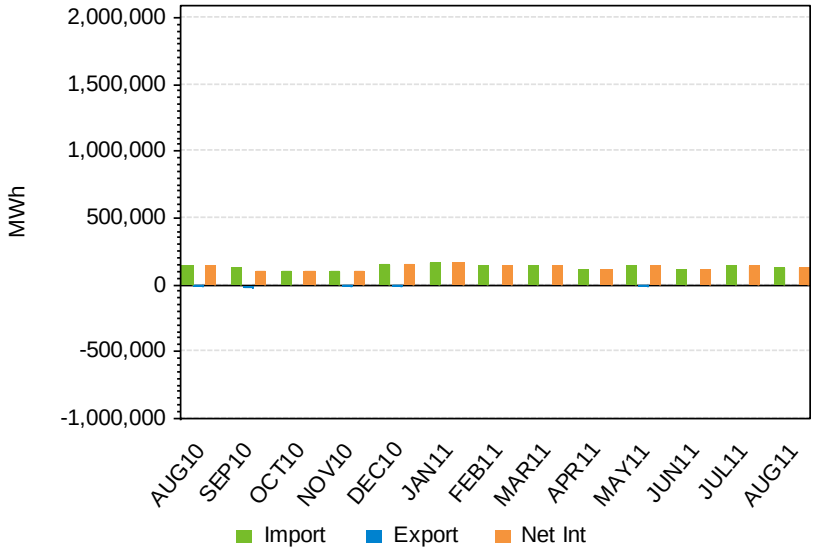
Net Interchange, Last 13 Mos., Hydro-Quebec Phase I/II
Day-Ahead Market, All Hours



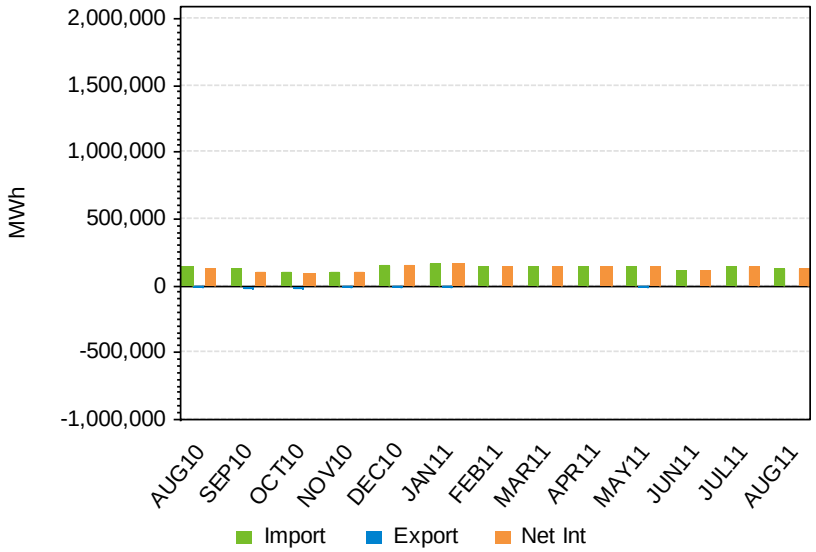
Net Interchange, Last 13 Mos., Hydro-Quebec Phase I/II
Real-Time Market, All Hours



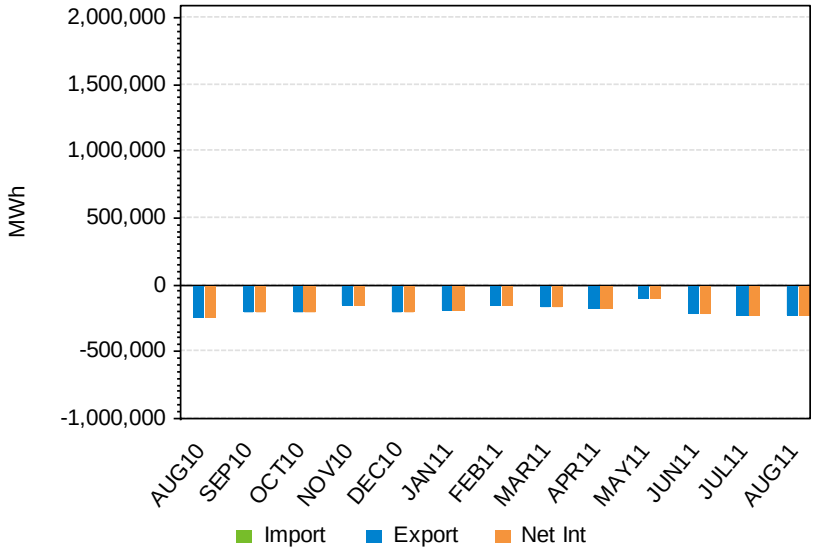
Net Interchange, Last 13 Mos., HQ Highgate
Day-Ahead Market, All Hours



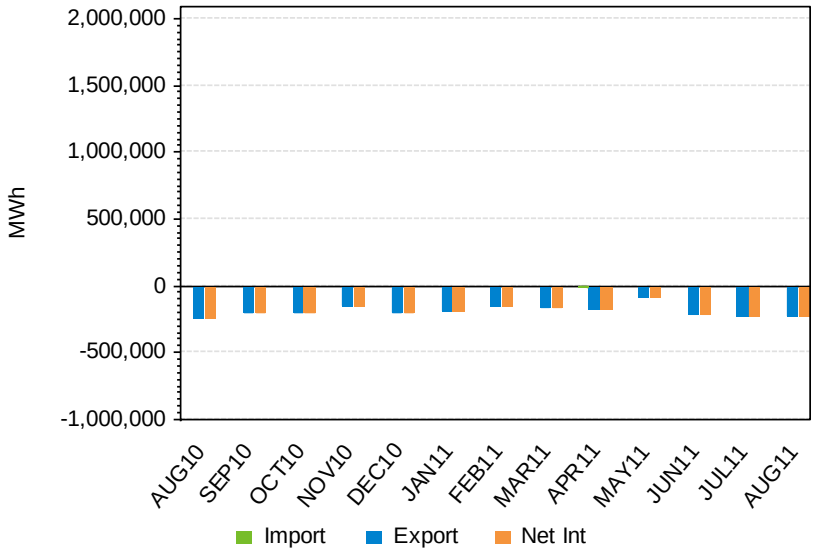
Net Interchange, Last 13 Mos., HQ Highgate
Real-Time Market, All Hours



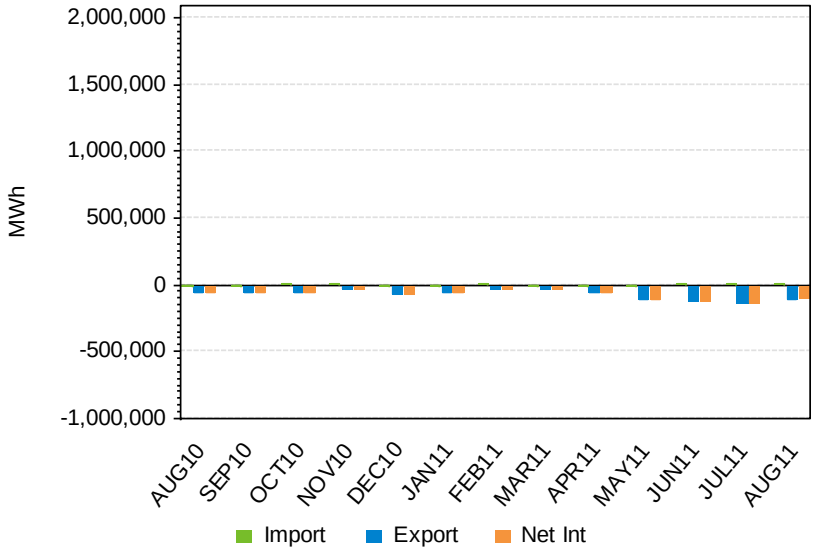
Net Interchange, Last 13 Mos., NY Cross Sound Cable
Day-Ahead Market, All Hours



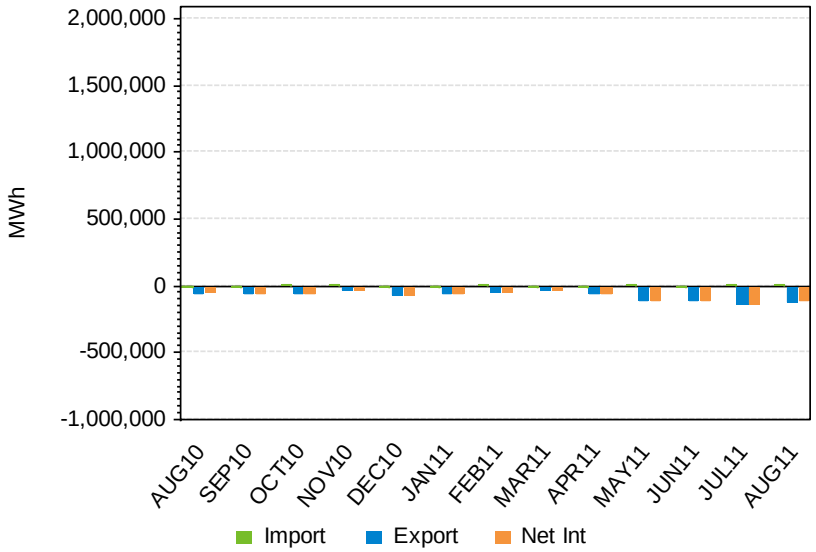
Net Interchange, Last 13 Mos., NY Cross Sound Cable
Real-Time Market, All Hours



Net Interchange, Last 13 Mos., Northport-Norwalk Cable
Day-Ahead Market, All Hours



Net Interchange, Last 13 Mos., Northport-Norwalk Cable
Real-Time Market, All Hours



5.4 For More Information

Selectable historical hourly net interchange for the New England Control can be found on the ISO's website at (select 'Interchange' in the drop-down under 'Step 1'):
http://www.iso-ne.com/markets/hst_rpts/hstRpts.do?category=Hourly

Monthly, daily, and hourly summaries of New England Control Area net interchange can be found on the ISO's web site at:
http://www.iso-ne.com/markets/hstdata/znl_info/index.html

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 at:
http://www.iso-ne.com/regulatory/tariff/sect_3/index.html

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 at:
http://www.iso-ne.com/rules_proceds/isone_mnls/index.html

A history of emergency purchases and sales from and to neighboring control areas can be found at:
http://www.iso-ne.com/stlmnts/emerg/index.html

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, August 2011

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	10,939	79,985	-$805,957	3,733	21,810	$145,755
Buy	On	13,779	102,947	-$1,297,369	4,233	23,571	$695,995
Buy	Buy Total	24,718	182,932	-$2,103,325	7,966	45,380	$841,750
Sell	Off	2,085	7,187	$568,697	108	274	-$3,026
Sell	On	2,161	7,472	$975,422	178	469	-$18,410
Sell	Sell Total	4,246	14,659	$1,544,119	286	743	-$21,436
Grand Total	Grand Total	28,964	197,591	-$559,206	8,252	46,123	$820,314

6.1.2 Number of Auction Participants, August 2011

Auction Period	Monthly or Long-Term	No. of Bidders
Aug 2011	MO	33

6.1.3 Monthly FTR Auction Results, Last 13 Months

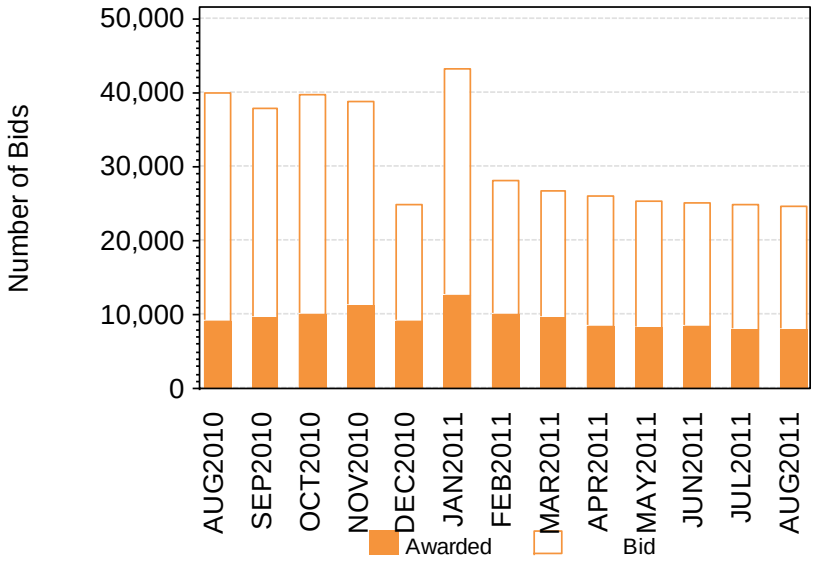
Auction Month	Bids to Buy or Offers to Sell	No. of Bids or Offers	Bid or Offered MW-Mos.	Bid or Offered Dollars	No. of Awards	Awarded MW-Mos.	Awarded Dollars
AUG 2010	Buy	40,026	297,097	-$5,140,157	9,045	51,116	$1,643,934
AUG 2010	Sell	7,692	22,108	$3,043,722	313	962	-$96,600
AUG 2010	Tot	47,718	319,205	-$2,096,435	9,358	52,077	$1,547,334
SEP 2010	Buy	37,845	292,821	-$4,423,529	9,672	47,012	$1,055,899
SEP 2010	Sell	7,665	22,086	$3,267,558	357	1,048	-$162,512
SEP 2010	Tot	45,510	314,907	-$1,155,971	10,029	48,060	$893,387
OCT 2010	Buy	39,729	298,549	-$944,533	10,114	52,363	$1,133,765

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 2010	Sell	7,571	22,456	$3,872,508	347	1,153	-$210,618
OCT 2010	Tot	47,300	321,004	$2,927,976	10,461	53,516	$923,147
NOV 2010	Buy	38,768	304,050	-$2,123,085	11,109	59,827	$1,001,900
NOV 2010	Sell	7,474	22,032	$2,931,530	227	537	-$32,608
NOV 2010	Tot	46,242	326,082	$808,444	11,336	60,364	$969,292
DEC 2010	Buy	24,851	187,475	-$2,767,650	9,144	51,188	$819,043
DEC 2010	Sell	7,417	21,235	$2,811,101	80	223	-$28,735
DEC 2010	Tot	32,268	208,710	$43,451	9,224	51,411	$790,308
JAN 2011	Buy	43,122	313,348	-$2,723,172	12,635	57,882	$936,085
JAN 2011	Sell	5,715	18,874	$2,965,010	224	356	-$24,960
JAN 2011	Tot	48,837	332,221	$241,838	12,859	58,237	$911,126
FEB 2011	Buy	28,128	234,568	-$4,149,076	9,962	56,993	$592,995
FEB 2011	Sell	3,037	11,808	$1,309,695	102	166	-$5,531
FEB 2011	Tot	31,165	246,377	-$2,839,380	10,064	57,159	$587,463
MAR 2011	Buy	26,843	215,392	-$3,547,494	9,664	57,702	$553,602
MAR 2011	Sell	4,367	15,240	$1,676,605	143	298	-$13,829
MAR 2011	Tot	31,210	230,632	-$1,870,889	9,807	58,000	$539,773
APR 2011	Buy	26,128	201,523	-$3,310,869	8,324	48,409	$654,652
APR 2011	Sell	4,360	17,137	$1,706,127	254	583	-$37,419
APR 2011	Tot	30,488	218,660	-$1,604,742	8,578	48,992	$617,234
MAY 2011	Buy	25,306	202,030	-$2,885,154	8,244	44,928	$516,434
MAY 2011	Sell	4,703	15,479	$1,477,030	265	510	-$21,759
MAY 2011	Tot	30,009	217,510	-$1,408,124	8,509	45,438	$494,675
JUN 2011	Buy	25,101	179,637	-$2,979,861	8,344	43,395	$498,311
JUN 2011	Sell	4,270	14,854	$1,377,329	137	259	-$4,605
JUN 2011	Tot	29,371	194,491	-$1,602,532	8,481	43,654	$493,706
JUL 2011	Buy	24,875	181,883	-$2,171,942	7,997	43,519	$752,017
JUL 2011	Sell	4,255	14,892	$1,593,615	234	558	-$31,123
JUL 2011	Tot	29,130	196,775	-$578,327	8,231	44,077	$720,894
AUG 2011	Buy	24,718	182,932	-$2,103,325	7,966	45,380	$841,750
AUG 2011	Sell	4,246	14,659	$1,544,119	286	743	-$21,436
AUG 2011	Tot	28,964	197,591	-$559,206	8,252	46,123	$820,314

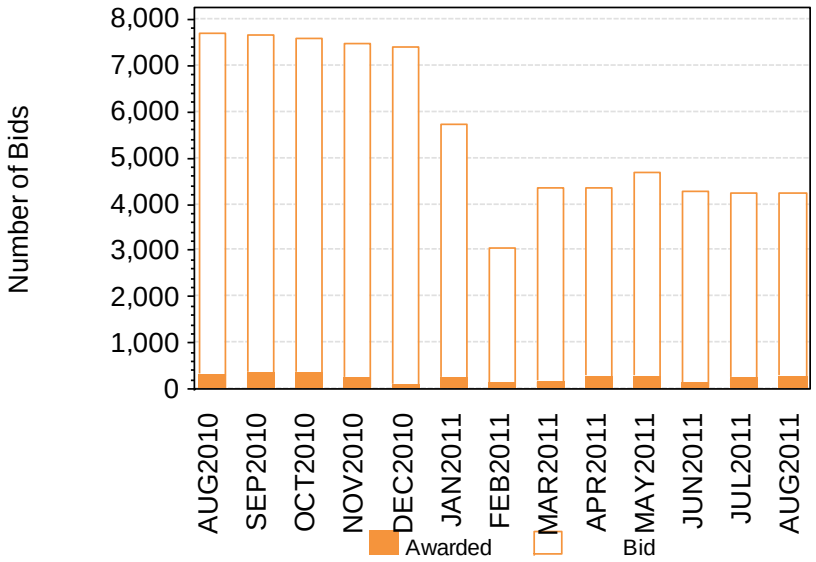
6.2 Monthly FTR Auction Results, Last 13 Months

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.

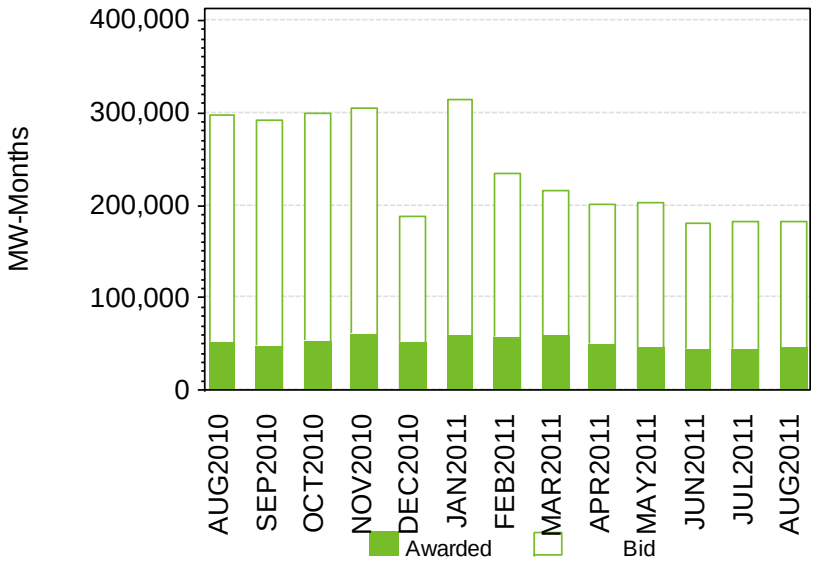
Monthly FTR Auctions: Number of Bids, Buy Activity
13 Months Ending August 2011



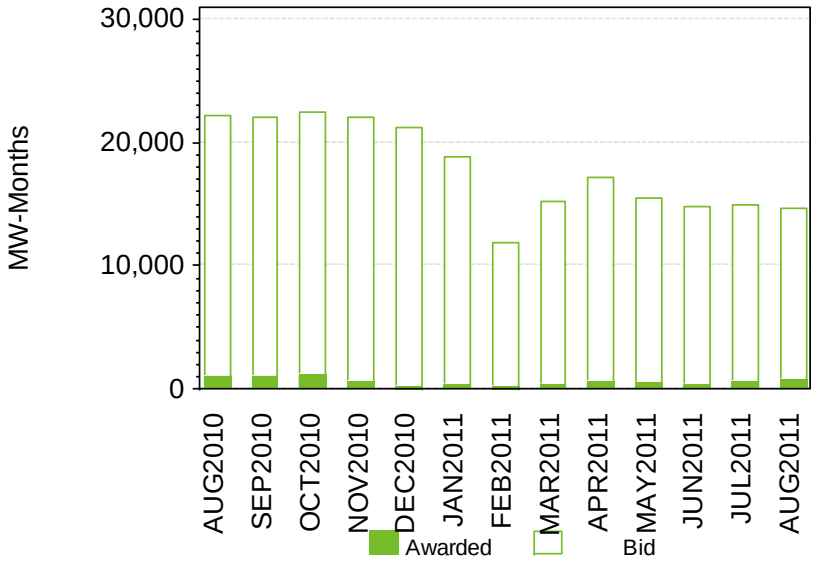
Monthly FTR Auctions: Number of Bids, Sell Activity
13 Months Ending August 2011



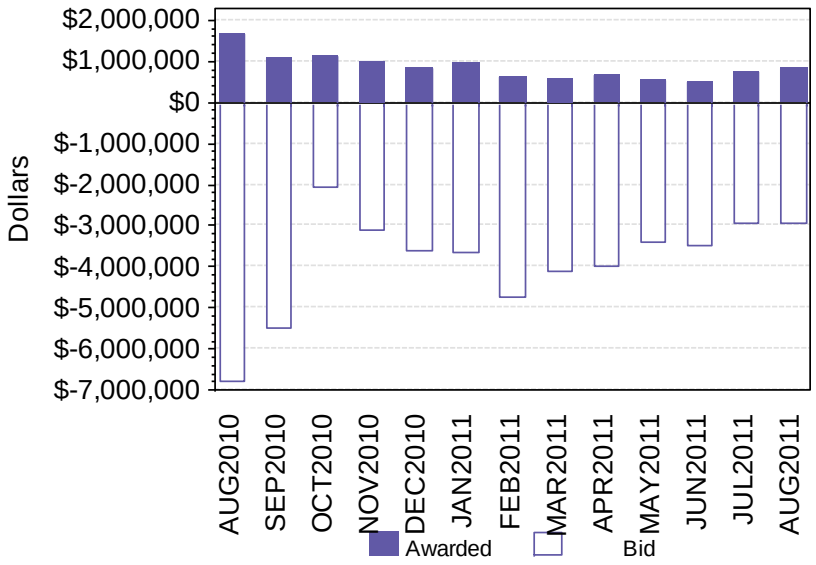
Monthly FTR Auctions: MW-Months, Buy Activity
13 Months Ending August 2011



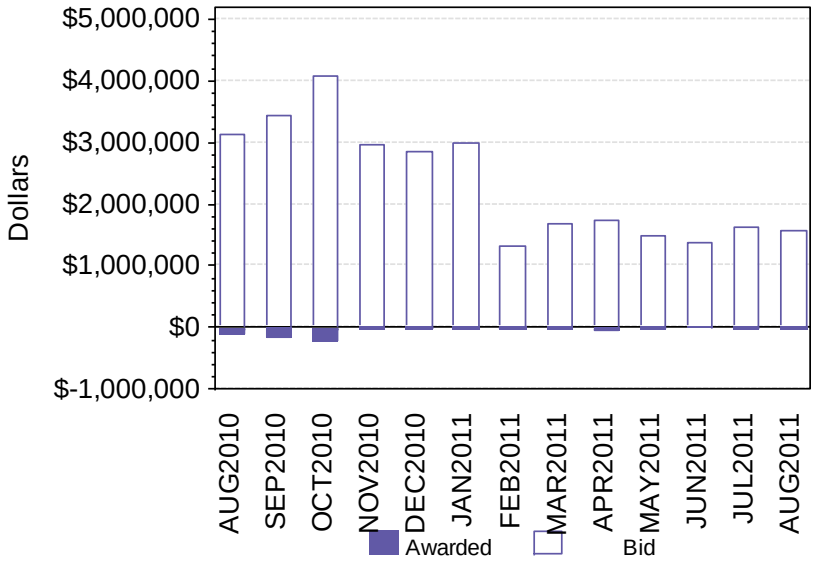
Monthly FTR Auctions: MW-Months, Sell Activity
13 Months Ending August 2011



Monthly FTR Auctions: Dollars, Buy Activity
13 Months Ending August 2011

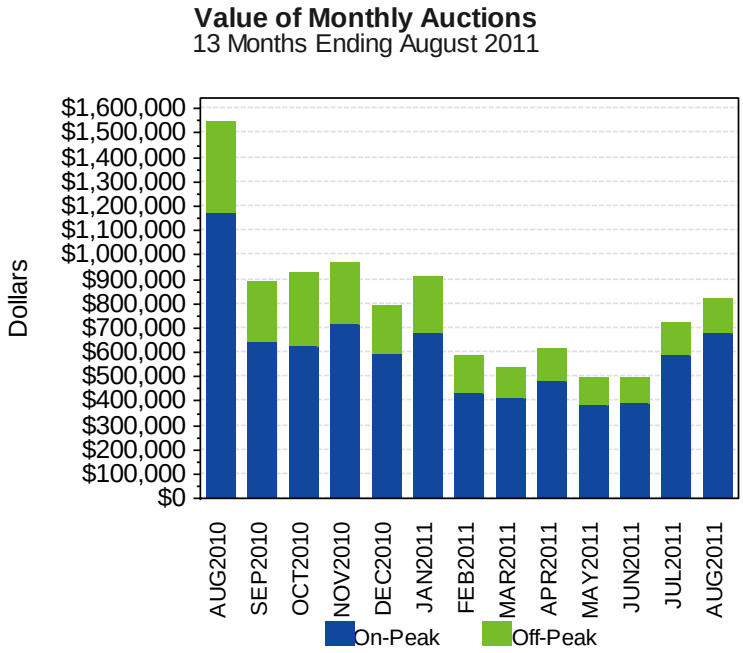


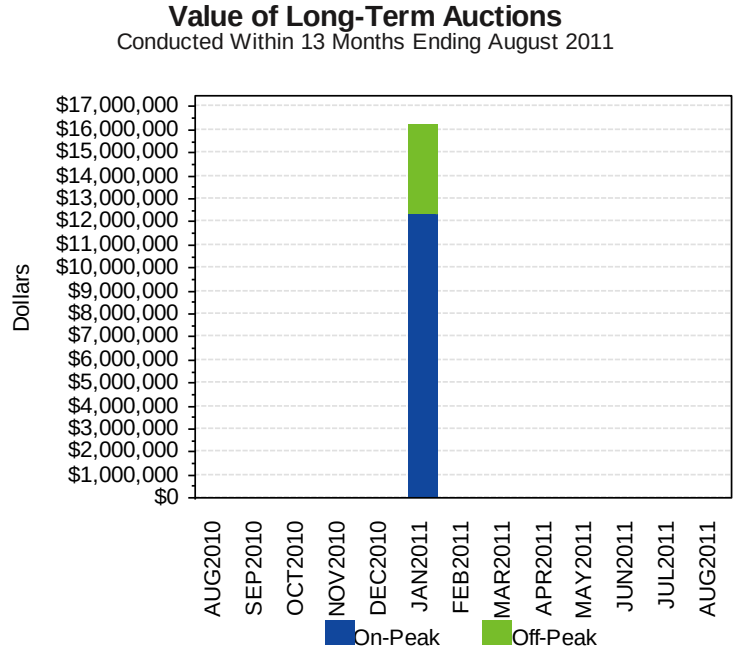
Monthly FTR Auctions: Dollars, Sell Activity
13 Months Ending August 2011

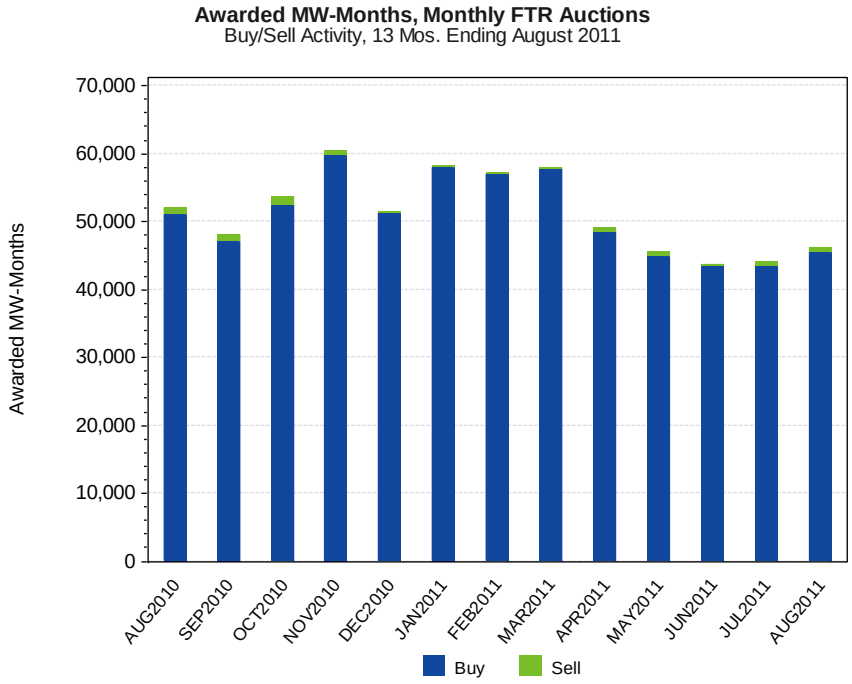


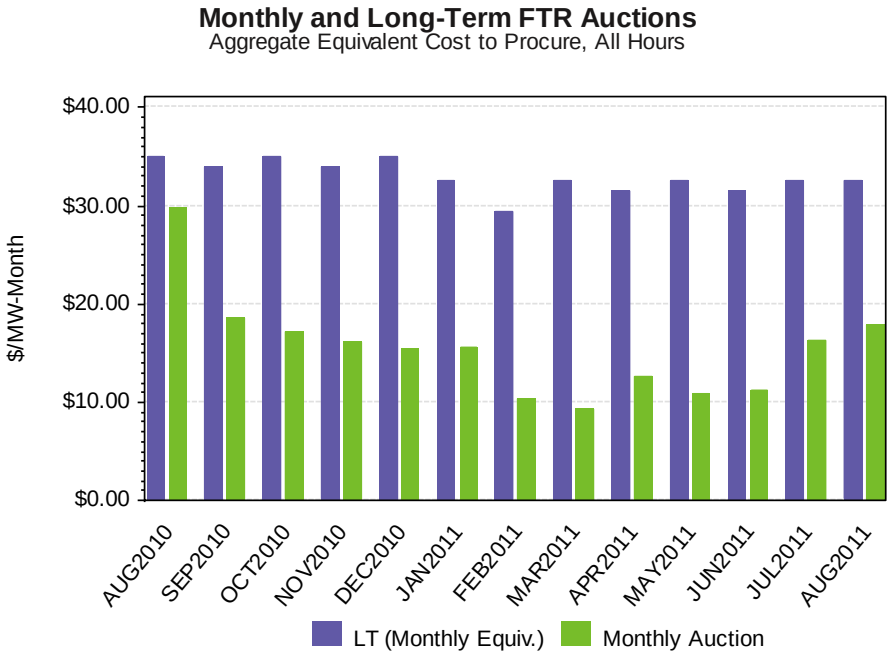
6.3 Auction Value, Last 13 Months

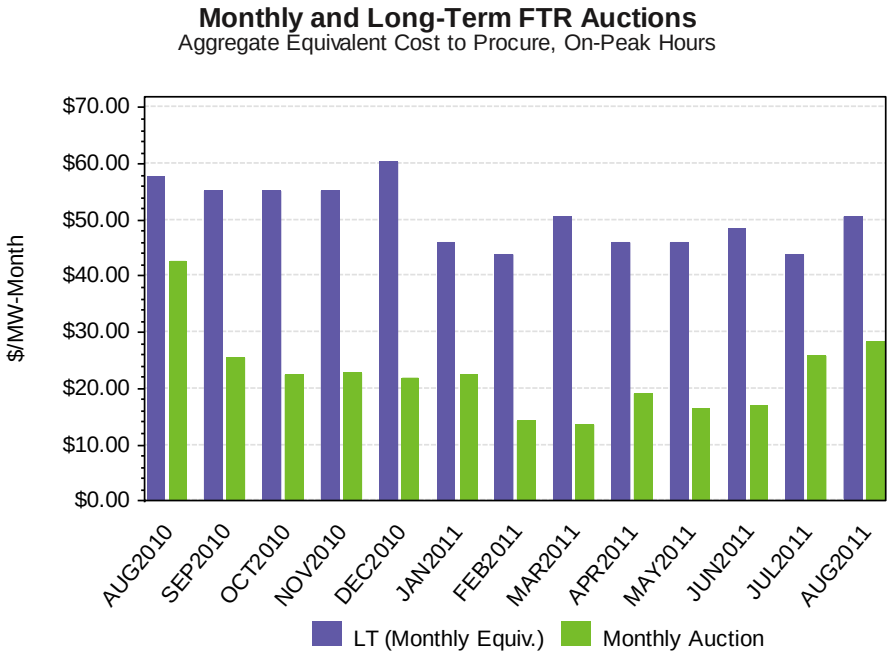
The next series of graphs show summaries of FTR Auction value and on/off-peak activity over the last 13 months.

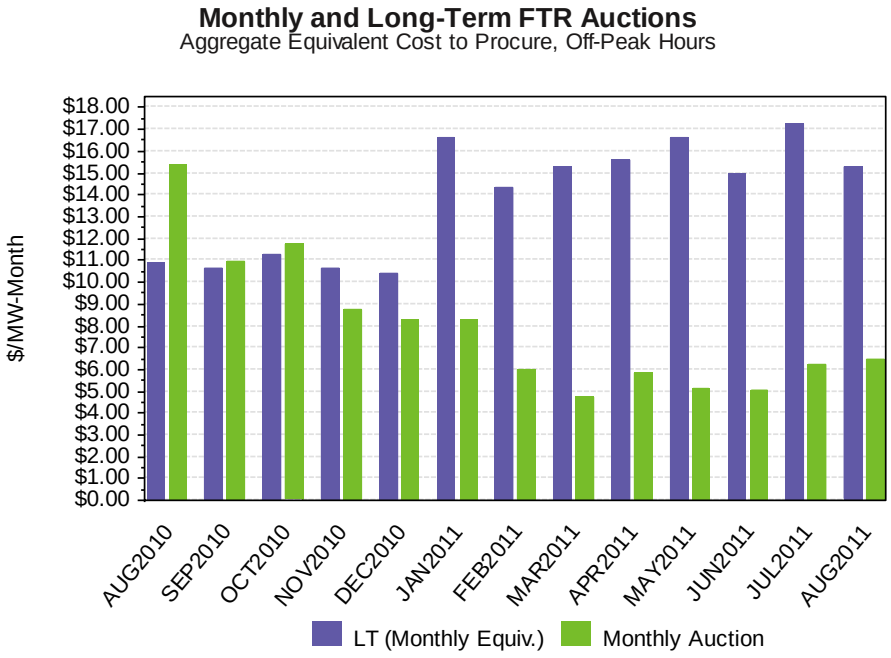












6.4 For More Information

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 at:
http://www.iso-ne.com/regulatory/tariff/sect_3/index.html

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 at:
http://www.iso-ne.com/rules_proceds/isone_mnls/index.html

Information about the monthly and long-term FTR auctions can be found on the ISO's web site at:
http://www.iso-ne.com/markets/othrmkts_data/ftr/index.html

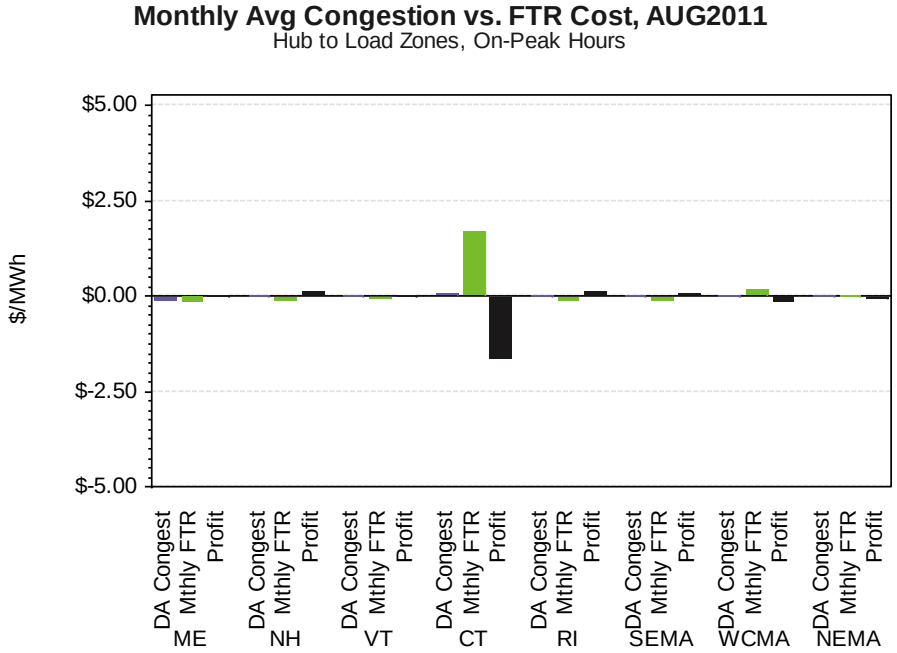
7. Effectiveness of FTRs

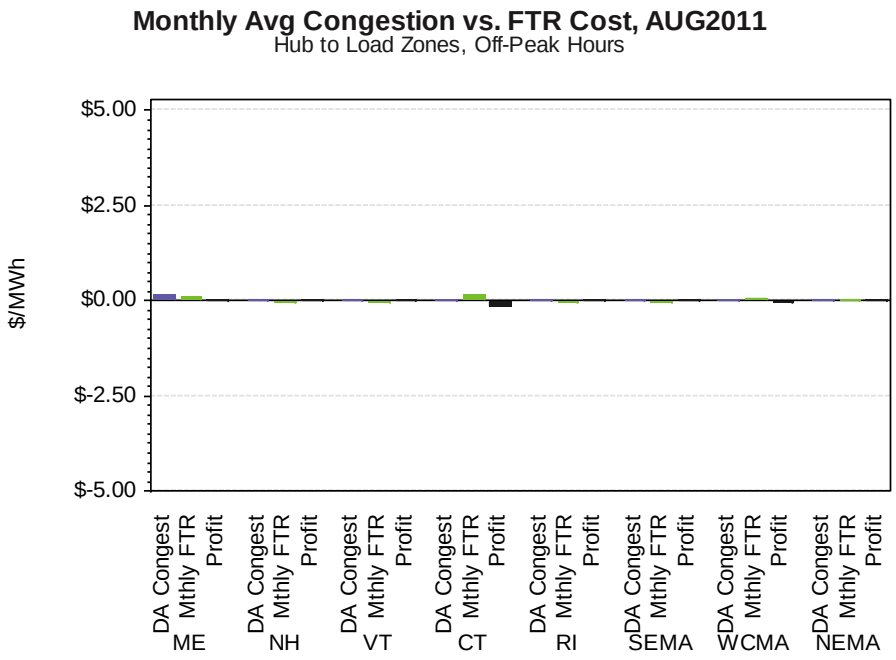
7.1 FTRs as a Congestion Hedging Instrument

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 August 2011, 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	Aug-10	-$0.05	-$0.28	$0.23
ME	Sep-10	$1.58	-$0.53	$2.11
ME	Oct-10	-$0.07	-$0.47	$0.40
ME	Nov-10	-$0.07	-$0.10	$0.02
ME	Dec-10	-$0.04	-$0.08	$0.04
ME	Jan-11	$5.50	$0.00	$5.50
ME	Feb-11	$1.03	$0.01	$1.02
ME	Mar-11	$1.31	$0.24	$1.07
ME	Apr-11	-$0.52	-$0.12	-$0.40
ME	May-11	-$0.12	-$0.16	$0.04
ME	Jun-11	-$0.33	-$0.10	-$0.23
ME	Jul-11	-$0.09	-$0.21	$0.11
ME	Aug-11	-$0.10	-$0.12	$0.02

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
NH	Aug-10	-$0.03	-$0.15	$0.12
NH	Sep-10	-$0.21	-$0.30	$0.09
NH	Oct-10	-$0.01	-$0.26	$0.25
NH	Nov-10	$0.05	-$0.04	$0.09
NH	Dec-10	-$0.01	$0.00	-$0.01
NH	Jan-11	$0.00	-$0.03	$0.03
NH	Feb-11	$0.00	-$0.02	$0.02
NH	Mar-11	$0.05	-$0.03	$0.08
NH	Apr-11	$0.01	-$0.05	$0.06
NH	May-11	-$0.10	-$0.07	-$0.04
NH	Jun-11	-$0.26	-$0.08	-$0.18
NH	Jul-11	$0.02	-$0.14	$0.16
NH	Aug-11	-$0.01	-$0.10	$0.09

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
VT	Aug-10	$0.06	-$0.01	$0.08
VT	Sep-10	$0.28	$0.38	-$0.10
VT	Oct-10	$0.11	$0.57	-$0.46
VT	Nov-10	$0.02	$0.08	-$0.06
VT	Dec-10	-$0.02	$0.04	-$0.06
VT	Jan-11	$0.05	$0.01	$0.04
VT	Feb-11	$0.00	$0.01	-$0.01
VT	Mar-11	$0.07	$0.00	$0.07
VT	Apr-11	$0.00	-$0.01	$0.01
VT	May-11	$0.00	$0.00	$0.00
VT	Jun-11	-$0.10	-$0.02	-$0.08
VT	Jul-11	$0.01	$0.13	-$0.12
VT	Aug-11	$0.00	-$0.04	$0.03

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
CT	Aug-10	$2.88	$2.25	$0.63
CT	Sep-10	$1.76	$2.25	-$0.49
CT	Oct-10	$0.64	$1.90	-$1.26
CT	Nov-10	$0.38	$1.62	-$1.24
CT	Dec-10	$0.38	$1.70	-$1.32
CT	Jan-11	$0.24	$1.73	-$1.49
CT	Feb-11	$0.02	$0.84	-$0.82
CT	Mar-11	$1.14	$0.84	$0.30
CT	Apr-11	$0.23	$2.51	-$2.28
CT	May-11	-$0.02	$0.86	-$0.89
CT	Jun-11	$0.79	$0.80	$0.00
CT	Jul-11	$1.40	$0.87	$0.52
CT	Aug-11	$0.07	$1.70	-$1.62

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
RI	Aug-10	-$0.28	-$0.05	-$0.23
RI	Sep-10	-$0.64	-$0.27	-$0.36
RI	Oct-10	-$0.47	-$0.38	-$0.09
RI	Nov-10	-$0.24	-$0.06	-$0.18
RI	Dec-10	$0.00	-$0.05	$0.05
RI	Jan-11	-$0.13	-$0.03	-$0.10
RI	Feb-11	$0.00	-$0.01	$0.01
RI	Mar-11	-$0.25	-$0.05	-$0.20
RI	Apr-11	$0.00	-$0.03	$0.03
RI	May-11	-$0.24	-$0.04	-$0.19
RI	Jun-11	-$0.17	-$0.09	-$0.08
RI	Jul-11	$0.03	-$0.06	$0.09
RI	Aug-11	-$0.01	-$0.10	$0.09

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
SEMA	Aug-10	-$0.21	-$0.06	-$0.15
SEMA	Sep-10	-$0.63	-$0.28	-$0.35
SEMA	Oct-10	-$0.29	-$0.38	$0.09
SEMA	Nov-10	$0.13	-$0.05	$0.18
SEMA	Dec-10	-$0.02	-$0.03	$0.01
SEMA	Jan-11	-$0.08	$0.00	-$0.09
SEMA	Feb-11	$0.00	$0.00	$0.00
SEMA	Mar-11	$0.06	-$0.02	$0.08
SEMA	Apr-11	-$0.08	-$0.01	-$0.06
SEMA	May-11	-$0.11	-$0.03	-$0.08
SEMA	Jun-11	-$0.08	-$0.06	-$0.01
SEMA	Jul-11	$0.02	-$0.15	$0.17
SEMA	Aug-11	-$0.01	-$0.06	$0.05

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
WCMA	Aug-10	$0.33	$0.34	-$0.01
WCMA	Sep-10	$0.09	$0.30	-$0.21
WCMA	Oct-10	$0.10	$0.35	-$0.25
WCMA	Nov-10	$0.01	$0.16	-$0.15
WCMA	Dec-10	$0.35	$0.14	$0.21
WCMA	Jan-11	$0.11	$0.12	-$0.01
WCMA	Feb-11	$0.04	$0.15	-$0.11
WCMA	Mar-11	$0.79	$0.09	$0.71
WCMA	Apr-11	$0.01	$0.10	-$0.09
WCMA	May-11	$0.09	$0.08	$0.01
WCMA	Jun-11	$0.47	$0.06	$0.41
WCMA	Jul-11	$0.30	$0.25	$0.05
WCMA	Aug-11	$0.03	$0.13	-$0.10

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
NEMA	Aug-10	-$0.13	$0.02	-$0.15
NEMA	Sep-10	-$0.25	-$0.19	-$0.06
NEMA	Oct-10	-$0.11	-$0.16	$0.05
NEMA	Nov-10	$0.08	$0.05	$0.03
NEMA	Dec-10	-$0.02	$0.05	-$0.07
NEMA	Jan-11	-$0.04	$0.05	-$0.09
NEMA	Feb-11	$0.00	$0.10	-$0.10
NEMA	Mar-11	$0.06	$0.05	$0.01
NEMA	Apr-11	$0.00	$0.02	-$0.02
NEMA	May-11	-$0.06	$0.05	-$0.10
NEMA	Jun-11	-$0.04	$0.01	-$0.05
NEMA	Jul-11	$0.57	-$0.08	$0.65
NEMA	Aug-11	-$0.01	$0.02	-$0.03

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	Total Auction Distribution
Aug-10	-$3,122,544	$582	$13,657	$2,770,677	$2,784,916	$337,628	$3,122,544
Sep-10	-$2,417,784	$107	$8,994	$2,316,508	$2,325,609	$92,175	$2,417,784
Oct-10	-$2,498,358	$117	$8,630	$2,106,462	$2,115,210	$383,148	$2,498,358
Nov-10	-$2,493,689	$149	$10,151	$2,276,469	$2,286,769	$206,920	$2,493,689
Dec-10	-$2,365,518	$130	$9,375	$2,243,024	$2,252,529	$112,990	$2,365,518
Jan-11	-$2,290,839	$131	$8,836	$2,053,136	$2,062,103	$228,736	$2,290,839
Feb-11	-$1,833,656	$104	$9,839	$1,658,053	$1,667,996	$165,659	$1,833,656
Mar-11	-$1,919,486	$204	$8,507	$1,783,687	$1,792,399	$127,087	$1,919,486
Apr-11	-$1,952,440	$99	$6,940	$1,789,840	$1,796,879	$155,561	$1,952,440
May-11	-$1,874,388	$268	$9,394	$1,671,324	$1,680,986	$193,401	$1,874,388
Jun-11	-$1,828,912	$20	$9,836	$1,596,626	$1,606,482	$222,430	$1,828,912
Jul-11	-$2,100,607	$14	$5,948	$1,911,163	$1,917,126	$183,481	$2,100,607
Aug-11	-$2,200,027	$24	$9,397	$2,029,632	$2,039,053	$160,974	$2,200,027

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**
Aug-10	$21,983	$34,704	$32,844	$1,625,279	$32,632	$65,636	$226,332	$202,514
Sep-10	$12,613	$32,145	$44,430	$1,348,635	$25,892	$51,954	$189,363	$167,276
Oct-10	$12,522	$32,067	$50,565	$1,168,112	$22,216	$46,392	$178,709	$171,799
Nov-10	$24,627	$37,181	$36,331	$1,344,950	$25,651	$61,820	$176,214	$194,001
Dec-10	$19,457	$36,285	$31,550	$1,336,028	$24,198	$50,901	$170,757	$174,601
Jan-11	$33,173	$39,505	$49,213	$1,030,544	$20,361	$48,912	$173,325	$167,278
Feb-11	$23,430	$30,371	$41,951	$766,962	$16,556	$40,920	$155,461	$173,896
Mar-11	$81,328	$34,771	$48,834	$802,049	$17,560	$44,999	$156,415	$163,848
Apr-11	$14,857	$35,352	$47,989	$923,227	$16,299	$40,740	$151,125	$148,836
May-11	$11,363	$36,372	$51,428	$789,472	$17,016	$42,120	$162,956	$167,905
Jun-11	$14,370	$32,438	$48,206	$768,998	$15,994	$39,263	$154,875	$160,738
Jul-11	$15,020	$36,003	$54,841	$953,101	$33,588	$47,155	$200,416	$169,592
Aug-11	$15,820	$31,695	$46,615	$1,114,129	$19,476	$45,332	$175,555	$172,147

Off Peak								
Month	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Aug-10	$72,100	$9,837	$12,747	$251,320	$6,852	$15,561	$127,747	$46,828
Sep-10	$59,329	$7,370	$16,917	$242,939	$4,859	$12,121	$78,668	$31,099
Oct-10	$62,981	$9,522	$22,123	$218,003	$4,194	$10,122	$73,162	$32,721
Nov-10	$66,548	$7,178	$7,888	$206,811	$4,654	$13,078	$41,926	$37,911
Dec-10	$88,429	$7,370	$7,612	$214,116	$4,396	$12,186	$38,425	$36,218
Jan-11	$77,755	$6,866	$10,550	$245,911	$9,635	$22,498	$83,928	$42,649
Feb-11	$69,676	$4,510	$8,985	$203,018	$8,015	$18,395	$69,100	$36,749
Mar-11	$92,250	$5,629	$10,662	$191,791	$8,600	$21,295	$75,228	$37,142
Apr-11	$26,189	$6,596	$11,061	$240,064	$7,996	$19,347	$72,618	$34,583
May-11	$22,688	$5,435	$10,431	$226,437	$7,849	$19,313	$73,608	$36,592
Jun-11	$30,447	$5,309	$9,892	$183,821	$7,934	$18,583	$78,737	$36,877
Jul-11	$36,999	$7,773	$11,798	$195,965	$9,209	$22,008	$85,339	$38,318
Aug-11	$44,819	$5,319	$9,873	$212,349	$8,932	$21,011	$80,015	$35,966

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 at:
http://www.iso-ne.com/regulatory/tariff/sect_3/index.html

The business rules and procedures for FTR Auction Revenue Settlement for August 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 at:
http://www.iso-ne.com/rules_proceds/isone_mnls/index.html

The methodology for and details of ARR Contracts can be found at:
http://www.iso-ne.com/markets/othrmkts_data/ftr/arr_info/index.html

9. Reserve Markets

9.1 Reserve Market Summary

The tenth Forward Reserve Market Auction, covering the Summer 2011 Procurement Period (June-September) cleared on April 29, 2010. The results may be found on the ISO's website at the following link: http://www.iso-ne.com/markets/othrmkts_data/res_mkt/summ/index.html.

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 August 2011, the threshold price was set at $74.50.

9.2 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.

9.2.1 FRM Payment Summary by Reserve Zone, August 2011

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	$992,202	$950,479	-$62,656	$0	$887,823	89%
SYSTEM	TMOR	$405,278	$369,645	-$53,522	$0	$316,123	78%
SYSTEM	TOTAL	$1,397,480	$1,320,124	-$116,178	$0	$1,203,946	86%
ROS	TMNSR	$653,921	$615,386	-$57,867	$0	$557,520	85%
ROS	TMOR	$12,622	$10,253	-$3,559	$0	$6,694	53%
ROS	TOTAL	$666,544	$625,640	-$61,426	$0	$564,214	85%
SWCT	TMNSR	$0	$0	$0	$0	$0	n/a
SWCT	TMOR	$167,075	$147,347	-$29,634	$0	$117,713	70%
SWCT	TOTAL	$167,075	$147,347	-$29,634	$0	$117,713	70%
CT	TMNSR	$338,280	$335,092	-$4,789	$0	$330,303	98%
CT	TMOR	$225,580	$212,046	-$20,330	$0	$191,716	85%
CT	TOTAL	$563,861	$547,138	-$25,118	$0	$522,019	93%
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.

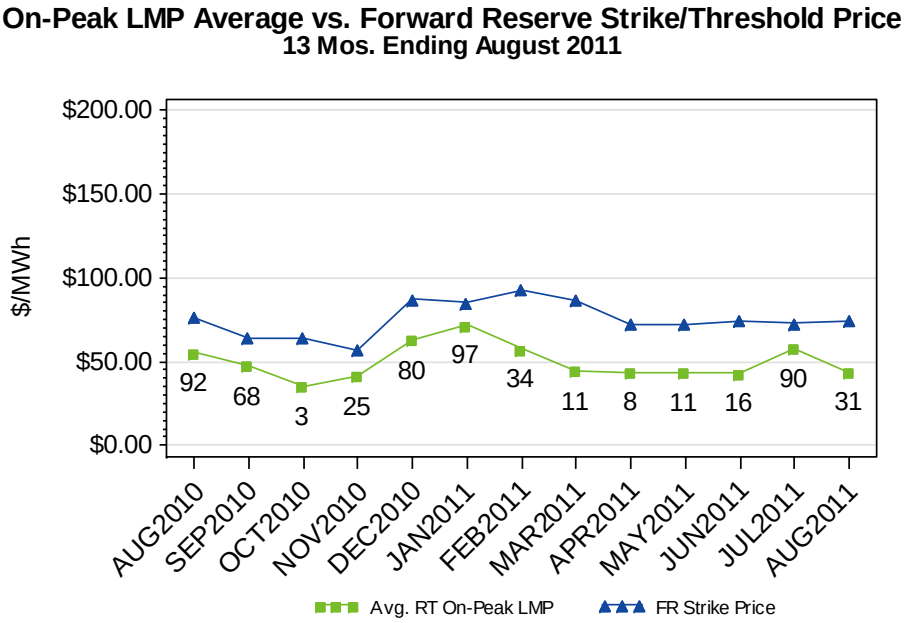
The ISO allocates Forward Reserve Credits, net of Forward Reserve Failure-to-Reserve Penalties and Forward Reserve Failure-to-Activate Penalties, to each Load Zone. The Forward Reserve charge allocation method changed on June 1, 2011. Under the new Forward Reserve Cost Allocation, the Forward Reserves 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.

9.2.2 FRM Charge Summary by Load Zone, August 2011

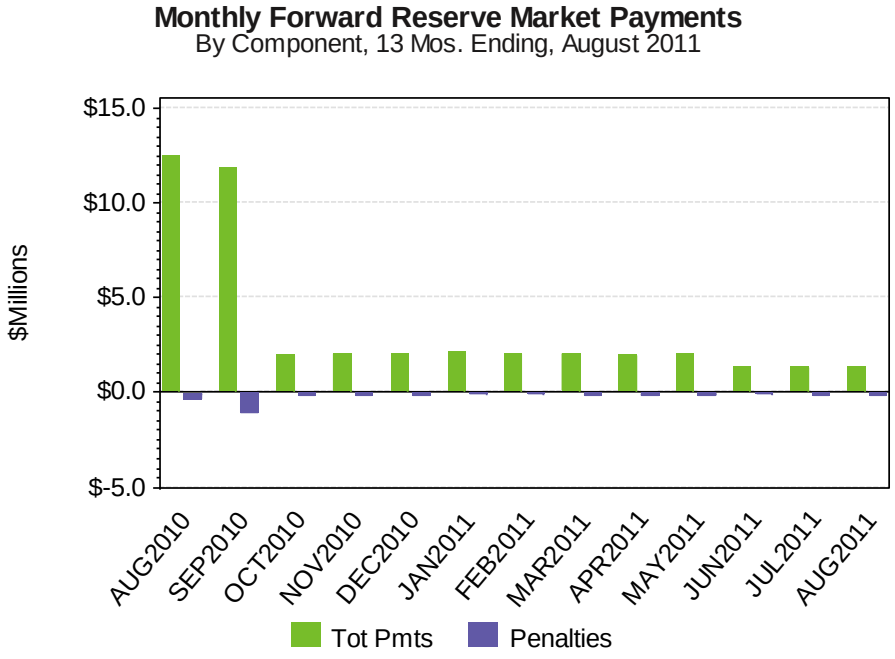
Load Zone	FRM Charge
ME	$100,293
NH	$108,284
VT	$50,615
CT	$298,169
RI	$82,218
SEMA	$152,043
WCMA	$165,809
NEMA	$246,515
ALL	$1,203,946

9.3 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

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



9.5 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 20 separate hours. On a reserve zone basis, non-zero prices occurred thus: CT-20 hours; NEMABSTN-20 hours; ROS-20 hours; SWCT-20 hours. The total compensation paid to assets providing real-time reserves during August 2011, and reductions in those payments for the Forward Reserve Obligation Charge are shown in the following table:

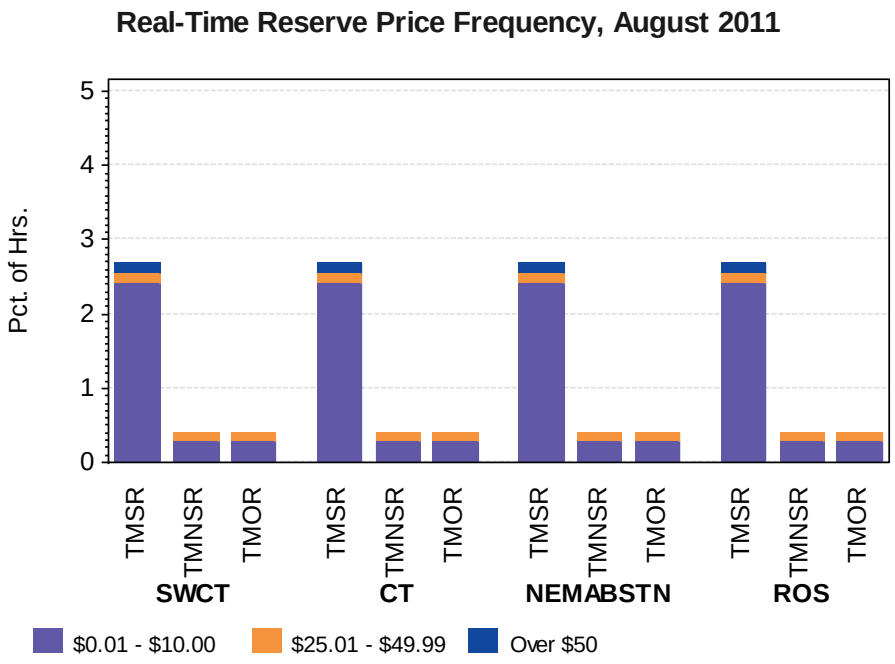
Reserve Zone	Real-Time Reserve Credits	Fwd Reserve Obligation Charges	Net Real-Time Reserve Payments
SYSTEM	$166,109	($1,010)	$165,098
ROS	$135,783	($743)	$135,041
SWCT	$16,432	($15)	$16,417
CT	$10,719	($253)	$10,466
NEMABSTN	$3,174	$0	$3,174

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	$7,285
ME	TMNSR	$4,486
ME	TMOR	$906
ME	ALL	$12,677
NH	TMSR	$8,515
NH	TMNSR	$5,310
NH	TMOR	$1,072
NH	ALL	$14,898
VT	TMSR	$3,824
VT	TMNSR	$2,445
VT	TMOR	$493
VT	ALL	$6,763
CT	TMSR	$24,642
CT	TMNSR	$15,936
CT	TMOR	$3,215
CT	ALL	$43,794
RI	TMSR	$6,457

Load Zone	Reserve Product	RT Reserve Charge
RI	TMNSR	$3,838
RI	TMOR	$778
RI	ALL	$11,072
SEMA	TMSR	$11,979
SEMA	TMNSR	$7,108
SEMA	TMOR	$1,441
SEMA	ALL	$20,528
WCMA	TMSR	$13,075
WCMA	TMNSR	$8,191
WCMA	TMOR	$1,653
WCMA	ALL	$22,919
NEMA	TMSR	$18,902
NEMA	TMNSR	$11,265
NEMA	TMOR	$2,281
NEMA	ALL	$32,447

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.



9.6 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 at:
http://www.iso-ne.com/regulatory/tariff/sect_3/index.html

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 at:
http://www.iso-ne.com/regulatory/tariff/sect_3/index.html

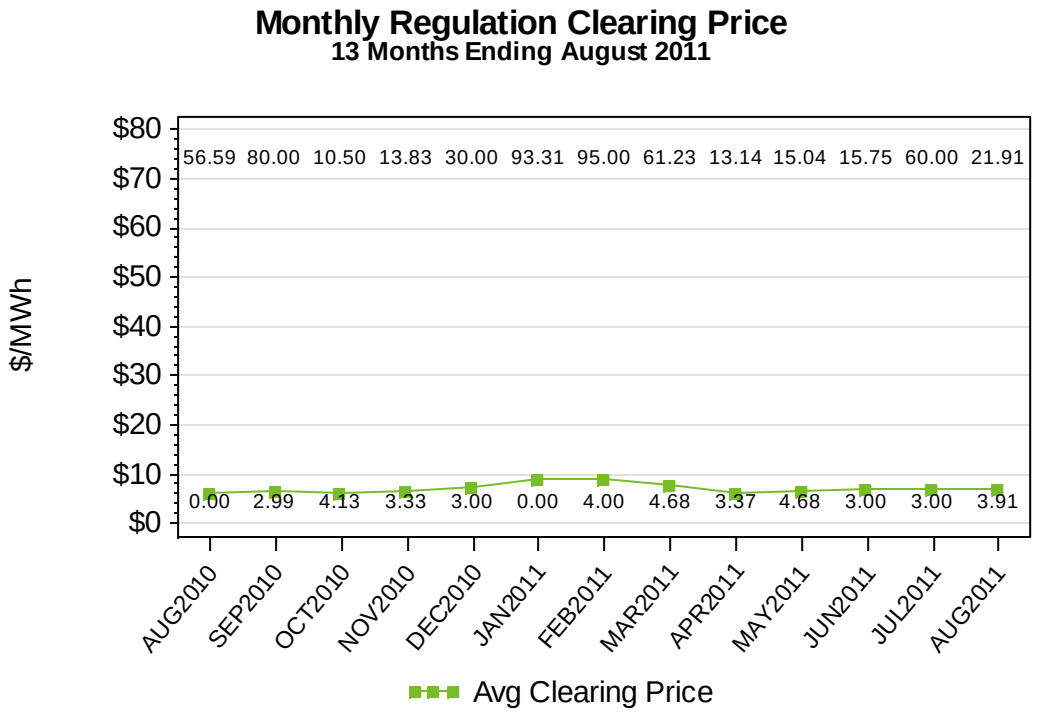
The business rules and procedures for forward and real-time reserve can be found in the ISO’s Manual 28 –Market Rule 1 Accounting located at:
http://www.iso-ne.com/rules_proceds/isone_mnls/index.html

Information about the monthly forward reserve auctions and assumptions can be found on the ISO’s web site at:
http://www.iso-ne.com/markets/othrmkts_data/res_mkt/index.html

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

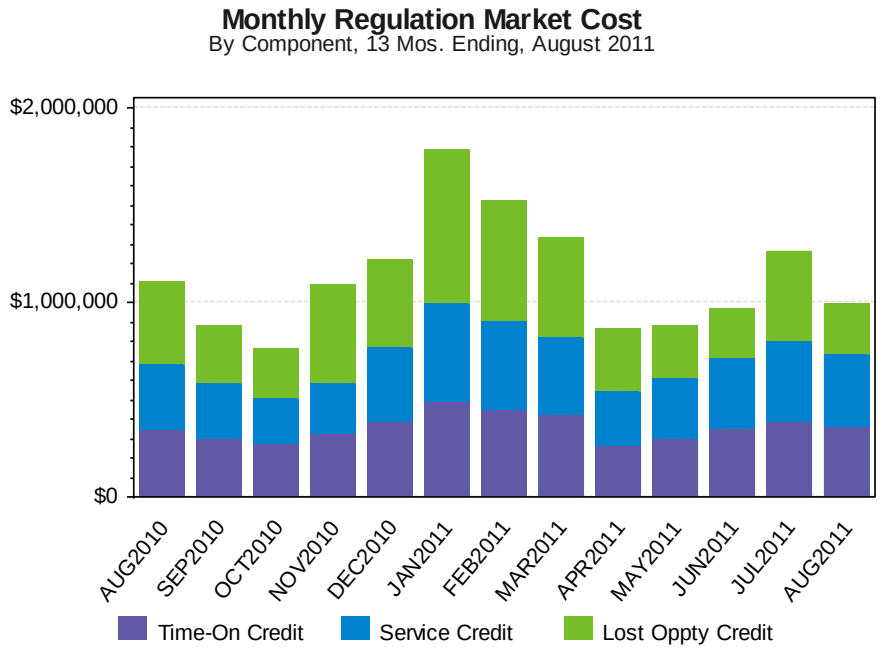
10.2 Monthly Regulation Market Clearing Price Statistics, Last 13 Months

Month	On-Peak Clearing Price Statistics			
	Mean	Max	Min	StdDev
Aug-10	$7.06	$56.59	$0.00	$5.46
Sep-10	$7.06	$80.00	$2.99	$6.99
Oct-10	$6.64	$10.50	$4.67	$1.05
Nov-10	$6.21	$13.83	$3.33	$1.75
Dec-10	$6.93	$30.00	$4.31	$2.89
Jan-11	$8.29	$45.00	$0.00	$5.61
Feb-11	$9.16	$80.91	$4.00	$7.38
Mar-11	$7.94	$61.23	$4.68	$3.90
Apr-11	$6.24	$13.14	$3.37	$1.56

Month	On-Peak Clearing Price Statistics			
	Mean	Max	Min	StdDev
May-11	$6.94	$15.04	$4.68	$1.85
Jun-11	$7.18	$15.75	$4.66	$2.04
Jul-11	$7.78	$60.00	$5.01	$5.23
Aug-11	$7.01	$20.16	$3.91	$2.20

Month	Off-Peak Clearing Price Statistics			
	Mean	Max	Min	StdDev
Aug-10	$5.52	$11.01	$3.00	$0.98
Sep-10	$6.17	$9.33	$3.35	$0.62
Oct-10	$6.00	$10.00	$4.13	$1.06
Nov-10	$6.74	$12.50	$3.33	$1.85
Dec-10	$7.88	$26.74	$3.00	$2.94
Jan-11	$9.87	$93.31	$3.00	$7.38
Feb-11	$9.12	$95.00	$5.11	$7.18
Mar-11	$7.63	$15.85	$5.01	$1.78
Apr-11	$6.11	$9.17	$4.92	$0.92
May-11	$6.25	$13.22	$5.01	$1.17
Jun-11	$6.83	$14.28	$3.00	$1.22
Jul-11	$6.59	$34.75	$3.00	$2.45
Aug-11	$6.88	$21.91	$4.00	$1.59

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
Aug-10	$338,230	$430,676	$342,459	$1,111,365
Sep-10	$300,094	$295,435	$282,063	$877,592
Oct-10	$274,978	$250,028	$230,064	$755,070
Nov-10	$324,708	$505,593	$262,309	$1,092,610
Dec-10	$385,016	$451,426	$380,484	$1,216,926
Jan-11	$487,386	$797,319	$505,604	$1,790,308
Feb-11	$448,417	$616,249	$457,267	$1,521,934
Mar-11	$416,972	$510,102	$402,535	$1,329,610
Apr-11	$264,664	$328,040	$273,244	$865,948
May-11	$301,117	$275,518	$306,575	$883,210
Jun-11	$347,693	$259,507	$364,049	$971,249
Jul-11	$389,431	$466,227	$409,460	$1,265,119
Aug-11	$357,213	$257,055	$376,748	$991,016

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 at:
http://www.iso-ne.com/regulatory/tariff/sect_3/index.html

The business rules and procedures for the Regulation Market can be found in the ISO's Manual 11 – Market Operations located at:
http://www.iso-ne.com/rules_proceds/isone_mnls/index.html

Information about current regulation clearing prices can be found on the ISO's web site at:
http://www.iso-ne.com/markets/hrly_data/res/hourlyRES.do

Selectable hourly historical regulation clearing prices can be found on the ISO's web site at:
http://www.iso-ne.com/markets/hst_rpts/hstRpts.do?category=Hourly

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 August 2011

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
Aug-10	$10,837,050	-$575,939	-$18,408,215	-$929,572	$145,529	$0	$7,571,165	$1,359,983	$8,931,148
Sep-10	$7,523,863	-$44,979	-$13,546,782	-$805,524	-$77,502	$0	$6,022,919	$928,005	$6,950,923
Oct-10	$5,637,832	$277,452	-$9,855,950	-$436,559	-$96,137	$0	$4,218,118	$255,244	$4,473,362
Nov-10	$6,648,999	$348,500	-$10,821,045	-$729,844	-$466,457	$0	$4,172,046	$847,801	$5,019,847
Dec-10	$11,803,801	$354,043	-$19,077,228	-$1,580,861	-$23,702	$0	$7,273,426	$1,250,520	$8,523,947
Jan-11	$12,244,859	$1,914,340	-$21,447,730	-$1,330,883	$153,084	$0	$9,202,872	-$736,540	$8,466,331
Feb-11	$8,274,472	$1,585,313	-$14,674,081	-$751,610	$511,937	$0	$6,399,609	-$1,345,640	$5,053,970
Mar-11	$7,513,684	$1,059,892	-$13,023,982	-$579,560	$573,400	$0	$5,510,298	-$1,053,732	$4,456,566
Apr-11	$5,640,909	$134,766	-$9,626,866	-$684,496	$1,010,966	$0	$3,985,957	-$461,235	$3,524,722
May-11	$5,993,833	$566,856	-$10,919,728	-$808,538	$726,130	$0	$4,925,894	-$484,448	$4,441,446
Jun-11	$8,032,971	$576,761	-$13,592,447	-$756,763	$541,558	$0	$5,559,476	-$361,556	$5,197,920
Jul-11	$11,775,447	$904,535	-$22,409,017	-$1,778,756	$343,124	$0	$10,633,570	$531,096	$11,164,666
Aug-11	$8,371,799	$916,396	-$15,806,648	-$601,836	$562,416	$0	$7,434,849	-$876,976	$6,557,873

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 at:
http://www.iso-ne.com/regulatory/tariff/sect_3/index.html

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

The following table shows the payments made over the last 13 months to generator, demand, and import resources for their capacity during the obligation month. The table shows the initial supply credit paid for the CSO, which can then be adjusted based upon computed values for Peak Energy Rent (PER) and resource performance. PER is a downward adjustment of FCM payments to reflect energy market revenues earned during high priced hours. The supply credit can also be impacted by ISO participation in reconfiguration auctions: sale of excess CSO will reduce the supply credit, while purchase of additional CSO will increase the supply credit. Additional penalties and credits can be charged or earned based on resource availability during shortage events (generator and import resources), or for performance during dispatch events and performance hours (demand resources). The supply credit is adjusted by PER and excess penalties to DR, resulting in the pool of money which will be used to calculate the Net Regional Clearing Price (NRCP Credit in the table below). Additional credits may be earned by resources retained for reliability. The charges associated with these reliability credits are allocated to Network Load.

Month	Capacity Zone	CSO MW (A)	Supply Credit	PER Adjustment	Excess DR Penalties	NRCP Credit	Reliability Credit	Total Payment
Aug-10	Rest-of-Pool	32,704	$137,115,382	-$14,125,533	$0	$122,989,850	$282,690	$123,272,540
Sep-10	Rest-of-Pool	32,704	$137,115,382	-$16,598,236	$0	$120,517,147	$282,690	$120,799,837
Oct-10	Rest-of-Pool	32,853	$137,760,209	-$19,017,941	$0	$118,742,267	$282,690	$119,024,957
Nov-10	Rest-of-Pool	32,850	$137,751,864	-$18,278,258	$0	$119,473,606	$282,690	$119,756,296
Dec-10	Rest-of-Pool	32,909	$137,718,375	-$18,020,748	$0	$119,697,627	$282,690	$119,980,317
Jan-11	Rest-of-Pool	32,883	$137,610,188	-$17,623,453	$0	$119,986,735	$282,690	$120,269,425
Feb-11	Rest-of-Pool	32,883	$137,609,093	-$17,181,012	$0	$120,428,082	$282,690	$120,710,772
Mar-11	Rest-of-Pool	32,814	$137,608,136	-$16,790,839	$0	$120,817,297	$282,690	$121,099,987
Apr-11	Rest-of-Pool	32,818	$137,625,290	-$16,336,232	$0	$121,289,058	$282,690	$121,571,748
May-11	Rest-of-Pool	32,818	$137,625,290	-$16,325,239	$0	$121,300,051	$282,690	$121,582,741
Jun-11	Rest-of-Pool	33,322	$110,998,222	-$14,042,658	$0	$96,955,564	$0	$96,955,564
Jul-11	Rest-of-Pool	33,322	$110,998,222	-$12,131,439	$0	$98,866,783	$0	$98,866,783
Aug-11	Rest-of-Pool	33,322	$110,998,222	-$7,936,773	$0	$103,061,449	$0	$103,061,449

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 Capacity Load Obligation (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. It is worth noting that any customer, not just LSEs, can take on or shed a 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 Net Regional Clearing Price (NRCP).

The following table provides details on FCM charges to load.

Month	Capacity Zone	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
Aug-10	Rest-of-Pool	32,704	1,427	1,400	275	1,593	33,829	24,708	30,836	$3.988496	$122,989,850
Sep-10	Rest-of-Pool	32,704	1,427	1,400	275	1,593	33,829	24,708	30,836	$3.908308	$120,517,147
Oct-10	Rest-of-Pool	32,853	1,440	1,400	275	1,593	33,978	24,708	30,985	$3.832235	$118,742,267
Nov-10	Rest-of-Pool	32,850	1,440	1,400	272	1,593	33,978	24,708	30,985	$3.855845	$119,473,606
Dec-10	Rest-of-Pool	32,909	1,440	0	182	1,661	32,727	24,708	31,066	$3.853060	$119,697,627
Jan-11	Rest-of-Pool	32,883	1,490	0	181	1,661	32,702	24,708	31,041	$3.865422	$119,986,735
Feb-11	Rest-of-Pool	32,883	2,440	0	180	1,661	32,702	24,708	31,041	$3.879640	$120,428,082
Mar-11	Rest-of-Pool	32,814	2,156	1,400	180	1,593	34,034	24,708	31,041	$3.892179	$120,817,297
Apr-11	Rest-of-Pool	32,818	2,156	1,400	264	1,593	33,954	24,708	30,961	$3.917540	$121,289,058
May-11	Rest-of-Pool	32,818	2,206	1,400	264	1,593	33,954	24,708	30,961	$3.917896	$121,300,051
Jun-11	Rest-of-Pool	33,322	2,186	911	67	1,696	34,166	26,701	31,560	$3.072127	$96,955,564
Jul-11	Rest-of-Pool	33,322	2,196	911	67	1,696	34,166	26,701	31,560	$3.132686	$98,866,783
Aug-11	Rest-of-Pool	33,322	2,196	911	67	1,696	34,166	26,701	31,560	$3.265598	$103,061,449

12.2 PER Adjustment

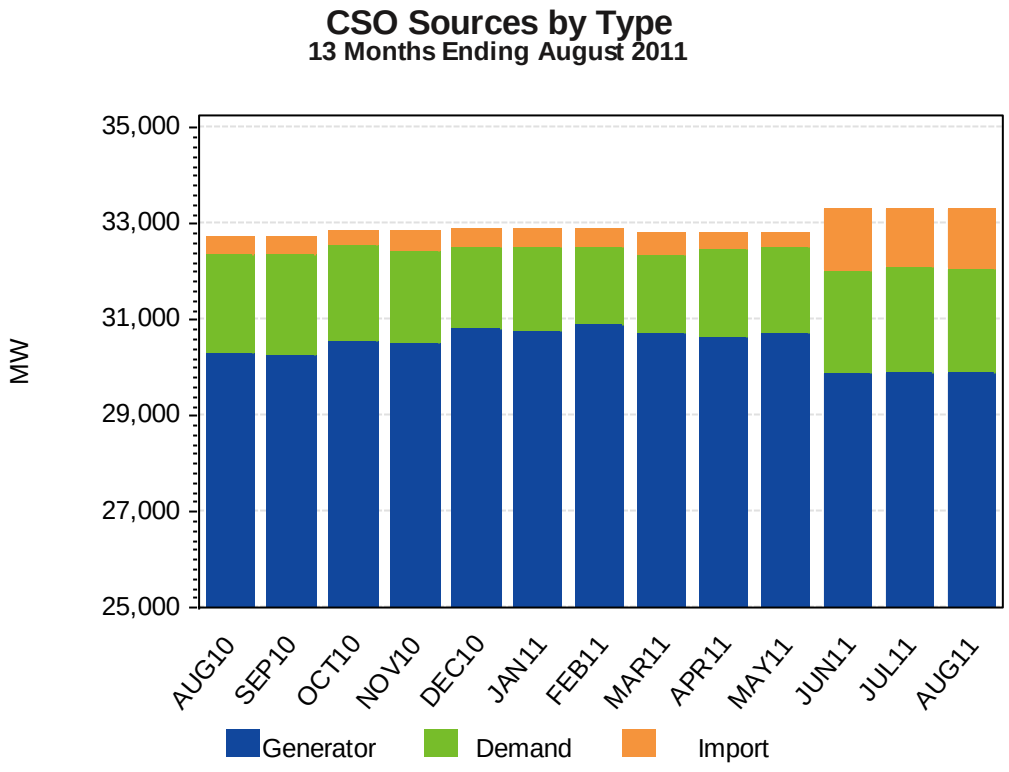
As stated above, Peak Energy Rent is a payment adjustment made to reflect revenues earned by resources during high priced hours in the Energy markets. Generation and Import resources with a CSO are subject to PER adjustments (excluding self-supply CSO MWs). Demand resources are not subject to PER adjustments.

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
Aug-10	Rest-of-Pool	29,065	0.486	$14,125,533
Sep-10	Rest-of-Pool	29,069	0.571	$16,598,236
Oct-10	Rest-of-Pool	29,258	0.650	$19,017,941
Nov-10	Rest-of-Pool	29,339	0.623	$18,278,258
Dec-10	Rest-of-Pool	29,542	0.610	$18,020,748
Jan-11	Rest-of-Pool	29,471	0.598	$17,623,453
Feb-11	Rest-of-Pool	29,622	0.580	$17,181,012
Mar-11	Rest-of-Pool	29,613	0.567	$16,790,839
Apr-11	Rest-of-Pool	29,435	0.555	$16,336,232
May-11	Rest-of-Pool	29,415	0.555	$16,325,239
Jun-11	Rest-of-Pool	29,501	0.476	$14,042,658
Jul-11	Rest-of-Pool	29,445	0.412	$12,131,439
Aug-11	Rest-of-Pool	29,505	0.269	$7,936,773

12.3 Sources of Capacity

The following graph shows, in MW, the amount of capacity procured by type in New England since June 2010 under FCM. The subsequent table displays the data underlying the graph.



Month	Demand Resource MW	Generation MW	Import MW	Total MW
Aug-10	2,063	30,292	349	32,704
Sep-10	2,059	30,277	368	32,704
Oct-10	2,016	30,537	300	32,853
Nov-10	1,923	30,503	424	32,850
Dec-10	1,712	30,810	387	32,909
Jan-11	1,760	30,756	368	32,883
Feb-11	1,608	30,888	387	32,883
Mar-11	1,617	30,731	467	32,814
Apr-11	1,809	30,649	360	32,818
May-11	1,819	30,707	293	32,818
Jun-11	2,149	29,885	1,289	33,322
Jul-11	2,205	29,894	1,223	33,322
Aug-11	2,152	29,889	1,281	33,322

12.4 Capacity Imports

The following table shows the monthly CSO MW resulting from imports since August 2010.

Month	Capacity Zone	NY AC Ties	New Brunswick	HQ Phase I/II	HQ Highgate	Total
Aug-10	Rest-of-Pool	123	26	0	200	349
Sep-10	Rest-of-Pool	142	26	0	200	368
Oct-10	Rest-of-Pool	100	0	0	200	300
Nov-10	Rest-of-Pool	224	0	0	200	424
Dec-10	Rest-of-Pool	119	0	68	200	387
Jan-11	Rest-of-Pool	100	0	68	200	368
Feb-11	Rest-of-Pool	119	0	68	200	387
Mar-11	Rest-of-Pool	267	0	0	200	467
Apr-11	Rest-of-Pool	160	0	0	200	360
May-11	Rest-of-Pool	93	0	0	200	293
Jun-11	Rest-of-Pool	343	284	462	200	1,289
Jul-11	Rest-of-Pool	277	284	462	200	1,223
Aug-11	Rest-of-Pool	335	284	462	200	1,281

12.5 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.

12.5.1 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
Aug-10	0	0.00	Generator	0	0	$0
Aug-10	0	0.00	Import	0	0	$0
Sep-10	0	0.00	Generator	0	0	$0
Sep-10	0	0.00	Import	0	0	$0
Oct-10	0	0.00	Generator	0	0	$0
Oct-10	0	0.00	Import	0	0	$0
Nov-10	0	0.00	Generator	0	0	$0
Nov-10	0	0.00	Import	0	0	$0
Dec-10	0	0.00	Generator	0	0	$0
Dec-10	0	0.00	Import	0	0	$0
Jan-11	0	0.00	Generator	0	0	$0
Jan-11	0	0.00	Import	0	0	$0
Feb-11	0	0.00	Generator	0	0	$0
Feb-11	0	0.00	Import	0	0	$0
Mar-11	0	0.00	Generator	0	0	$0
Mar-11	0	0.00	Import	0	0	$0
Apr-11	0	0.00	Generator	0	0	$0
Apr-11	0	0.00	Import	0	0	$0
May-11	0	0.00	Generator	0	0	$0
May-11	0	0.00	Import	0	0	$0
Jun-11	0	0.00	Generator	0	0	$0
Jun-11	0	0.00	Import	0	0	$0
Jul-11	0	0.00	Generator	0	0	$0
Jul-11	0	0.00	Import	0	0	$0
Aug-11	0	0.00	Generator	0	0	$0
Aug-11	0	0.00	Import	0	0	$0

12.5.2 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 ($)	Performance Incentive ($)
Aug-10	ON_PEAK	88	491.41	614.49	-4.08	127.16	-$17,335	$419,728
Aug-10	REAL_TIME	0	804.84	790.53	-141.75	127.45	-$603,013	$420,695
Aug-10	REAL_TIME_EG	0	620.87	452.19	-178.67	9.98	-$521,353	$22,604
Aug-10	SEASONAL_PEAK	53	145.67	230.09	0.00	84.42	$0	$278,674
Sep-10	ON_PEAK	0	493.32	611.87	-5.90	124.46	-$25,103	$447,439
Sep-10	REAL_TIME	0	811.40	778.39	-133.19	100.17	-$566,573	$360,137
Sep-10	REAL_TIME_EG	0	608.60	443.95	-175.44	10.79	-$511,925	$26,607
Sep-10	SEASONAL_PEAK	0	145.67	220.61	0.00	74.94	$0	$269,419
Oct-10	ON_PEAK	0	491.14	611.85	-3.68	124.38	-$15,633	$389,707
Oct-10	REAL_TIME	0	789.23	778.17	-118.76	107.70	-$505,205	$337,436
Oct-10	REAL_TIME_EG	0	590.07	442.44	-161.02	13.38	-$469,859	$28,760
Oct-10	SEASONAL_PEAK	0	145.67	220.61	0.00	74.94	$0	$234,795
Nov-10	ON_PEAK	0	490.01	611.85	-3.21	125.05	-$13,643	$261,267
Nov-10	REAL_TIME	0	741.82	773.88	-71.41	103.47	-$303,765	$216,191
Nov-10	REAL_TIME_EG	0	545.43	442.44	-113.82	10.83	-$332,138	$15,514
Nov-10	SEASONAL_PEAK	0	145.67	220.61	0.00	74.94	$0	$156,574
Dec-10	ON_PEAK	42	489.39	855.92	-5.97	372.50	-$25,396	$610,030
Dec-10	REAL_TIME	0	620.14	557.68	-184.73	122.27	-$785,841	$200,241
Dec-10	REAL_TIME_EG	0	457.14	381.64	-124.43	48.93	-$363,093	$54,969
Dec-10	SEASONAL_PEAK	99	145.67	334.41	0.00	188.74	$0	$309,090

Month	DR Type	Performance Hours	CSO MW	Capacity Value (MW)	Negative Capacity Variance (MW)	Positive Capacity Variance (MW)	Performance Penalty ($)	Performance Incentive ($)
Jan-11	ON_PEAK	42	489.39	898.29	-5.86	414.75	-$24,916	$607,006
Jan-11	REAL_TIME	0	672.42	596.34	-208.85	132.77	-$888,435	$194,307
Jan-11	REAL_TIME_EG	0	452.29	426.96	-87.07	61.74	-$254,076	$61,977
Jan-11	SEASONAL_PEAK	142	145.67	353.48	0.00	207.81	$0	$304,137
Feb-11	ON_PEAK	0	489.39	877.59	-5.64	393.84	-$23,993	$345,809
Feb-11	REAL_TIME	0	536.43	581.29	-94.12	138.99	-$400,399	$122,038
Feb-11	REAL_TIME_EG	0	436.49	404.20	-85.55	53.26	-$249,623	$32,075
Feb-11	SEASONAL_PEAK	0	145.67	343.94	0.00	198.27	$0	$174,093
Mar-11	ON_PEAK	0	488.15	877.59	-4.48	393.93	-$19,066	$290,567
Mar-11	REAL_TIME	0	533.50	581.54	-71.73	119.77	-$305,144	$88,347
Mar-11	REAL_TIME_EG	0	449.23	404.20	-73.87	28.84	-$215,544	$14,590
Mar-11	SEASONAL_PEAK	0	145.67	343.94	0.00	198.27	$0	$146,250
Apr-11	ON_PEAK	0	493.33	611.87	-5.19	123.73	-$22,070	$114,176
Apr-11	REAL_TIME	0	678.67	771.63	-21.06	114.02	-$89,602	$105,217
Apr-11	REAL_TIME_EG	0	491.69	442.50	-63.78	14.60	-$186,113	$9,240
Apr-11	SEASONAL_PEAK	0	145.67	220.61	0.00	74.94	$0	$69,152
May-11	ON_PEAK	0	492.10	598.65	-2.83	109.38	-$12,030	$135,785
May-11	REAL_TIME	0	691.11	819.04	-41.90	169.83	-$178,230	$210,831
May-11	REAL_TIME_EG	0	490.11	426.53	-88.06	24.48	-$256,953	$20,845
May-11	SEASONAL_PEAK	0	145.67	209.91	0.00	64.24	$0	$79,752
Jun-11	ON_PEAK	88	617.02	935.40	-9.21	327.59	-$29,791	$236,856
Jun-11	REAL_TIME	0	780.24	887.07	-41.71	148.50	-$130,268	$100,999
Jun-11	REAL_TIME_EG	0	491.84	482.03	-37.06	27.25	-$91,432	$14,661
Jun-11	SEASONAL_PEAK	0	259.66	234.20	-34.32	8.86	-$107,053	$6,028
Jul-11	ON_PEAK	80	617.49	943.96	-7.20	333.67	-$25,279	$446,180
Jul-11	REAL_TIME	6	812.01	725.32	-115.50	28.76	-$360,236	$36,142
Jul-11	REAL_TIME_EG	0	515.76	447.11	-85.07	16.42	-$209,875	$16,298
Jul-11	SEASONAL_PEAK	34	259.66	337.20	-0.28	77.83	-$876	$97,647
Aug-11	ON_PEAK	92	617.86	989.95	-11.03	383.12	-$40,602	$341,086
Aug-11	REAL_TIME	0	738.33	746.51	-57.87	65.99	-$180,532	$55,634
Aug-11	REAL_TIME_EG	0	536.18	446.90	-100.43	11.16	-$247,771	$7,442
Aug-11	SEASONAL_PEAK	0	259.66	337.20	-0.28	77.83	-$876	$65,618

12.6 For More Information

Detailed information on the FCM, including information on the qualification process, auction results, and FERC filings and orders can be found at:
http://www.iso-ne.com/markets/othrmkts_data/fcm/

13. Energy Market Payments to Demand Assets

As of June 2010, a portion of Demand Response related payments are made in the form of capactiy payments to Demand Resources from the Forward Capacity Market. However, ISO-NE continues to allow any Market Participant to enroll their Load Response Program assets in the Energy Market through two programs: the Day-Ahead Load Response Program and the Real-Time Price Response Program. These two programs are defined 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
Jul-10	13,964.80	16,634.66	$1,678,325	0.00	0.00	$0	DRP
Aug-10	11,473.80	14,574.03	$1,286,528	0.00	0.00	$0	DRP
Sep-10	12,108.80	9,487.31	$626,639	0.00	0.00	$0	DRP
Oct-10	348.00	401.57	$20,645	0.00	0.00	$0	DRP
Nov-10	15,291.90	21,362.99	$1,040,059	0.00	0.00	$0	DRP
Dec-10	9,991.90	15,957.30	$1,465,706	0.00	0.00	$0	DRP
Jan-11	11,500.90	17,920.72	$1,707,458	14.40	68.46	$6,774	DRP
Feb-11	6,116.30	10,017.34	$868,276	6.50	34.41	$2,880	DRP
Mar-11	1,965.20	1,687.91	$132,807	0.00	0.00	$0	DRP
Apr-11	3,874.50	1,544.05	$91,830	0.00	0.00	$0	DRP

Latest Available Month	RTDR Assets			Price Response Program			
	Day-Ahead Cleared (MWh)	Actual Real-Time Interruptions (MWh)	DALRP Payments	Day-Ahead Cleared (MWh)	Actual Real-Time Interruptions (MWh)	DALRP Payments	Stlmnt Status
May-11	2,982.10	1,393.17	$82,591	0.00	0.00	$0	Initial
Jun-11	4,702.20	3,454.90	$252,415	0.00	0.00	$0	Initial
Jul-11	12,058.80	17,367.16	$2,078,168	0.00	0.00	$0	Initial

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
Jul-10	1,929.72	$231,957	DRP
Aug-10	1,389.73	$169,513	DRP
Sep-10	799.35	$89,328	DRP
Oct-10	120.01	$12,001	DRP
Nov-10	448.51	$44,851	DRP
Dec-10	299.43	$31,826	DRP
Jan-11	1,322.16	$141,838	DRP
Feb-11	575.28	$58,504	DRP
Mar-11	139.97	$14,429	Initial
Apr-11	51.44	$5,144	Initial
May-11	0.00	$0	Initial
Jun-11	27.65	$2,874	Initial
Jul-11	203.57	$28,425	Initial

14. Document History

Date	Version	Description
9/20/2011	Rev. 1	Updated tables in Section 12.1 and 12.2.
9/16/2011	Original Posting	