Monthly Market Operations Report
December 2011

ISO New England Inc.
Market Analysis and Settlements
January 18, 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 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 cannot 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 $35.85/MWh and $33.89/MWh, respectively, during December 2011. Day-ahead and real-time prices at the Hub and in the Load Zones averaged 2-13% lower than November 2011 averages. In the aggregate, December 2011 day-ahead and real-time LMPs were approximately 46% lower during December 2011 than in December 2010. Average natural gas prices were about 48% below the prior year's average prices, while residual fuel prices were up 27% over a year ago.

Overall, the average of the hourly real-time LMPs at the Hub and in the Load Zones ranged between 5.8% lower than day-ahead in the Vermont (VT) Load Zone to 5.0% lower than its day-ahead counterpart in the Southeastern Massachusetts (SEMA) Load Zone. In the Day-Ahead Market, Load Zone average LMPs ranged between 2.9% lower than the Hub average LMPs in the Maine (ME) Load Zone to 0.5% higher than the Hub in the Western/Central Massachusetts (WCMA) Load Zone. Results were similar in the Real-Time Market, with average LMPs ranging from 3.1% lower than the Hub average LMPs in the ME Load Zone to 0.6% higher than the Hub in the Connecticut (CT) Load Zone. Price differentials between on-peak and off-peak hours at the Hub and in the Load Zones ranged between 21% and 28% 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 December. In the Day-Ahead Energy Market, there were approximately 543,000 MWh of total exports and 1,539,000 MWh of imports, yielding a net import of approximately 997,000 MWh. In the Real-Time Energy Market, there were approximately 628,000 MWh of total exports and 1,674,000 MWh of imports, yielding a net import of approximately 1,046,000 MWh. This was about 428,000 MW higher than a year ago.

The Monthly FTR Auction (December 2011) had 34 participants and the awarded value of FTRs in the auction totaled $577,000. This represented a decline of $35,000 from the previous month and a decrease of about $214,000 from the prior year's monthly FTR auction. The allocation of FTR Auction Revenue for December 2011 resulted in $1.8 million awarded to eligible entities, with $128K allocated to Qualified Upgrade Awards.

The Marginal Loss Revenue Fund totaled $4.2 million for December, up $100,000 from its November 2011 total.

Total Forward Reserve Credits to eligible assets of $1.2 million were reduced by $39,000 in Failure to Reserve Penalties and $0 in Failure to Activate Penalties during December 2011. The net Forward Reserve Payment of $1.1 million represented 94% of the maximum possible payment of $1.2 million. Real-Time Reserve Prices occurred in 72 separate hours during the month, and those yielded real-time payments to designated assets of $584,000. These payments were reduced by Forward Reserve Energy Obligation Charges totaling $105,000 yielding a net compensation of $479,000 during the month.

Regulation Market Payments totaled $900,000 during the month, a decrease of $145,000 from the November 2011 value of $1.0 million.

For the month of December 2011, Forward Capacity payments were made to a total of 33,507 MW of capacity and totaled $112 million.

There are two programs through which load response assets can participate in the Energy Market. Total payments during November 2011 (the latest month available) totaled $60,000 for interruptions associated with the Day Ahead Load Response Program and $2,000 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, December 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	$35.85	$33.89	$20.26	$0.00	$81.40	$277.59	55%	54%	94.5%	$8.45	$13.32	1.58
ME	$34.80	$32.85	$19.63	$0.00	$78.15	$277.50	53%	52%	94.4%	$8.20	$13.19	1.61
NH	$35.36	$33.48	$20.05	$0.00	$79.79	$277.74	54%	53%	94.7%	$8.34	$13.25	1.59
VT	$35.67	$33.59	$20.31	$0.00	$79.22	$271.19	55%	53%	94.2%	$8.21	$12.99	1.58
CT	$35.96	$34.08	$20.04	$0.00	$80.90	$277.18	55%	54%	94.8%	$8.52	$13.40	1.57
RI	$35.49	$33.65	$20.30	$0.00	$80.95	$275.01	54%	53%	94.8%	$8.26	$13.15	1.59
SEMA	$35.68	$33.88	$20.34	$0.00	$82.02	$279.07	55%	54%	95.0%	$8.41	$13.35	1.59
WCMA	$36.04	$34.02	$20.34	$0.00	$81.53	$278.67	55%	54%	94.4%	$8.51	$13.36	1.57
NEMA	$35.74	$33.90	$20.39	$0.00	$81.58	$280.23	55%	54%	94.8%	$8.51	$13.42	1.58
NB Ext	$33.65	$31.87	$18.91	$0.00	$73.96	$276.46	52%	50%	95%	$7.87	$13.06	1.66
NYN Ext	$35.51	$33.40	$19.88	$0.00	$79.00	$268.38	54%	53%	94%	$8.26	$12.92	1.56
HQ Ext	$34.86	$33.09	$20.00	$0.00	$79.15	$272.88	53%	52%	95%	$8.18	$13.01	1.59
HG Ext	$33.35	$31.53	$19.64	$0.00	$73.25	$250.71	51%	50%	95%	$7.36	$11.93	1.62
CSC Ext	$35.96	$34.50	$20.00	$0.00	$80.88	$280.50	55%	55%	96%	$8.50	$13.55	1.59
NNC Ext	$36.03	$34.20	$19.91	$0.00	$80.00	$275.74	55%	54%	95%	$8.51	$13.38	1.57

4.1.2 On-Peak Hours, December 2011

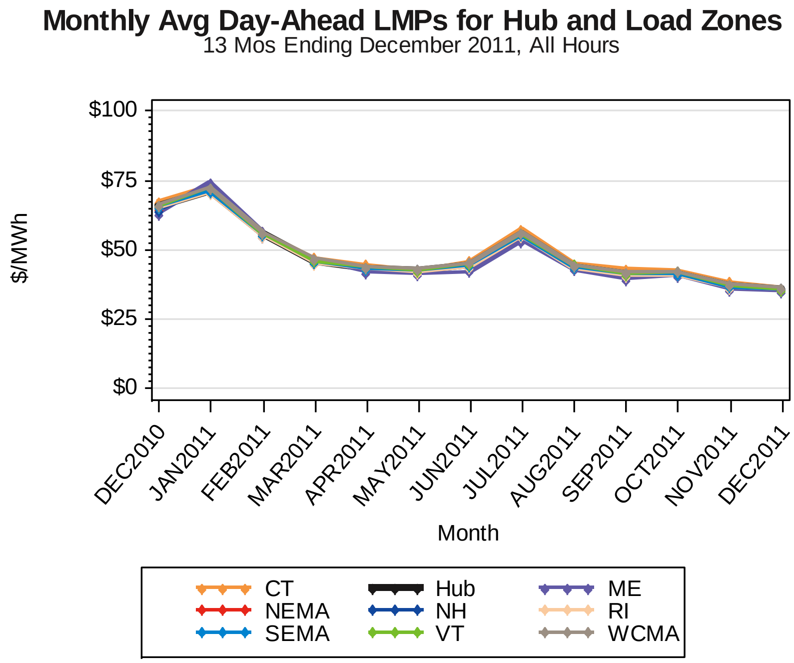
Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$39.91	$38.46	$29.12	$23.66	$81.40	$277.59	55%	55%	96%	$8.77	$16.16	1.84
ME	$38.82	$37.30	$28.29	$22.44	$78.15	$277.50	53%	53%	96%	$8.43	$16.04	1.90
NH	$39.43	$38.01	$28.86	$23.03	$79.79	$277.74	54%	54%	96%	$8.63	$16.09	1.86
VT	$39.66	$38.04	$29.12	$23.32	$79.22	$271.19	54%	54%	96%	$8.52	$15.75	1.85
CT	$40.12	$38.73	$29.00	$23.90	$80.90	$277.18	55%	55%	97%	$8.83	$16.19	1.83
RI	$39.30	$38.03	$28.41	$23.41	$80.95	$275.01	54%	54%	97%	$8.67	$16.00	1.85
SEMA	$39.66	$38.41	$28.64	$23.53	$82.02	$279.07	54%	55%	97%	$8.78	$16.23	1.85
WCMA	$40.15	$38.61	$29.22	$23.72	$81.53	$278.67	55%	55%	96%	$8.82	$16.20	1.84
NEMA	$39.84	$38.50	$29.02	$23.52	$81.58	$280.23	54%	55%	97%	$8.86	$16.31	1.84
NB Ext	$37.47	$36.09	$27.24	$21.31	$73.96	$276.46	51%	52%	96%	$8.10	$15.97	1.97
NYN Ext	$39.55	$37.88	$28.78	$23.54	$79.00	$268.38	54%	54%	96%	$8.58	$15.63	1.82
HQ Ext	$38.78	$37.51	$28.27	$23.03	$79.15	$272.88	53%	54%	97%	$8.51	$15.83	1.86
HG Ext	$36.73	$35.30	$27.10	$21.65	$73.25	$250.71	50%	50%	96%	$7.88	$14.61	1.85
CSC Ext	$40.11	$39.20	$28.99	$24.25	$80.88	$280.50	55%	56%	98%	$8.83	$16.38	1.86
NNC Ext	$40.25	$38.90	$29.13	$24.08	$80.00	$275.74	55%	56%	97%	$8.79	$16.14	1.84

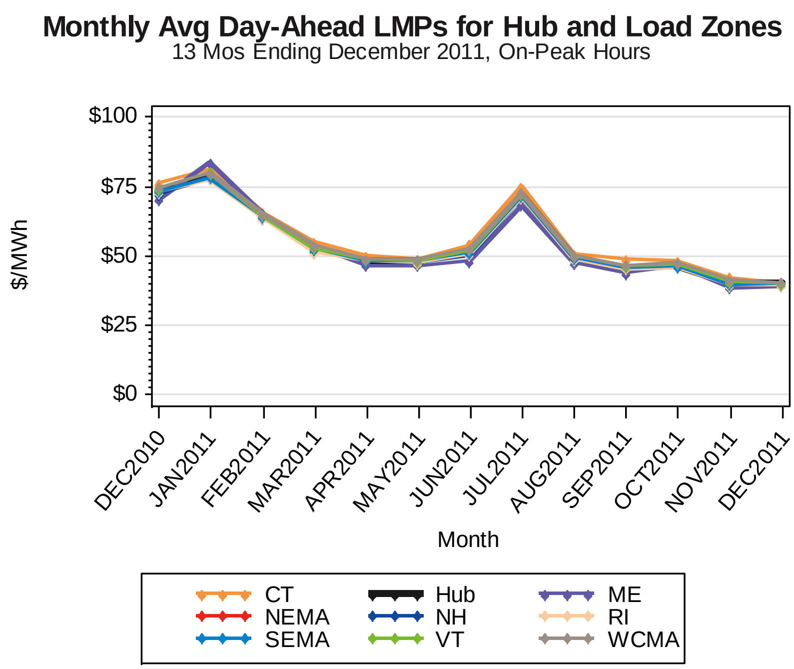
4.1.3 Off-Peak Hours, December 2011

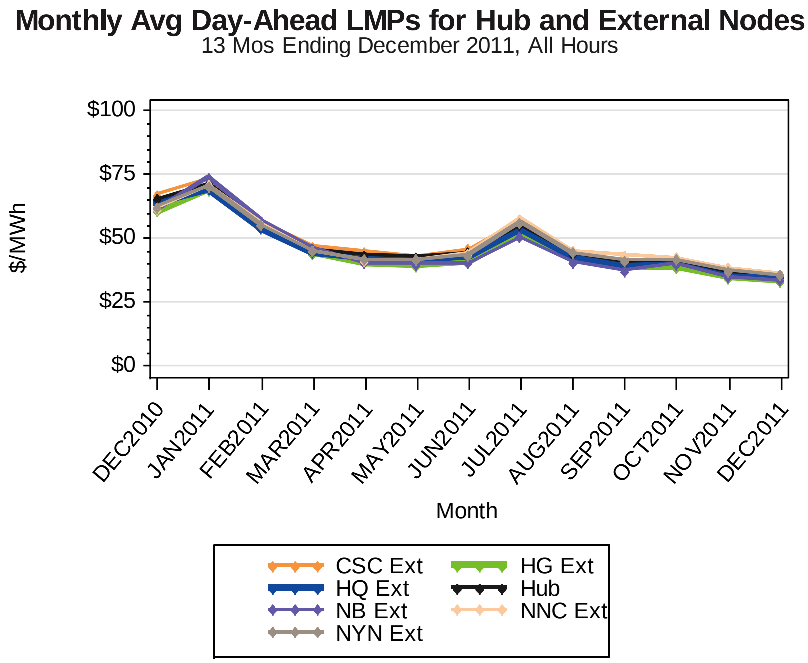
Hub/Zone/ Ext. Node	Avg DA LMP ($/MWh)	Avg RT LMP ($/MWh)	Min DA LMP ($/MWh)	Min RT LMP ($/MWh)	Max DA LMP ($/MWh)	Max RT LMP ($/MWh)	DA % of Hub	RT % of Hub	RT % of DA	DA Std Dev	RT Std Dev	RT Std /DA Std
Hub	$32.51	$30.13	$20.26	$0.00	$66.25	$72.90	56%	53%	93%	$6.50	$8.79	1.35
ME	$31.48	$29.19	$19.63	$0.00	$63.32	$70.20	55%	52%	93%	$6.31	$8.72	1.38
NH	$32.01	$29.75	$20.05	$0.00	$65.28	$71.90	56%	53%	93%	$6.39	$8.75	1.37
VT	$32.39	$29.93	$20.31	$0.00	$64.83	$72.20	56%	53%	92%	$6.26	$8.61	1.38
CT	$32.54	$30.26	$20.04	$0.00	$66.25	$73.68	57%	54%	93%	$6.50	$8.91	1.37
RI	$32.36	$30.04	$20.30	$0.00	$66.02	$72.60	56%	53%	93%	$6.40	$8.72	1.36
SEMA	$32.40	$30.14	$20.34	$0.00	$66.30	$72.72	56%	53%	93%	$6.46	$8.81	1.36
WCMA	$32.66	$30.25	$20.34	$0.00	$66.45	$73.15	57%	54%	93%	$6.53	$8.84	1.35
NEMA	$32.36	$30.11	$20.39	$0.00	$66.35	$72.62	56%	53%	93%	$6.51	$8.83	1.36
NB Ext	$30.51	$28.39	$18.91	$0.00	$60.85	$69.45	53%	50%	93%	$6.10	$8.62	1.41
NYN Ext	$32.18	$29.72	$19.88	$0.00	$64.98	$71.51	56%	53%	92%	$6.27	$8.55	1.37
HQ Ext	$31.64	$29.45	$20.00	$0.00	$64.55	$70.72	55%	52%	93%	$6.28	$8.58	1.37
HG Ext	$30.57	$28.42	$19.64	$0.00	$60.03	$67.64	53%	50%	93%	$5.53	$7.92	1.43
CSC Ext	$32.55	$30.63	$20.00	$0.00	$66.24	$74.59	57%	54%	94%	$6.48	$9.01	1.39
NNC Ext	$32.56	$30.33	$19.91	$0.00	$66.18	$74.02	57%	54%	93%	$6.48	$8.90	1.37

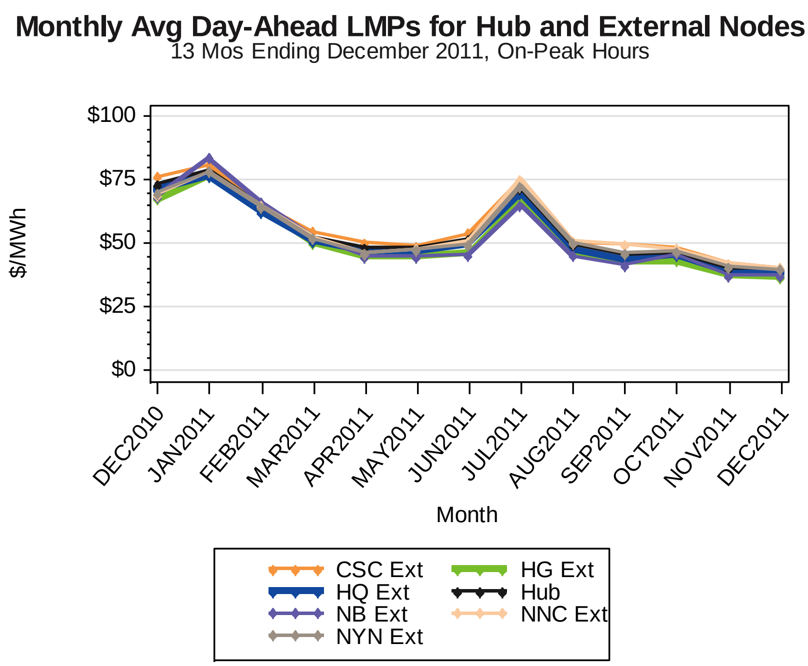
4.2 LMP Graphs, Day-Ahead Market, 13 Months Ending December 2011

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.



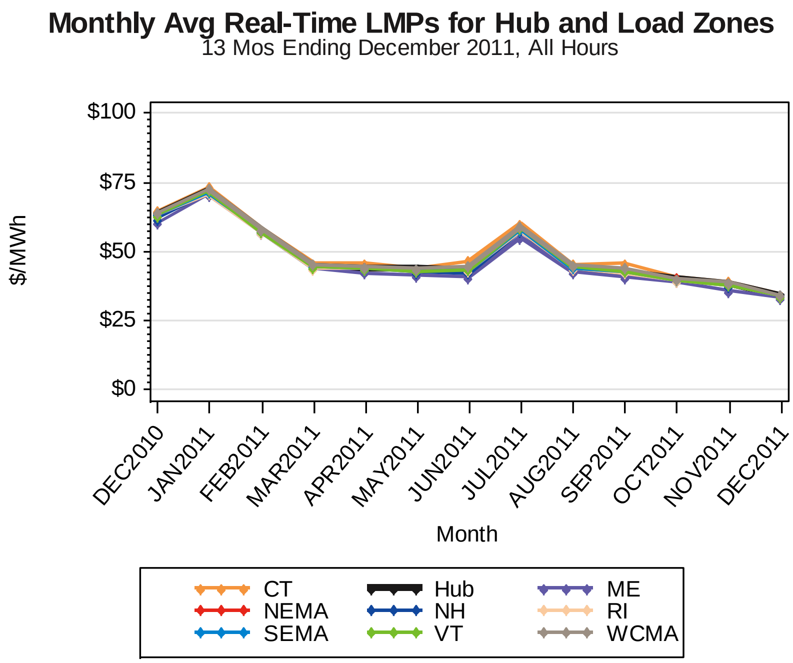


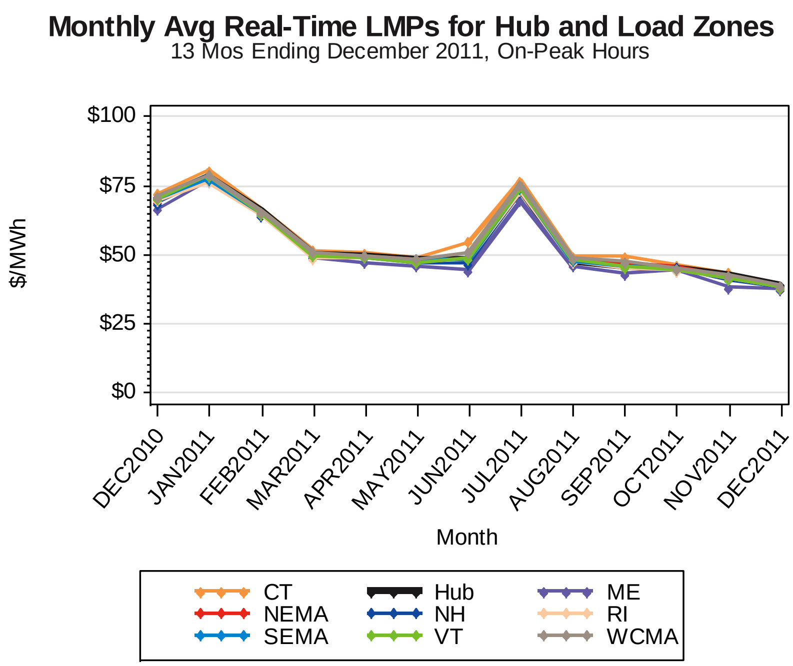

Monthly Avg Day-Ahead LMPs for Hub and External Nodes
13 Mos Ending December 2011, All Hours
$/MWh
$100
$75
$50
$25
$0
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
Month
CSC Ext
HQ Ext
NB Ext
NYN Ext
HG Ext
Hub
NNC Ext

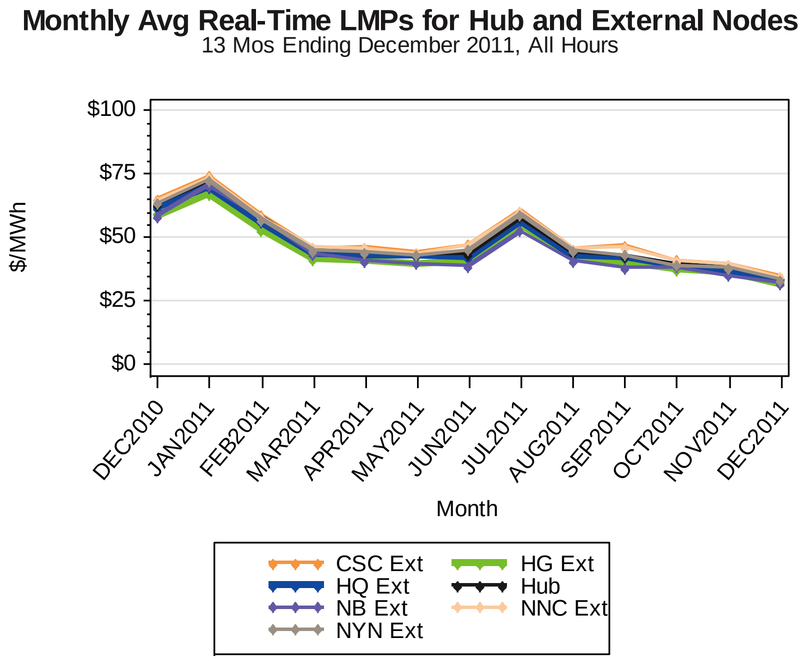

Monthly Avg Day-Ahead LMPs for Hub and External Nodes
13 Mos Ending December 2011, On-Peak Hours
$/MWh
$100
$75
$50
$25
$0
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
Month
CSC Ext
HQ Ext
NB Ext
NYN Ext
HG Ext
Hub
NNC Ext

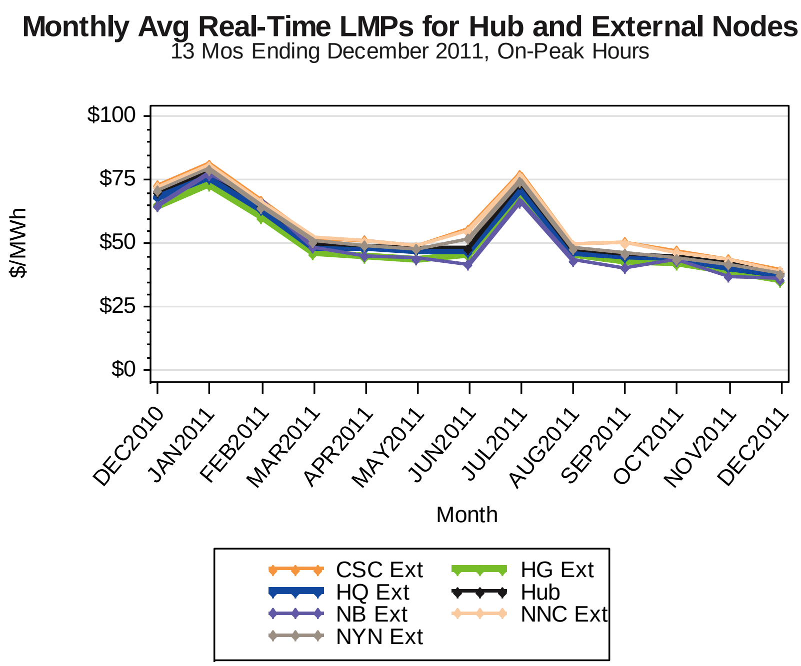
4.3 LMP Graphs, Real-Time Market, 13 Months Ending December 2011

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 December 2011, All Hours
$/MWh
$100
$75
$50
$25
$0
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
Month
CSC Ext
HG Ext
HQ Ext
Hub
NB Ext
NNC Ext
NYN Ext


Monthly Avg Real-Time LMPs for Hub and External Nodes
13 Mos Ending December 2011, On-Peak Hours
$/MWh
$100
$75
$50
$25
$0
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
Month
CSC Ext
HG Ext
HQ Ext
Hub
NB Ext
NNC Ext
NYN Ext

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.

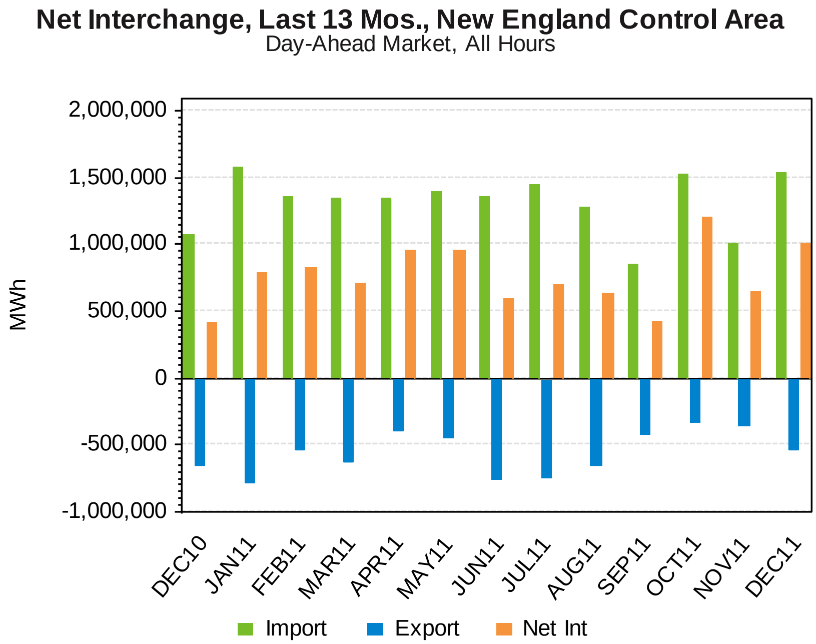
5.1 Net Interchange Summary, December 2011

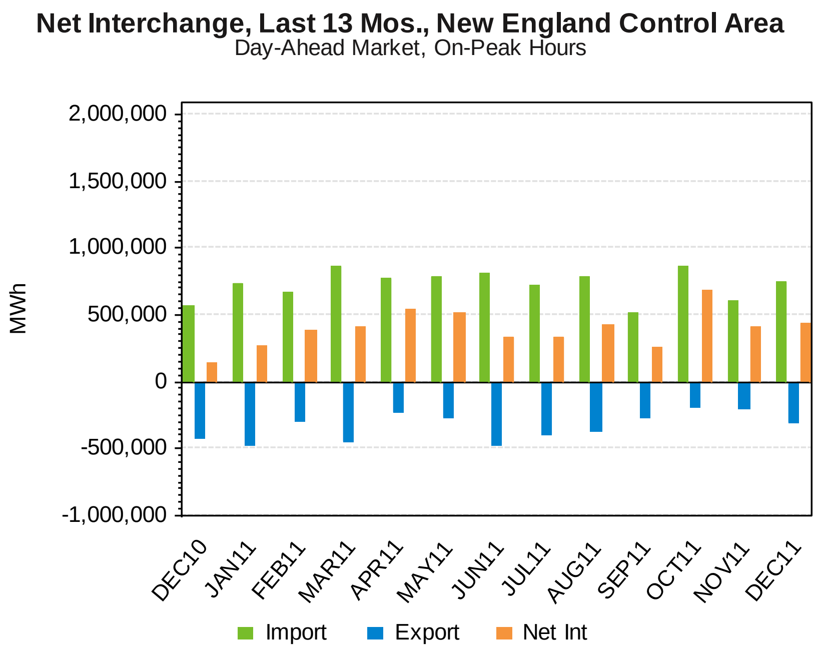
The following tables show summary statistics for imports and exports on the six external interfaces for both the Day-Ahead and Real-Time Markets:

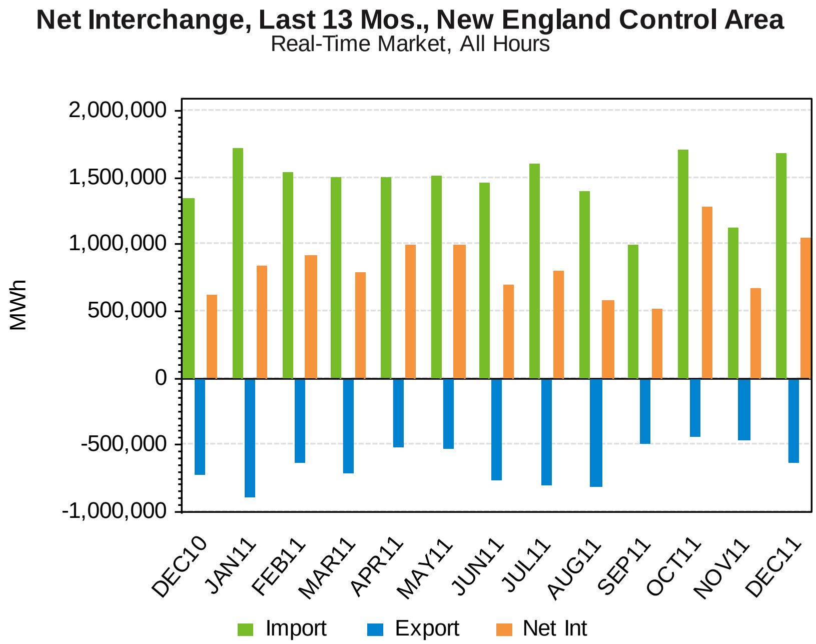
5.1.1 Day-Ahead and Real-Time Market Summary by Interface

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	-102,246	0	-102,246	-110,025	7	-110,018
	NY-CSC	-228,523	0	-228,523	-227,903	0	-227,903
	HQ HG	0	134,147	134,147	0	134,241	134,241
	HQ I/II	0	975,857	975,857	0	1,006,636	1,006,636
	NY-N AC	-168,617	342,943	174,326	-203,000	425,621	222,621
	NB	-43,122	86,494	43,372	-87,338	107,618	20,280
Total	**All Hours**	**-542,508**	**1,539,441**	**996,933**	**-628,266**	**1,674,123**	**1,045,857**
Off-Peak	NNC	-48,938	0	-48,938	-54,178	0	-54,178
	NY-CSC	-118,913	0	-118,913	-118,293	0	-118,293
	HQ HG	0	61,304	61,304	0	61,836	61,836
	HQ I/II	0	513,955	513,955	0	520,928	520,928
	NY-N AC	-49,949	176,613	126,664	-61,979	218,098	156,119
	NB	-18,403	46,901	28,498	-49,037	57,360	8,323
Total	Off-Peak	-236,203	798,773	562,570	-283,487	858,222	574,735
On-Peak	NNC	-53,308	0	-53,308	-55,847	7	-55,840
	NY-CSC	-109,610	0	-109,610	-109,610	0	-109,610
	HQ HG	0	72,843	72,843	0	72,405	72,405
	HQ I/II	0	461,903	461,903	0	485,708	485,708
	NY-N AC	-118,668	166,330	47,662	-141,021	207,523	66,502
	NB	-24,719	39,593	14,874	-38,301	50,258	11,957
Total	On-Peak	-306,305	740,668	434,363	-344,779	815,901	471,122

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
MWh
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
DEC10
JAN11
FEB11
MAR11
APR11
MAY11
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JUL11
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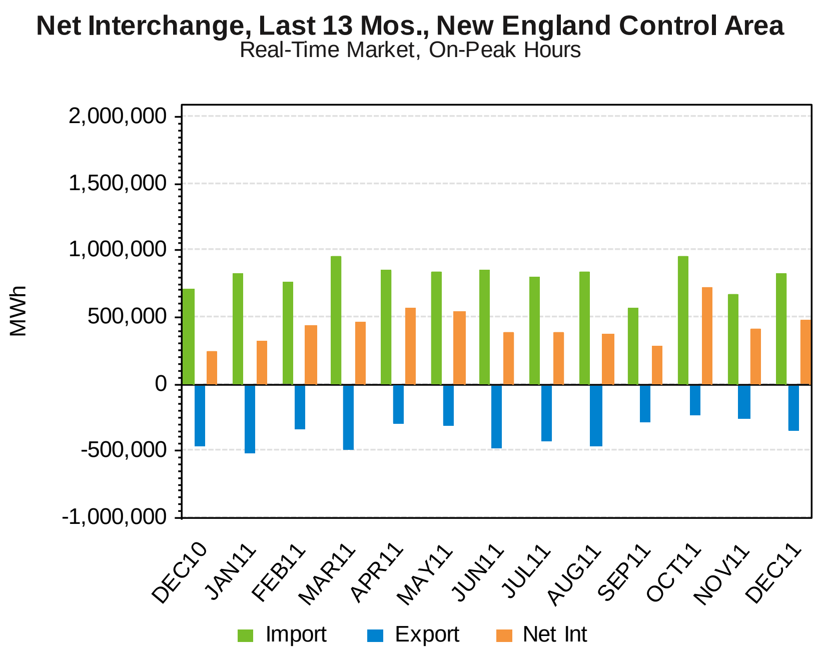
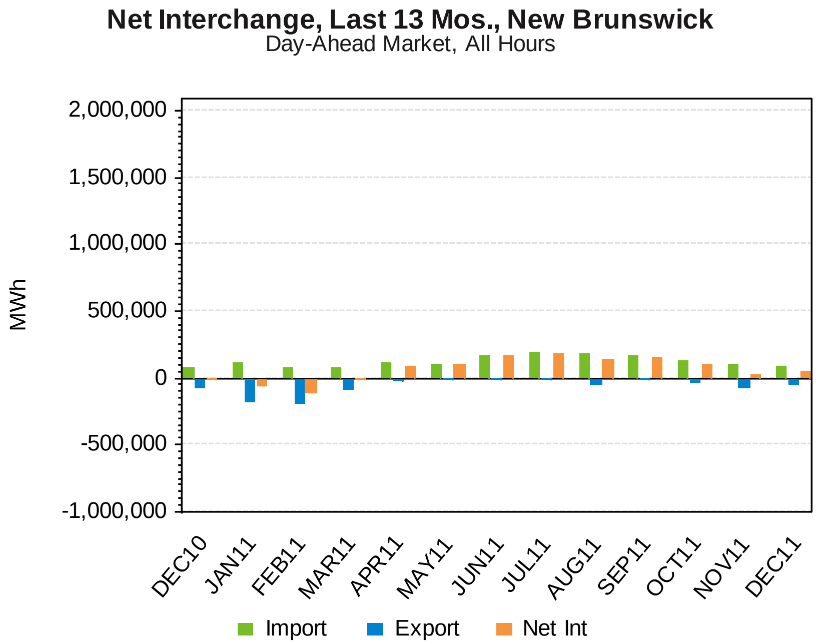
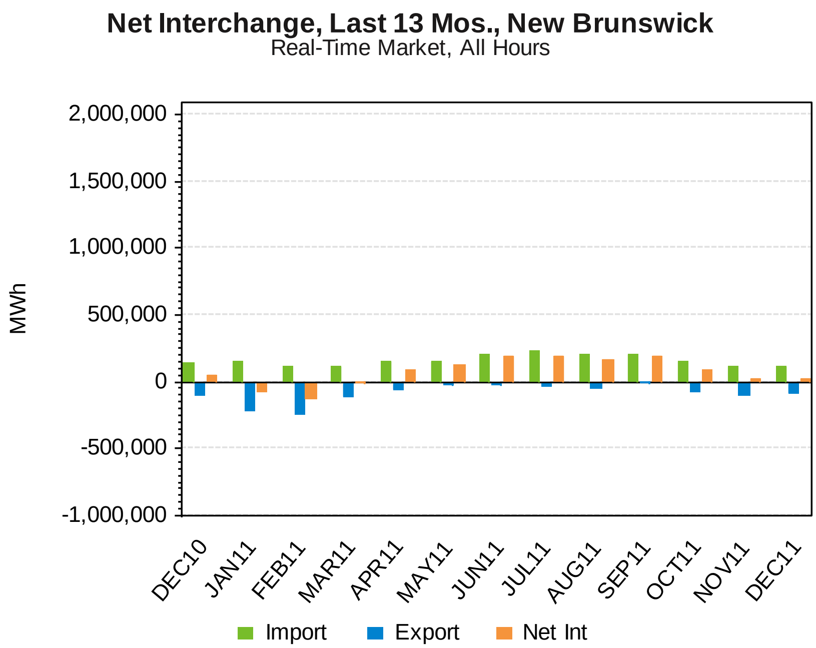
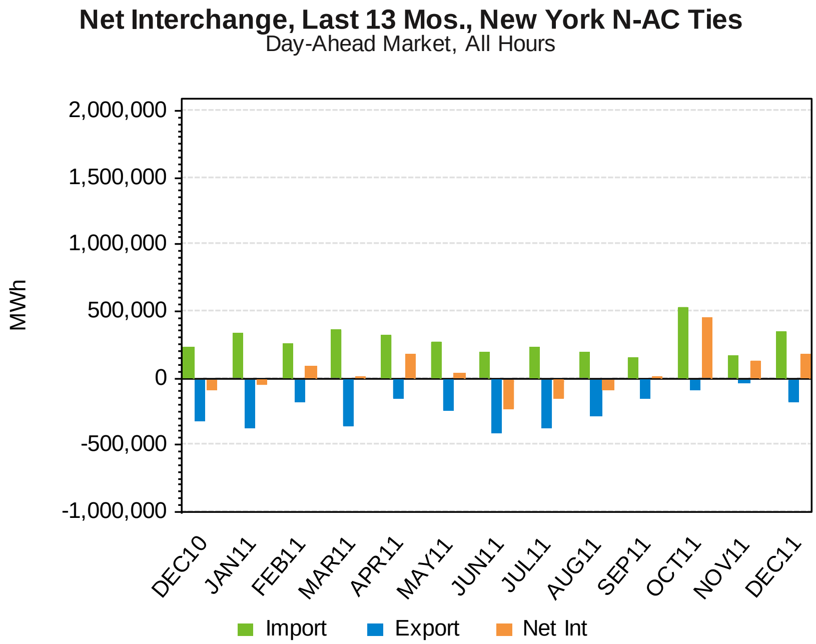
DEC11
Import
Export
Net Int

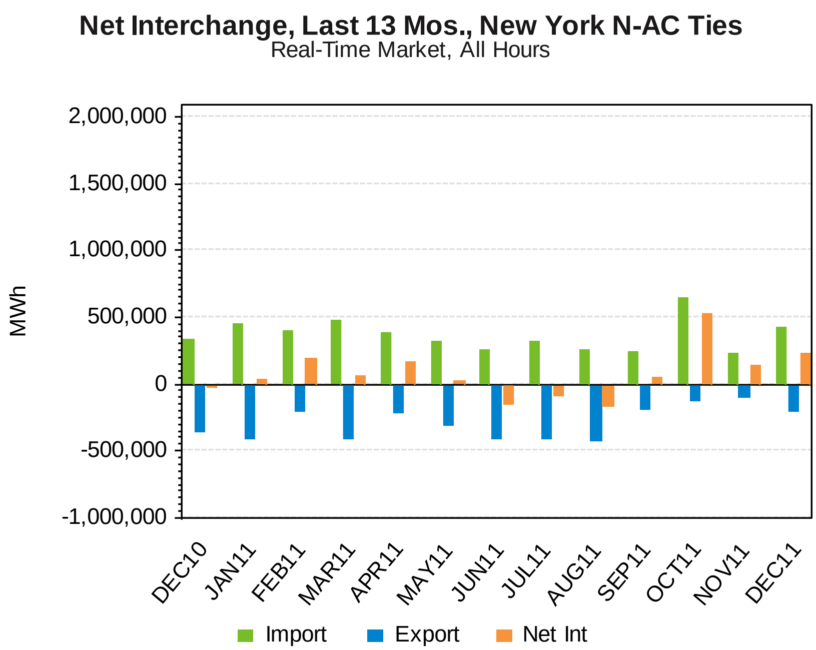

Net Interchange, Last 13 Mos., New England Control Area
Real-Time Market, On-Peak Hours
MWh
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
DEC10
JAN11
FEB11
MAR11
APR11
MAY11
JUN11
JUL11
AUG11
SEP11
OCT11
NOV11
DEC11
Import
Export
Net Int

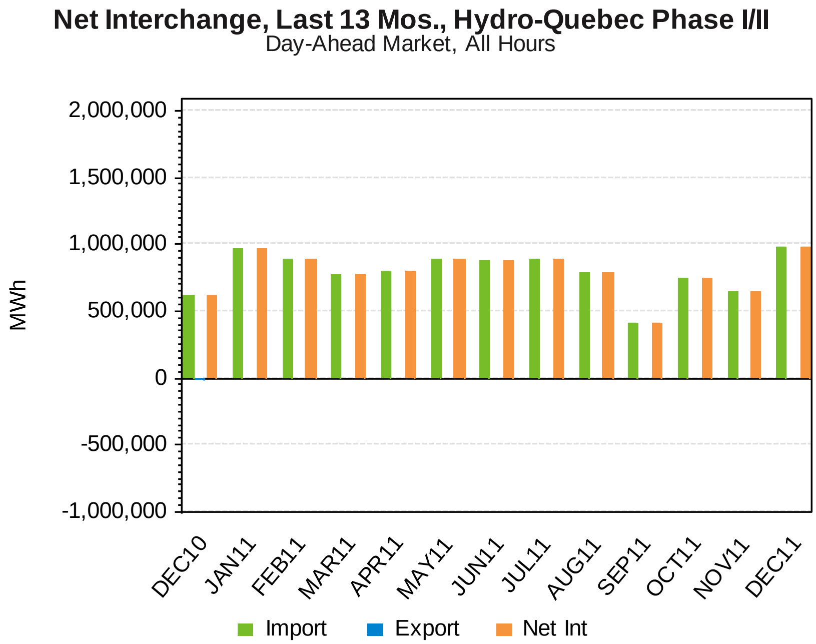
5.3 Net Interchange Summary by Interface, Last 13 Months

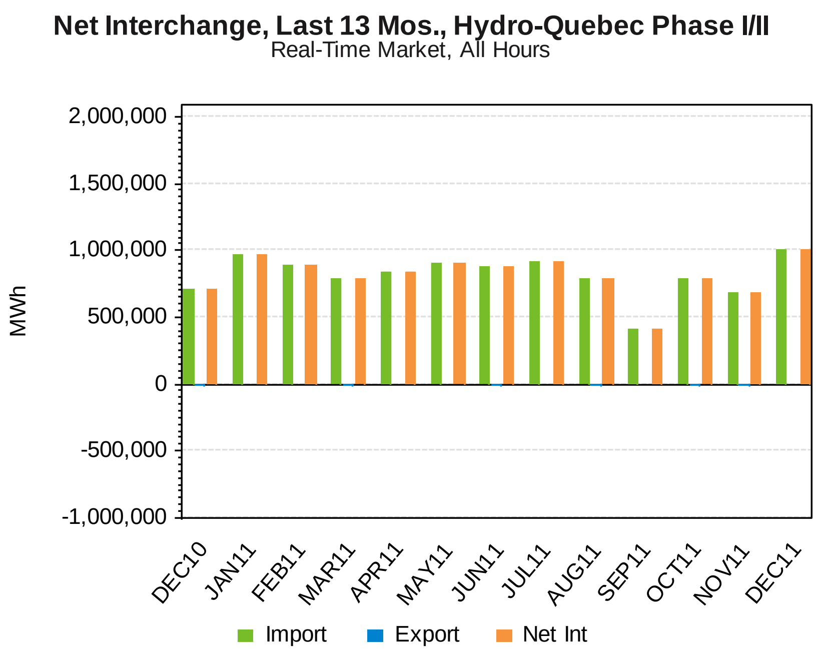


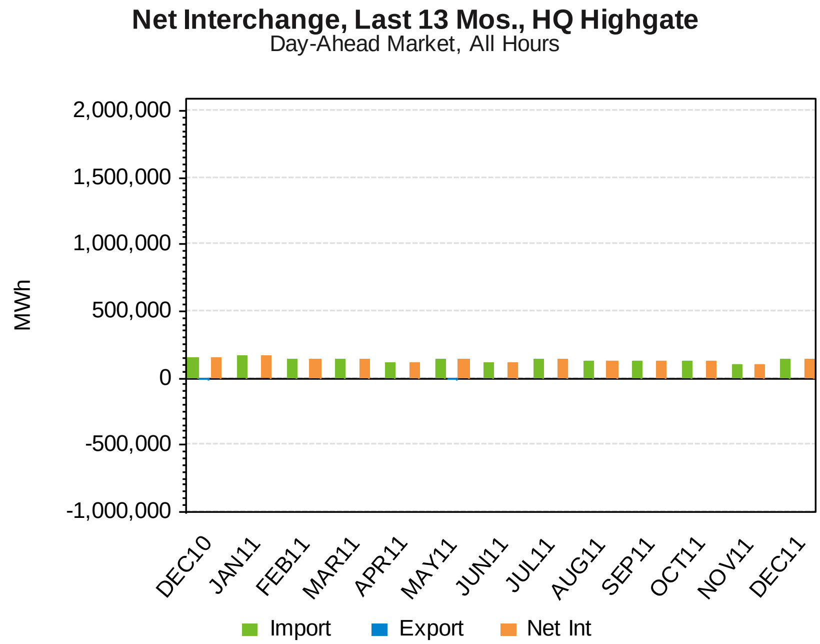


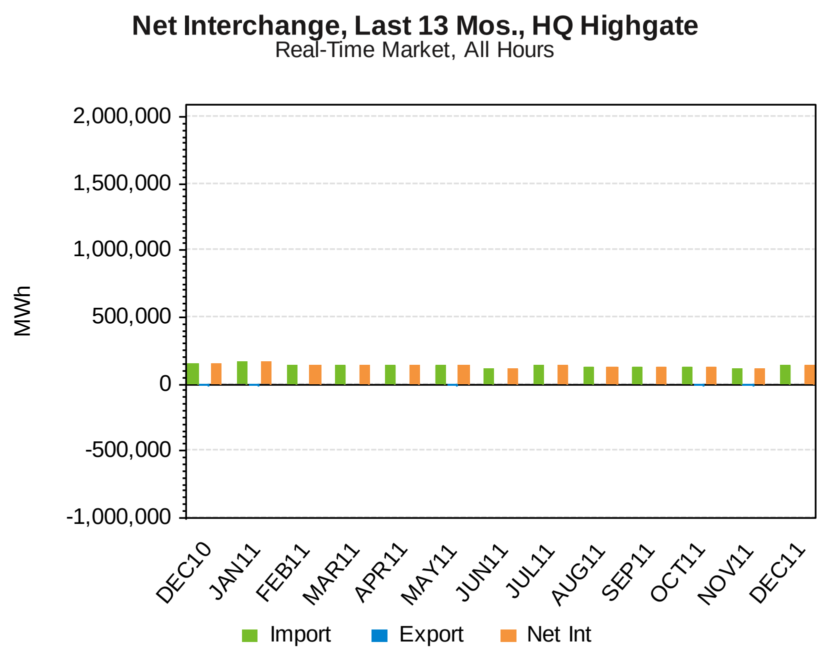

Net Interchange, Last 13 Mos., New York N-AC Ties
Day-Ahead Market, All Hours
MWh
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
DEC10
JAN11
FEB11
MAR11
APR11
MAY11
JUN11
JUL11
AUG11
SEP11
OCT11
NOV11
DEC11
Import
Export
Net Int

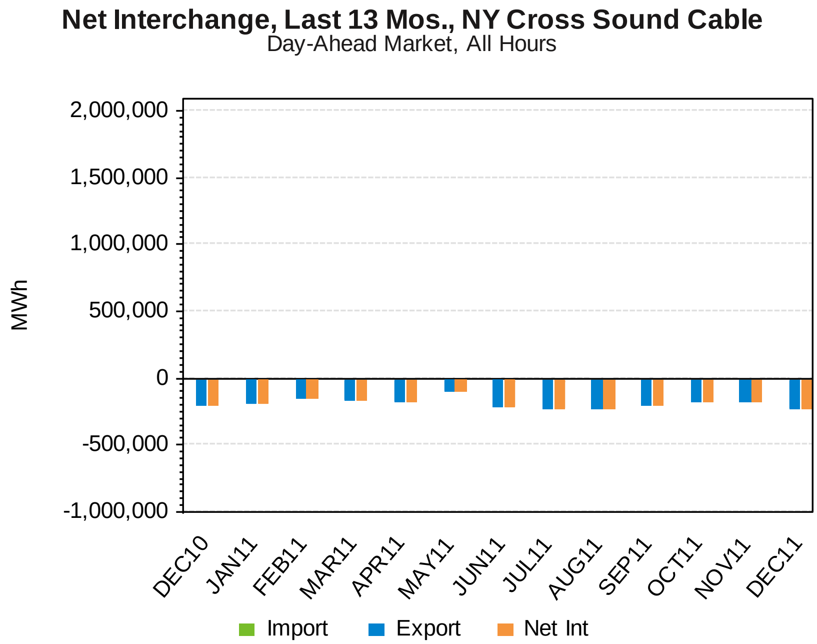

Net Interchange, Last 13 Mos., New York N-AC Ties
Real-Time Market, All Hours
MWh
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
DEC10
JAN11
FEB11
MAR11
APR11
MAY11
JUN11
JUL11
AUG11
SEP11
OCT11
NOV11
DEC11
Import
Export
Net Int

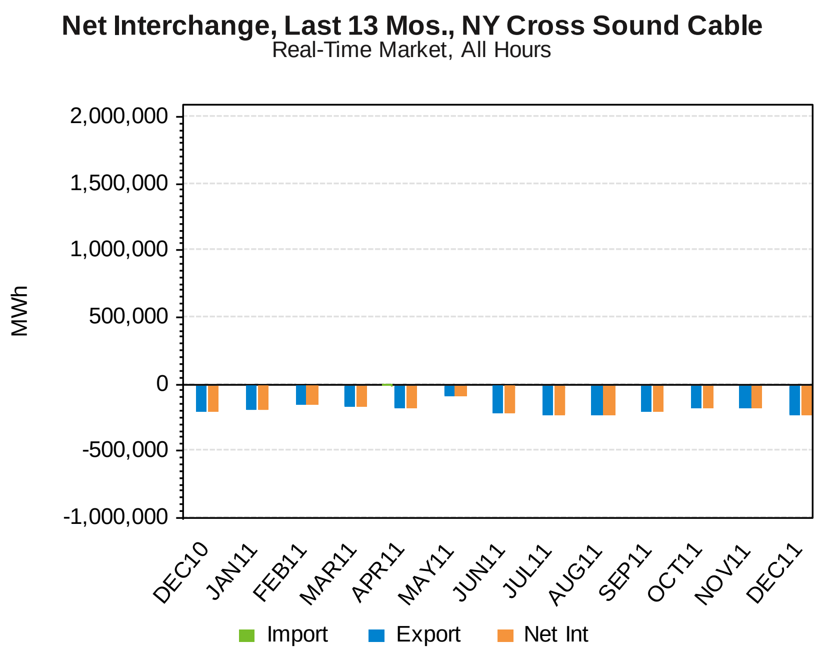

Net Interchange, Last 13 Mos., Hydro-Quebec Phase I/II
Day-Ahead Market, All Hours
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MWh
DEC10
JAN11
FEB11
MAR11
APR11
MAY11
JUN11
JUL11
AUG11
SEP11
OCT11
NOV11
DEC11
Import
Export
Net Int

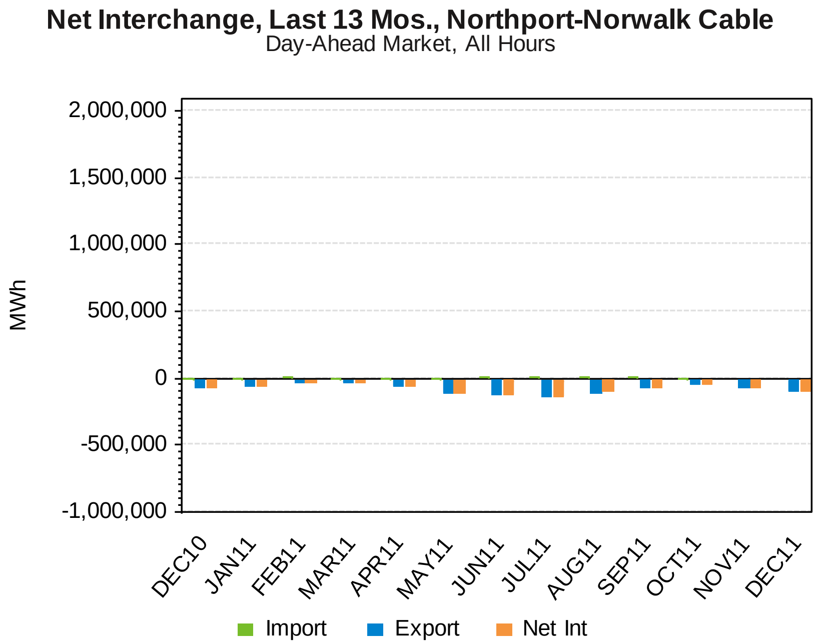

Net Interchange, Last 13 Mos., Hydro-Quebec Phase I/II
Real-Time Market, All Hours
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MWh
DEC10
JAN11
FEB11
MAR11
APR11
MAY11
JUN11
JUL11
AUG11
SEP11
OCT11
NOV11
DEC11
Import
Export
Net Int


Net Interchange, Last 13 Mos., HQ Highgate
Day-Ahead Market, All Hours
MWh
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
DEC10
JAN11
FEB11
MAR11
APR11
MAY11
JUN11
JUL11
AUG11
SEP11
OCT11
NOV11
DEC11
Import
Export
Net Int

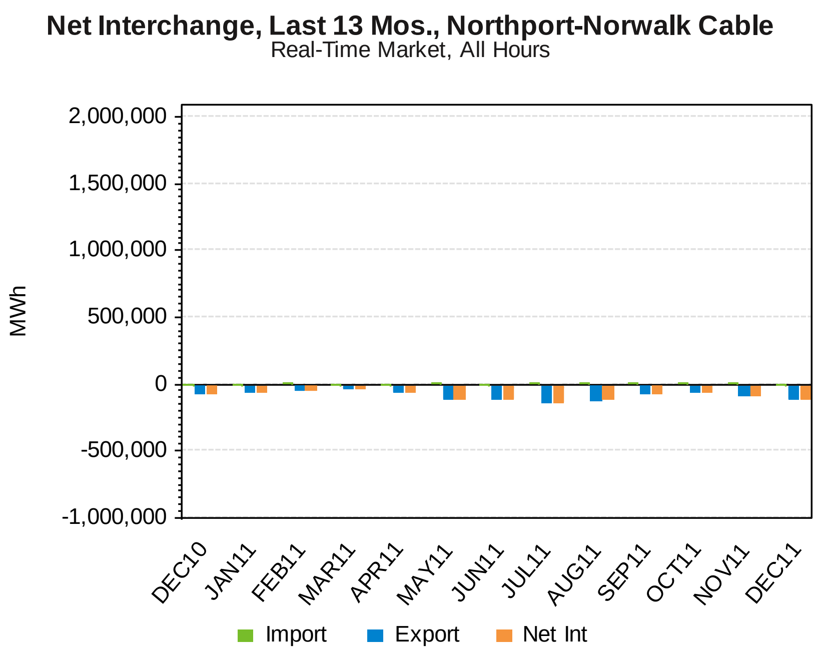

Net Interchange, Last 13 Mos., HQ Highgate
Real-Time Market, All Hours
MWh
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
DEC10
JAN11
FEB11
MAR11
APR11
MAY11
JUN11
JUL11
AUG11
SEP11
OCT11
NOV11
DEC11
Import
Export
Net Int


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
DEC10
JAN11
FEB11
MAR11
APR11
MAY11
JUN11
JUL11
AUG11
SEP11
OCT11
NOV11
DEC11
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
DEC10
JAN11
FEB11
MAR11
APR11
MAY11
JUN11
JUL11
AUG11
SEP11
OCT11
NOV11
DEC11
Import
Export
Net Int



Net Interchange, Last 13 Mos., Northport-Norwalk Cable
Day-Ahead Market, All Hours
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MWh
DEC10
JAN11
FEB11
MAR11
APR11
MAY11
JUN11
JUL11
AUG11
SEP11
OCT11
NOV11
DEC11
Import
Export
Net Int



Net Interchange, Last 13 Mos., Northport-Norwalk Cable
Real-Time Market, All Hours
2,000,000
1,500,000
1,000,000
500,000
0
-500,000
-1,000,000
MWh
DEC10
JAN11
FEB11
MAR11
APR11
MAY11
JUN11
JUL11
AUG11
SEP11
OCT11
NOV11
DEC11
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 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, December 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	7,521	45,969	-$1,190,817	3,095	15,661	$127,369
Buy	On	8,346	56,945	-$1,499,522	2,846	16,780	$449,634
Buy	Buy Total	15,867	102,914	-$2,690,339	5,941	32,441	$577,003
Sell	Off	1,179	4,129	$315,084	60	246	$2,649
Sell	On	1,111	3,500	$511,903	115	354	-$2,889
Sell	Sell Total	2,290	7,628	$826,987	175	600	-$240
Grand Total	Grand Total	18,157	110,543	-$1,863,352	6,116	33,041	$576,763

6.1.2 Number of Auction Participants, December 2011

Auction Period	Monthly or Long-Term	No. of Bidders
Dec 2011	MO	34

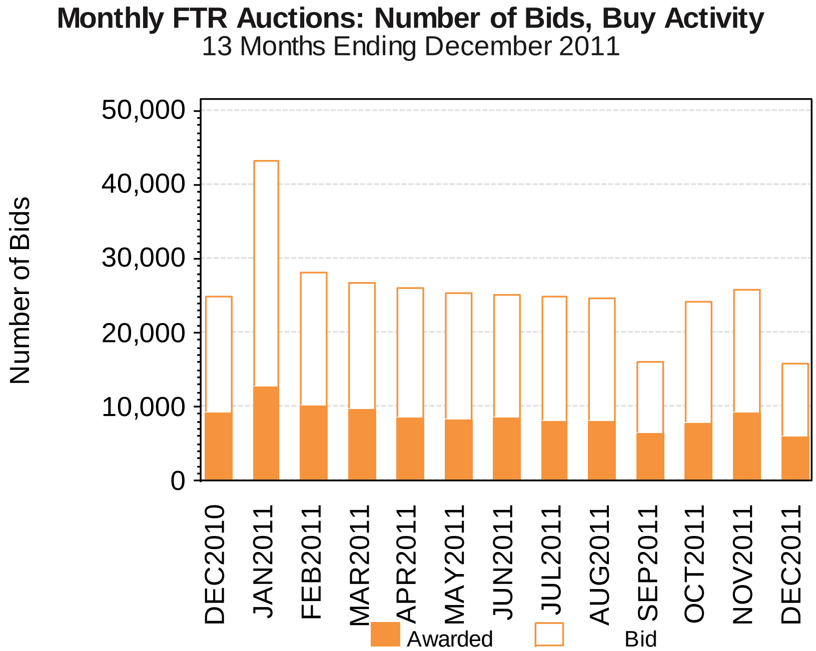
6.1.3 Monthly FTR Auction Results, Last 13 Months

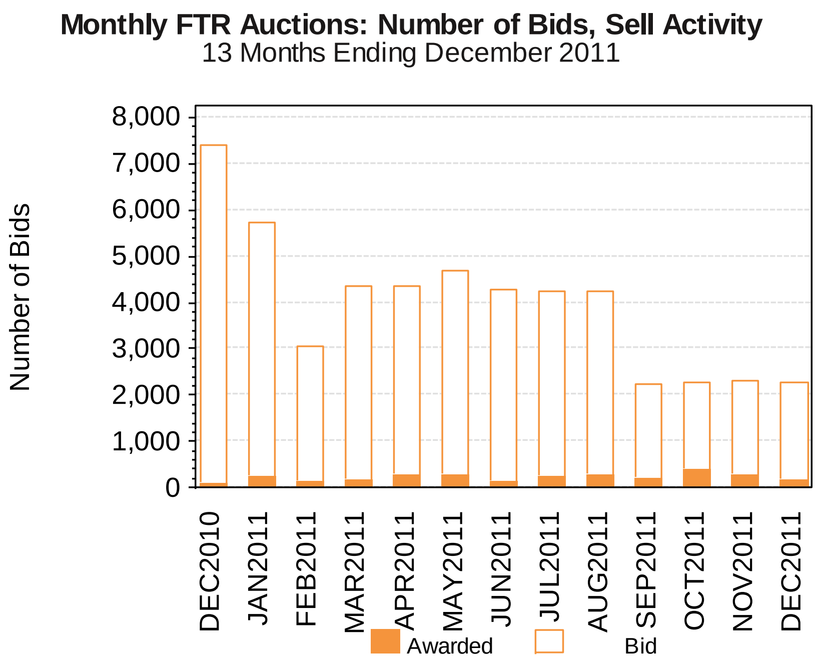
Auction Month	Bids to Buy or Offers to Sell	No. of Bids or Offers	Bid or Offered MW-Mos.	Bid or Offered Dollars	No. of Awards	Awarded MW-Mos.	Awarded Dollars
DEC 2010	Buy	24,851	187,475	-$2,767,650	9,144	51,188	$819,043
DEC 2010	Sell	7,417	21,235	$2,811,101	80	223	-$28,735
DEC 2010	Tot	32,268	208,710	$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

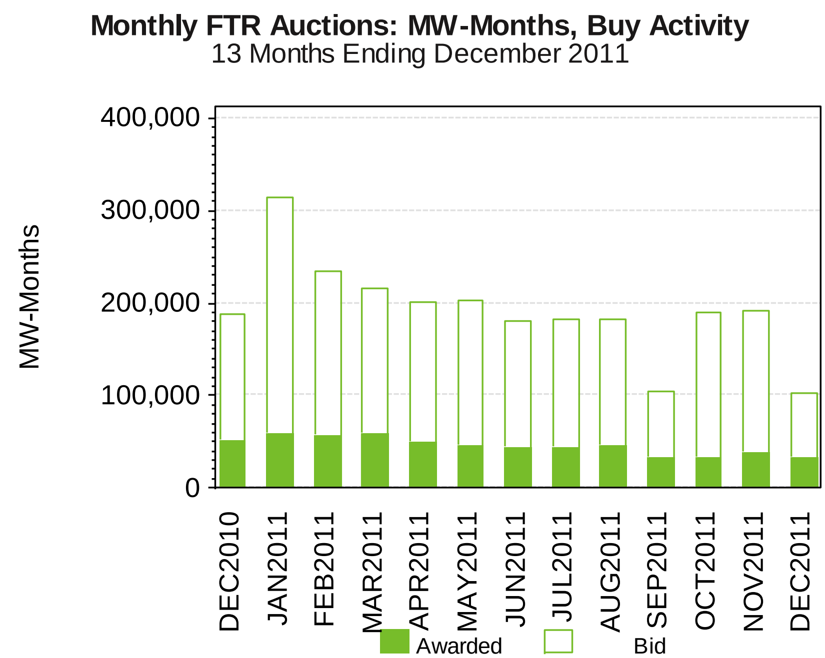
Auction Month	Bids to Buy or Offers to Sell	No. of Bids or Offers	Bid or Offered MW-Mos.	Bid or Offered Dollars	No. of Awards	Awarded MW-Mos.	Awarded Dollars
FEB 2011	Sell	3,037	11,808	$1,309,695	102	166	-$5,531
FEB 2011	Tot	31,165	246,377	-$2,839,380	10,064	57,159	$587,463
MAR 2011	Buy	26,843	215,392	-$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
SEP 2011	Buy	16,082	104,630	-$5,702,205	6,396	32,342	$354,459
SEP 2011	Sell	2,255	7,420	$750,334	200	602	-$8,927
SEP 2011	Tot	18,337	112,050	-$4,951,870	6,596	32,944	$345,532
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
DEC 2011	Tot	18,157	110,543	-$1,863,352	6,116	33,041	$576,763

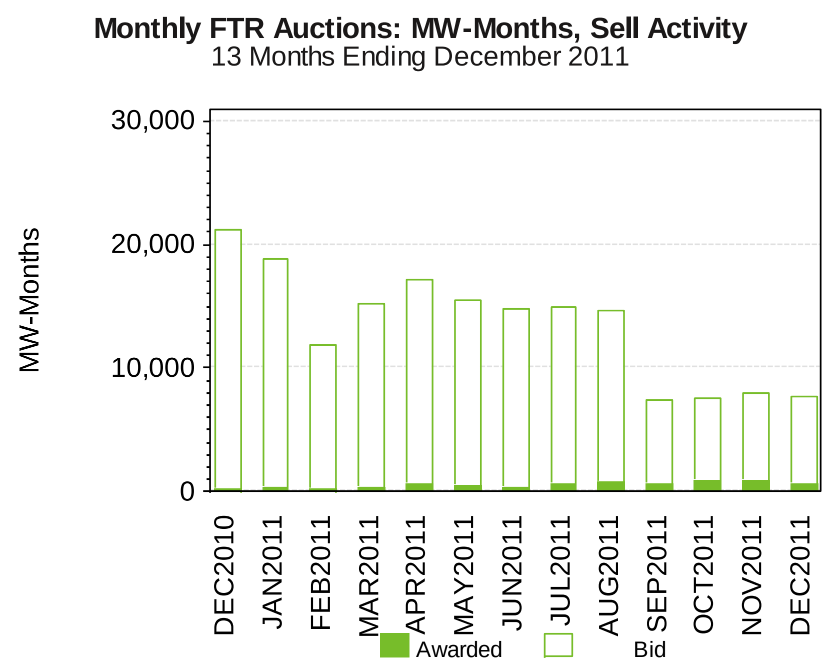
6.2 Monthly FTR Auction Results, Last 13 Months

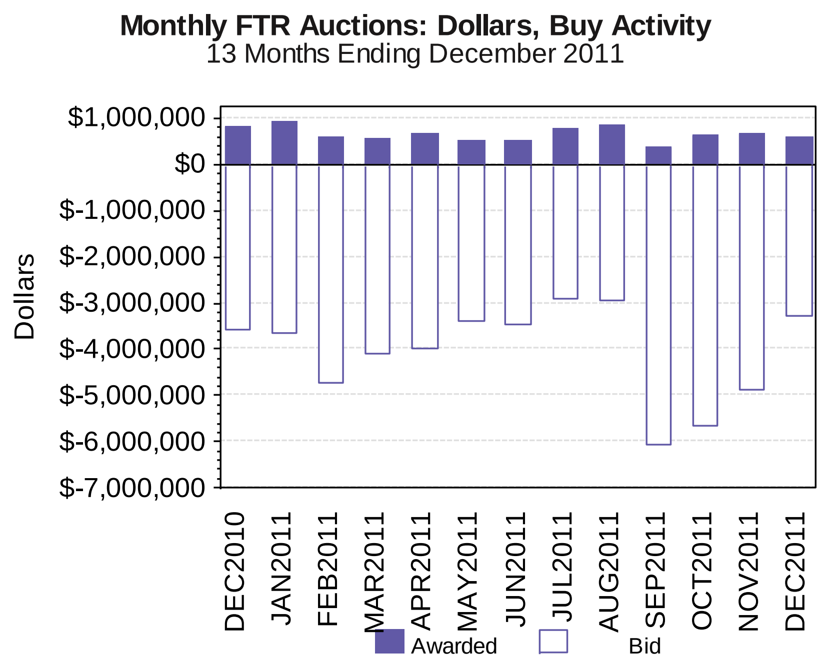
The next series of graphs show summaries of FTR Auction activity over the last 13 months, including bids to buy monthly FTRs and offers to sell long-term FTRs into each monthly auction.

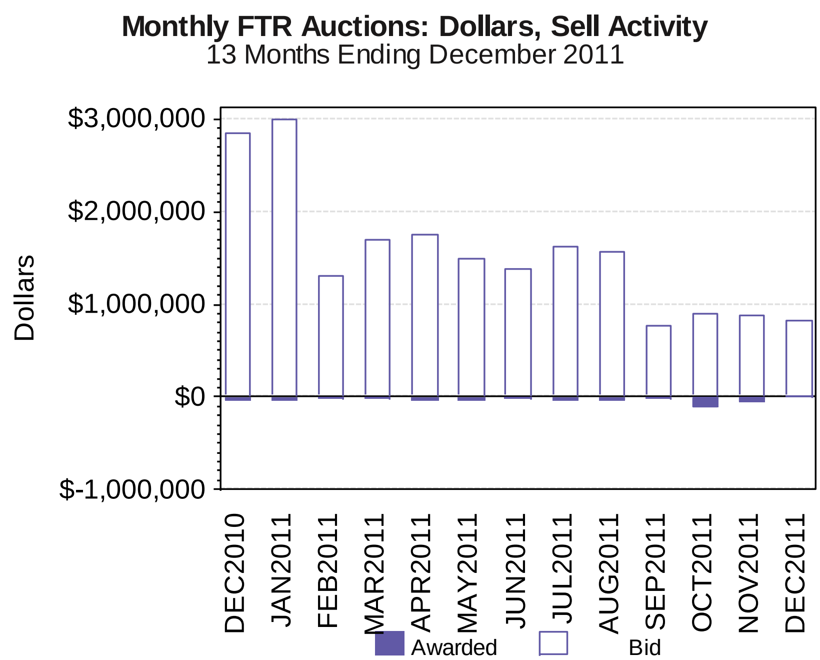

Monthly FTR Auctions: Number of Bids, Buy Activity
13 Months Ending December 2011
Number of Bids
50,000
40,000
30,000
20,000
10,000
0
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
Awarded
Bid


Monthly FTR Auctions: Number of Bids, Sell Activity
13 Months Ending December 2011
Number of Bids
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
Awarded
Bid


Monthly FTR Auctions: MW-Months, Buy Activity
13 Months Ending December 2011
MW-Months
400,000
300,000
200,000
100,000
0
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
Awarded
Bid

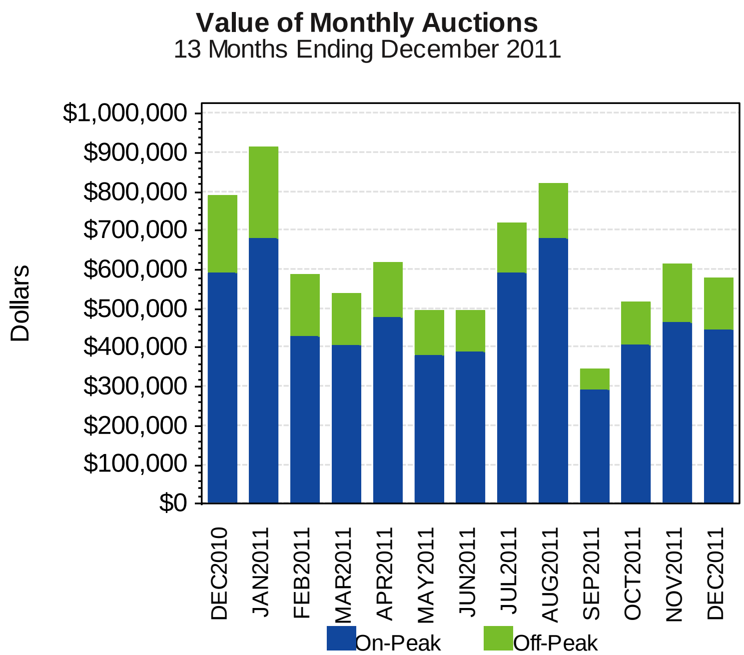

Monthly FTR Auctions: MW-Months, Sell Activity
13 Months Ending December 2011
MW-Months
30,000
20,000
10,000
0
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
Awarded
Bid

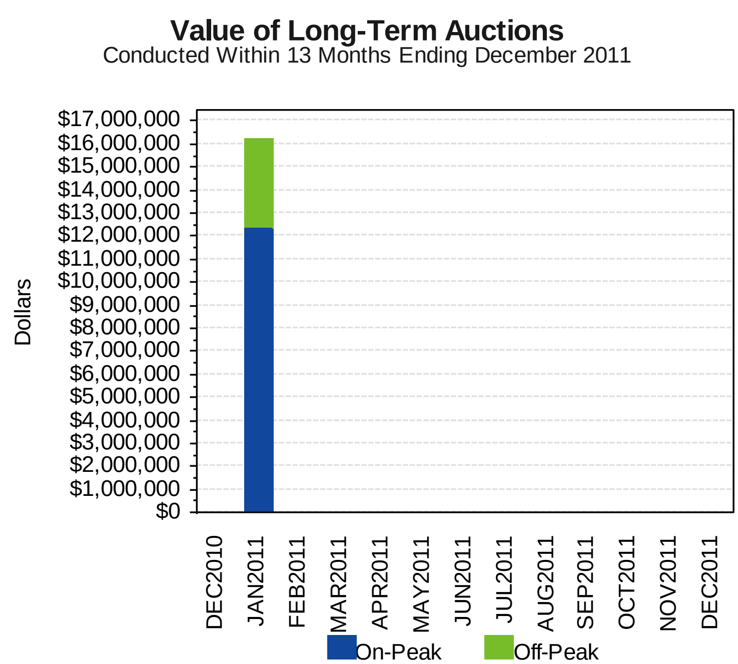

Monthly FTR Auctions: Dollars, Buy Activity
13 Months Ending December 2011
Dollars
$1,000,000
$0
$-1,000,000
$-2,000,000
$-3,000,000
$-4,000,000
$-5,000,000
$-6,000,000
$-7,000,000
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
Awarded
Bid

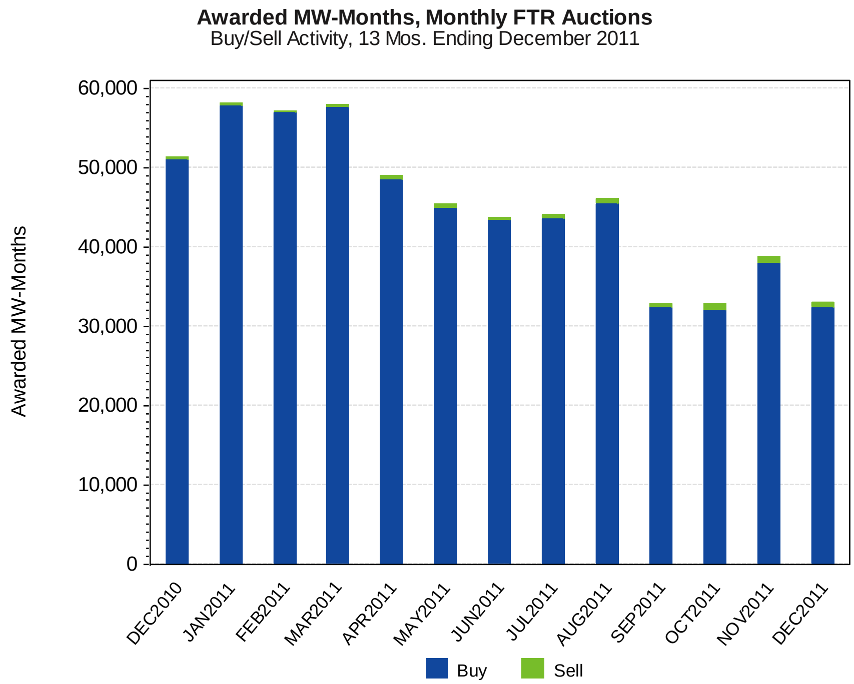

Monthly FTR Auctions: Dollars, Sell Activity
13 Months Ending December 2011
Dollars
$3,000,000
$2,000,000
$1,000,000
$0
$-1,000,000
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
Awarded
Bid

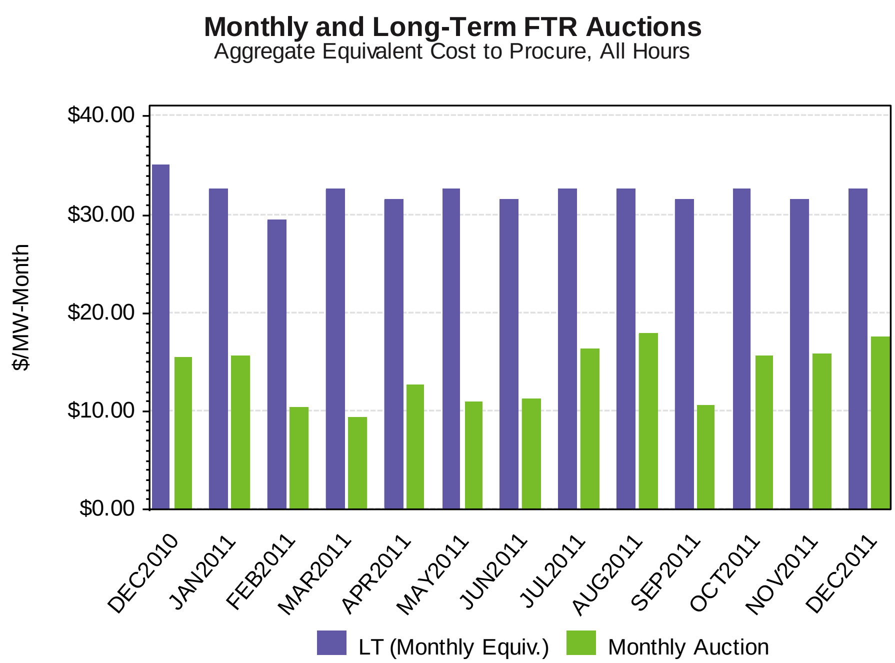
6.3 Auction Value, Last 13 Months

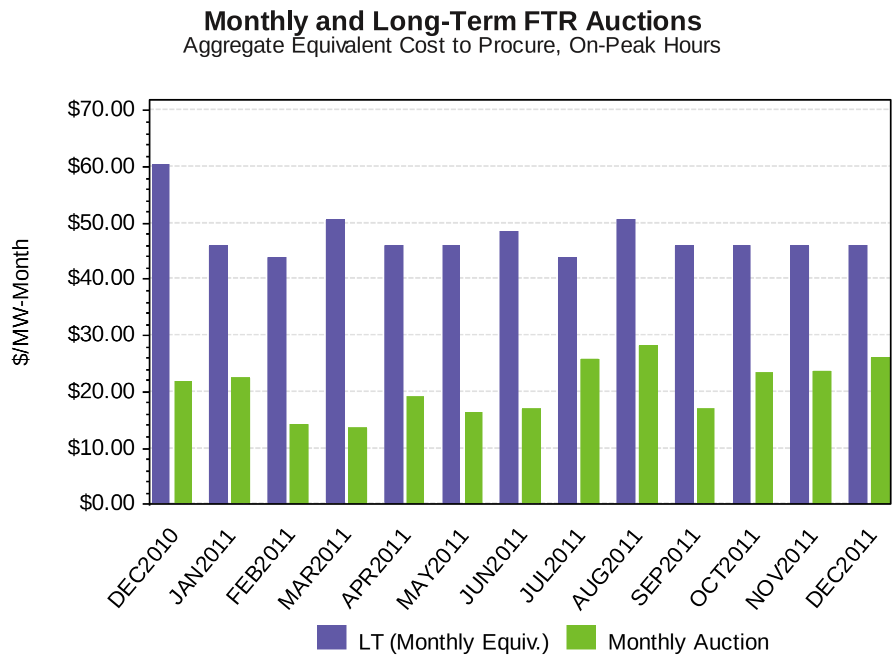
The next series of graphs show summaries of FTR Auction value and on/off-peak activity over the last 13 months.

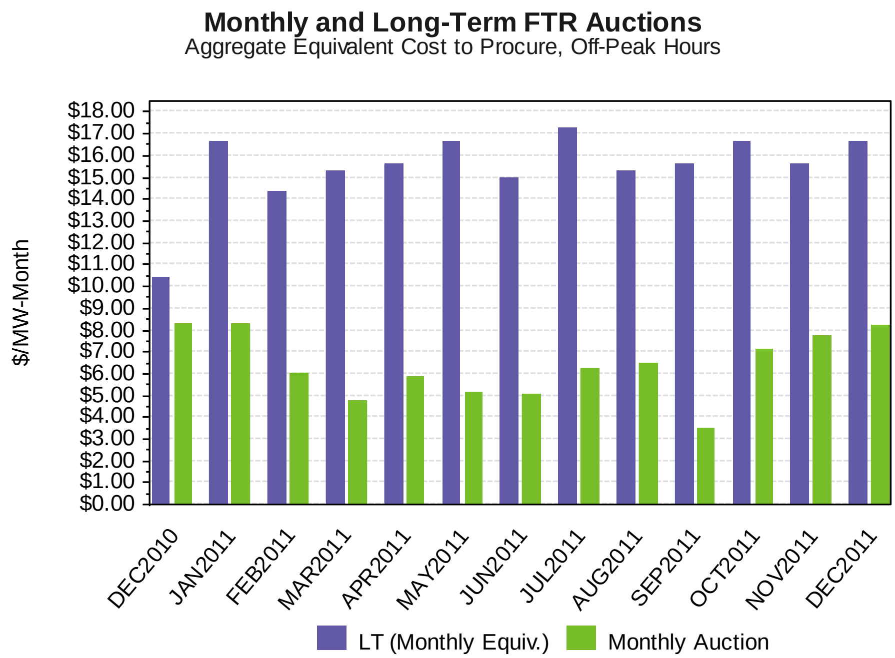





Awarded MW-Months, Monthly FTR Auctions
Buy/Sell Activity, 13 Mos. Ending December 2011
Awarded MW-Months
60,000
50,000
40,000
30,000
20,000
10,000
0
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
Buy
Sell


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
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
LT (Monthly Equiv.)
Monthly Auction


Monthly and Long-Term FTR Auctions
Aggregate Equivalent Cost to Procure, On-Peak Hours
$/MW-Month
$70.00
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$0.00
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
LT (Monthly Equiv.)
Monthly Auction


Monthly and Long-Term FTR Auctions
Aggregate Equivalent Cost to Procure, Off-Peak Hours
$/MW-Month
$18.00
$17.00
$16.00
$15.00
$14.00
$13.00
$12.00
$11.00
$10.00
$9.00
$8.00
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
DEC2010
JAN2011
FEB2011
MAR2011
APR2011
MAY2011
JUN2011
JUL2011
AUG2011
SEP2011
OCT2011
NOV2011
DEC2011
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 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

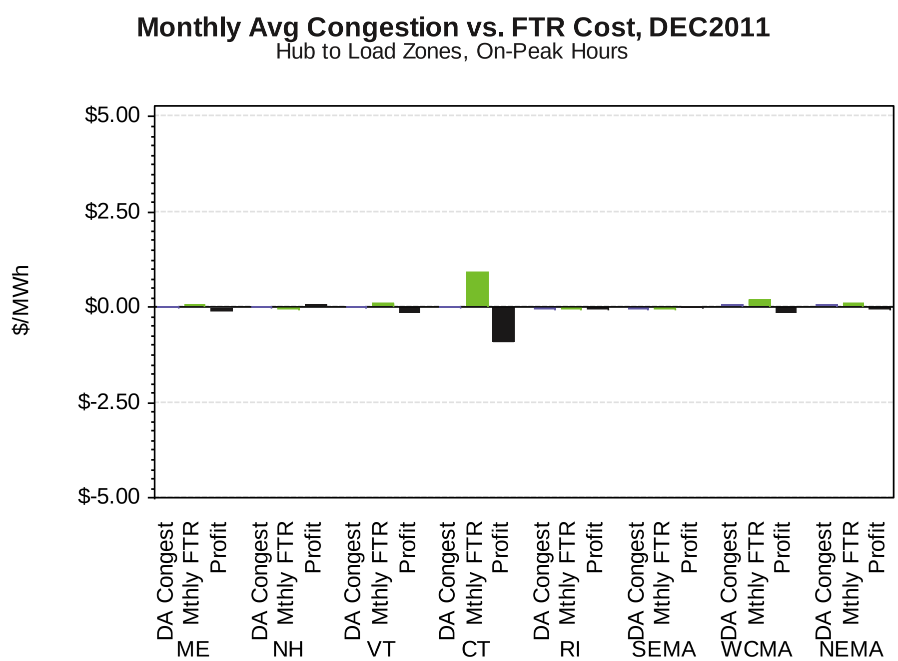
7. Effectiveness of FTRs

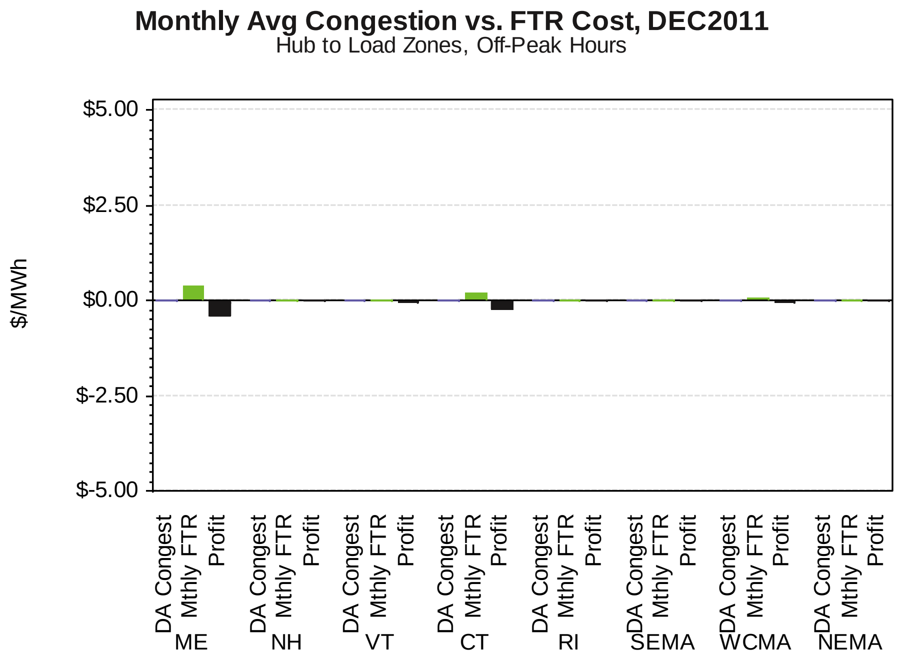
7.1 FTRs as a Congestion Hedging Instrument

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 December 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	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
ME	Sep-11	-$0.18	-$0.11	-$0.07
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

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
NH	Sep-11	$0.00	-$0.11	$0.11
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

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
VT	Sep-11	-$0.01	-$0.08	$0.08
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

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
CT	Sep-11	$1.91	$0.90	$1.01
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

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
RI	Sep-11	-$0.01	-$0.13	$0.12
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

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
SEMA	Sep-11	-$0.02	-$0.09	$0.07
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

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
WCMA	Sep-11	$0.16	$0.12	$0.04
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

Hub to	Month	Avg DA Congest	FTR Path Cost	FTR Profit
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
NEMA	Sep-11	$0.16	$0.01	$0.15
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

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
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
Sep-11	-$1,680,738	$19	$6,881	$1,509,211	$1,516,112	$164,627	$1,680,738
Oct-11	-$1,895,027	$12	$4,945	$1,683,587	$1,688,544	$206,483	$1,895,027
Nov-11	-$1,947,413	$14	$5,842	$1,674,948	$1,680,804	$266,609	$1,947,413
Dec-11	-$1,956,476	$19	$6,534	$1,821,885	$1,828,438	$128,038	$1,956,476

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
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
Sep-11	$11,513	$26,880	$42,000	$735,830	$14,814	$35,290	$152,755	$147,510
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

Off Peak								
Month	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
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
Sep-11	$40,123	$3,484	$8,904	$178,751	$7,492	$16,970	$65,283	$28,513
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

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 December 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 eleventh Forward Reserve Market Auction, covering the Winter 2011/12 Procurement Period (October-May) cleared on August 30, 2011. 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 December 2011, the threshold price was set at $84.97.

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, December 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	$834,173	$814,127	-$30,128	$0	$783,999	94%
SYSTEM	TMOR	$345,943	$339,800	-$9,226	$0	$330,574	96%
SYSTEM	TOTAL	$1,180,116	$1,153,927	-$39,354	$0	$1,114,573	94%
ROS	TMNSR	$539,556	$525,446	-$21,209	$0	$504,237	93%
ROS	TMOR	$13,487	$12,011	-$2,216	$0	$9,795	73%
ROS	TOTAL	$553,043	$537,457	-$23,426	$0	$514,032	93%
SWCT	TMNSR	$0	$0	$0	$0	$0	n/a
SWCT	TMOR	$147,384	$146,375	-$1,515	$0	$144,860	98%
SWCT	TOTAL	$147,384	$146,375	-$1,515	$0	$144,860	98%
CT	TMNSR	$294,617	$288,681	-$8,919	$0	$279,762	95%
CT	TMOR	$185,072	$181,414	-$5,495	$0	$175,919	95%
CT	TOTAL	$479,689	$470,095	-$14,414	$0	$455,681	95%
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.

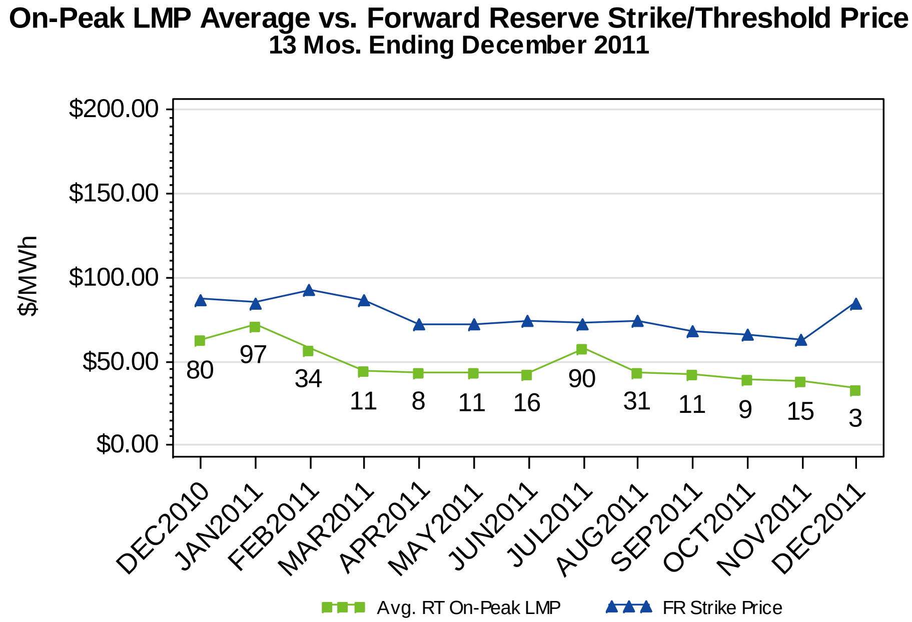
The ISO allocates Forward Reserve Credits, net of Forward Reserve Failure-to-Reserve Penalties and Forward Reserve Failure-to-Activate Penalties, to each Load Zone. The Forward Reserve charge allocation method changed on June 1, 2011. Under the new Forward Reserve Cost Allocation, the Forward Reserves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

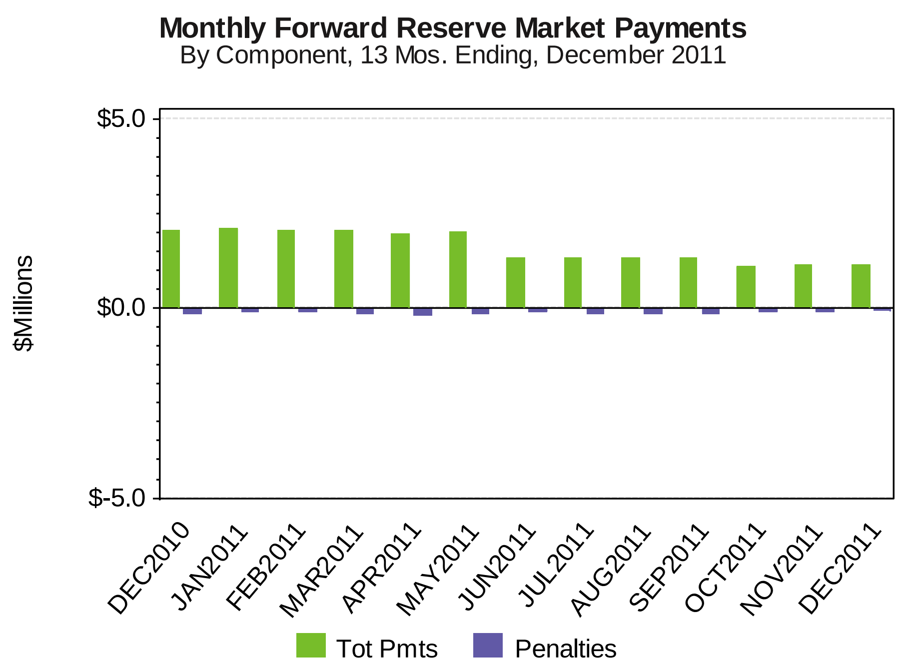
Load Zone	FRM Charge
ME	$99,864
NH	$105,112
VT	$54,147
CT	$271,955
RI	$71,630
SEMA	$131,595
WCMA	$156,796
NEMA	$223,474
ALL	$1,114,573

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 72 separate hours. On a reserve zone basis, non-zero prices occurred thus: CT-72 hours; NEMABSTN-72 hours; ROS-72 hours; SWCT-72 hours. The total compensation paid to assets providing real-time reserves during December 2011, and reductions in those payments for the Forward Reserve Obligation Charge are shown in the following table:

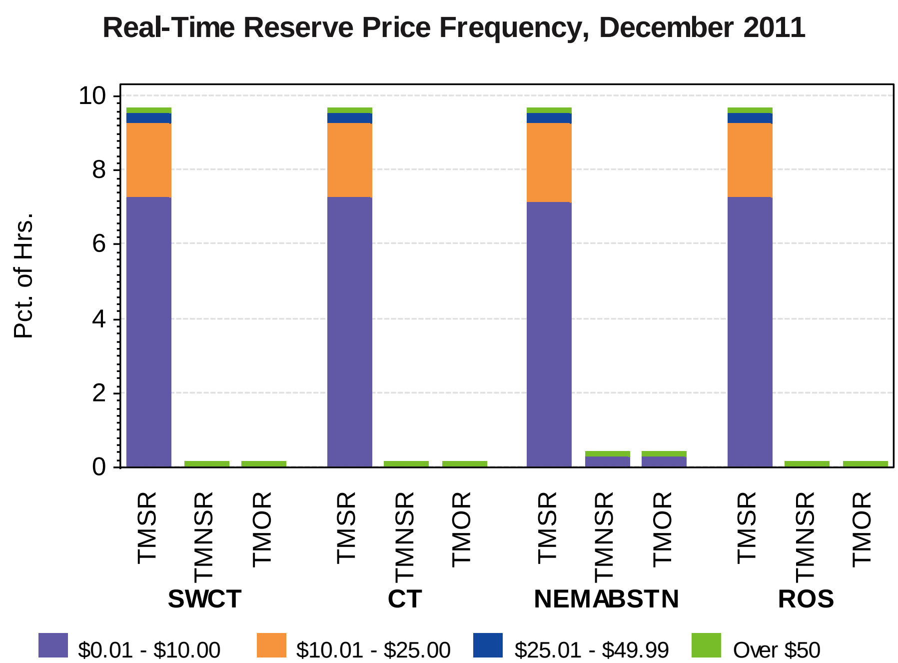
Reserve Zone	Real-Time Reserve Credits	Fwd Reserve Obligation Charges	Net Real-Time Reserve Payments
SYSTEM	$584,493	($105,374)	$479,119
ROS	$456,341	($88,313)	$368,028
SWCT	$54,172	($6,776)	$47,396
CT	$48,134	($10,285)	$37,849
NEMABSTN	$25,846	$0	$25,846

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	$36,452
ME	TMNSR	$3,687
ME	TMOR	$2,432
ME	ALL	$42,571
NH	TMSR	$38,633
NH	TMNSR	$3,988
NH	TMOR	$2,631
NH	ALL	$45,252
VT	TMSR	$19,559
VT	TMNSR	$2,083
VT	TMOR	$1,374
VT	ALL	$23,015
CT	TMSR	$100,081
CT	TMNSR	$10,526
CT	TMOR	$6,945
CT	ALL	$117,551
RI	TMSR	$26,154
RI	TMNSR	$2,617

Load Zone	Reserve Product	RT Reserve Charge
RI	TMOR	$1,726
RI	ALL	$30,497
SEMA	TMSR	$48,828
SEMA	TMNSR	$4,930
SEMA	TMOR	$3,253
SEMA	ALL	$57,011
WCMA	TMSR	$57,281
WCMA	TMNSR	$5,958
WCMA	TMOR	$3,931
WCMA	ALL	$67,170
NEMA	TMSR	$81,541
NEMA	TMNSR	$8,693
NEMA	TMOR	$5,817
NEMA	ALL	$96,051

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

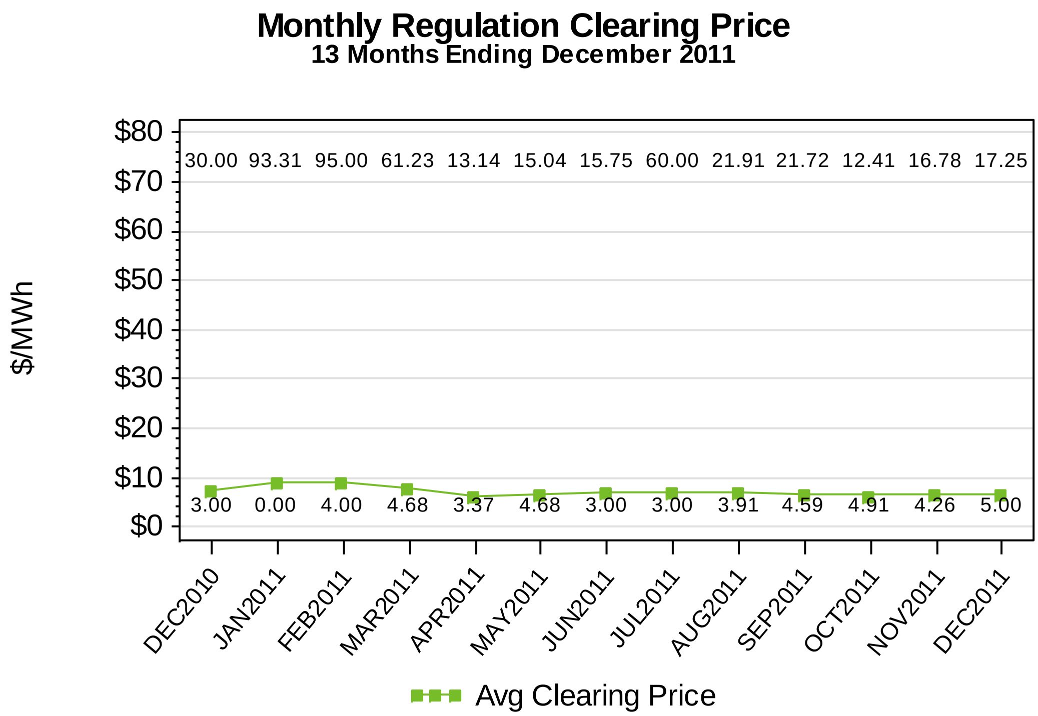
The business rules and procedures for forward and real-time reserve can be found in the ISO's Manual 28 –Market Rule 1 Accounting located at:
http://www.iso-ne.com/rules_proceds/isone_mnls/index.html

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

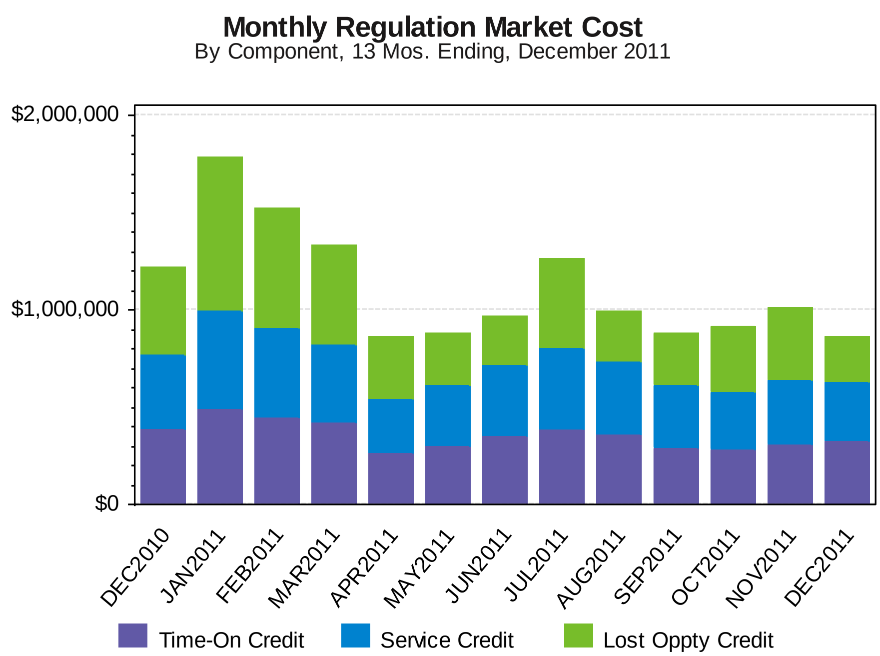
10.2 Monthly Regulation Market Clearing Price Statistics, Last 13 Months

	On-Peak Clearing Price Statistics			
Month	Mean	Max	Min	StdDev
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
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	On-Peak Clearing Price Statistics			
	Mean	Max	Min	StdDev
Sep-11	$6.66	$21.72	$4.68	$1.69
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

Month	Off-Peak Clearing Price Statistics			
	Mean	Max	Min	StdDev
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
Sep-11	$6.66	$13.04	$4.59	$1.06
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

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
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
Sep-11	$287,312	$270,471	$322,823	$880,605
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

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 December 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
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	$1,914,341	-$21,447,730	-$1,330,884	$153,084	$0	$9,202,872	-$736,540	$8,466,332
Feb-11	$8,274,472	$1,585,313	-$14,674,081	-$751,610	$511,937	$0	$6,399,609	-$1,345,640	$5,053,969
Mar-11	$7,513,684	$1,059,891	-$13,023,982	-$579,559	$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	$617,705	-$13,592,447	-$757,260	$472,590	$0	$5,559,476	-$333,034	$5,226,442
Jul-11	$11,775,447	$855,061	-$22,409,017	-$1,777,328	$325,837	$0	$10,633,570	$596,431	$11,230,001
Aug-11	$8,371,799	$932,612	-$15,806,648	-$602,217	$533,437	$0	$7,434,849	-$863,832	$6,571,017
Sep-11	$6,711,481	$1,826,971	-$12,236,326	-$790,045	-$125,537	$0	$5,524,845	-$911,390	$4,613,455
Oct-11	$5,307,838	$1,111,800	-$10,008,931	-$468,227	-$3,567	$0	$4,701,093	-$640,007	$4,061,086
Nov-11	$5,133,343	$878,991	-$9,538,871	-$581,405	$6,598	$0	$4,405,528	-$304,184	$4,101,344
Dec-11	$5,450,618	$1,781,367	-$10,191,890	-$417,593	-$826,680	$0	$4,741,272	-$537,095	$4,204,177

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 that Supply Credit is the sum of CSO Payments of all types Forward Capacity Auction (FCA) Credits, Bilateral Dollars and Reconfiguration Auction (RA) Dollars.

Month	FCA Credit	Bilateral Dollars	Reconfiguration Auction Dollars	Supply Credit
Dec-10	$138,065,067	$0	-$346,692	$137,718,375
Jan-11	$137,956,880	$0	-$346,692	$137,610,188
Feb-11	$137,955,785	$0	-$346,692	$137,609,093
Mar-11	$137,954,828	$0	-$346,692	$137,608,136
Apr-11	$137,971,982	$0	-$346,692	$137,625,290
May-11	$137,971,982	$0	-$346,692	$137,625,290
Jun-11	$111,025,627	$0	-$27,405	$110,998,222
Jul-11	$111,025,627	$0	-$27,405	$110,998,222
Aug-11	$111,025,627	$0	-$27,405	$110,998,222
Sep-11	$111,025,627	$0	-$27,405	$110,998,222
Oct-11	$111,654,434	$0	-$27,405	$111,627,029
Nov-11	$111,646,529	$0	-$27,704	$111,618,825
Dec-11	$111,646,518	$0	-$27,704	$111,618,814

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 above 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 adjusted for PER and excess penalties to DR results 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)	PER Adjustment	Supply Credit Adjusted for PER	Excess DR Penalties	NRCP Credit	Reliability Credit	Total Payment
Dec-10	Rest-of-Pool	32,909	-$18,020,748	$119,697,627	$0	$119,697,627	$282,690	$119,980,317
Jan-11	Rest-of-Pool	32,883	-$17,623,453	$119,986,735	$0	$119,986,735	$282,690	$120,269,425
Feb-11	Rest-of-Pool	32,883	-$17,181,012	$120,428,082	$0	$120,428,082	$282,690	$120,710,772
Mar-11	Rest-of-Pool	32,814	-$16,790,839	$120,817,297	$0	$120,817,297	$282,690	$121,099,987
Apr-11	Rest-of-Pool	32,818	-$16,336,232	$121,289,058	$0	$121,289,058	$282,690	$121,571,748
May-11	Rest-of-Pool	32,818	-$16,325,239	$121,300,051	$0	$121,300,051	$282,690	$121,582,741
Jun-11	Rest-of-Pool	33,322	-$14,042,658	$96,955,564	$0	$96,955,564	$0	$96,955,564
Jul-11	Rest-of-Pool	33,322	-$12,131,439	$98,866,783	$0	$98,866,783	$0	$98,866,783
Aug-11	Rest-of-Pool	33,322	-$7,936,773	$103,061,449	$0	$103,061,449	$0	$103,061,449
Sep-11	Rest-of-Pool	33,322	-$2,866,970	$108,131,252	$0	$108,131,252	$0	$108,131,252
Oct-11	Rest-of-Pool	33,509	-$267,586	$111,359,443	$0	$111,359,443	$0	$111,359,443
Nov-11	Rest-of-Pool	33,507	-$208,255	$111,410,570	$0	$111,410,570	$0	$111,410,570
Dec-11	Rest-of-Pool	33,507	$0	$111,618,814	$0	$111,618,814	$0	$111,618,814

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
Dec-10	Rest-of-Pool	32,909	1,440	0	182	1,661	32,727	24,708	31,066	$3.85	$119,697,627
Jan-11	Rest-of-Pool	32,883	1,490	0	181	1,661	32,702	24,708	31,041	$3.87	$119,986,735
Feb-11	Rest-of-Pool	32,883	2,440	0	180	1,661	32,702	24,708	31,041	$3.88	$120,428,082

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
Mar-11	Rest-of-Pool	32,814	2,156	1,400	180	1,593	34,034	24,708	31,041	$3.89	$120,817,297
Apr-11	Rest-of-Pool	32,818	2,156	1,400	264	1,593	33,954	24,708	30,961	$3.92	$121,289,058
May-11	Rest-of-Pool	32,818	2,206	1,400	264	1,593	33,954	24,708	30,961	$3.92	$121,300,051
Jun-11	Rest-of-Pool	33,322	2,196	911	67	1,696	34,166	26,701	31,560	$3.07	$96,955,564
Jul-11	Rest-of-Pool	33,322	2,196	911	67	1,696	34,166	26,701	31,560	$3.13	$98,866,783
Aug-11	Rest-of-Pool	33,322	2,196	911	67	1,696	34,166	26,701	31,560	$3.27	$103,061,449
Sep-11	Rest-of-Pool	33,322	2,146	911	67	1,696	34,166	26,701	31,560	$3.43	$108,131,252
Oct-11	Rest-of-Pool	33,509	2,186	911	67	1,696	34,353	26,701	31,747	$3.51	$111,359,443
Nov-11	Rest-of-Pool	33,507	2,124	911	67	1,696	34,351	26,701	31,744	$3.51	$111,410,570
Dec-11	Rest-of-Pool	33,507	2,186	911	0	1,696	34,418	26,701	31,811	$3.51	$111,618,814

12.2 PER Adjustment

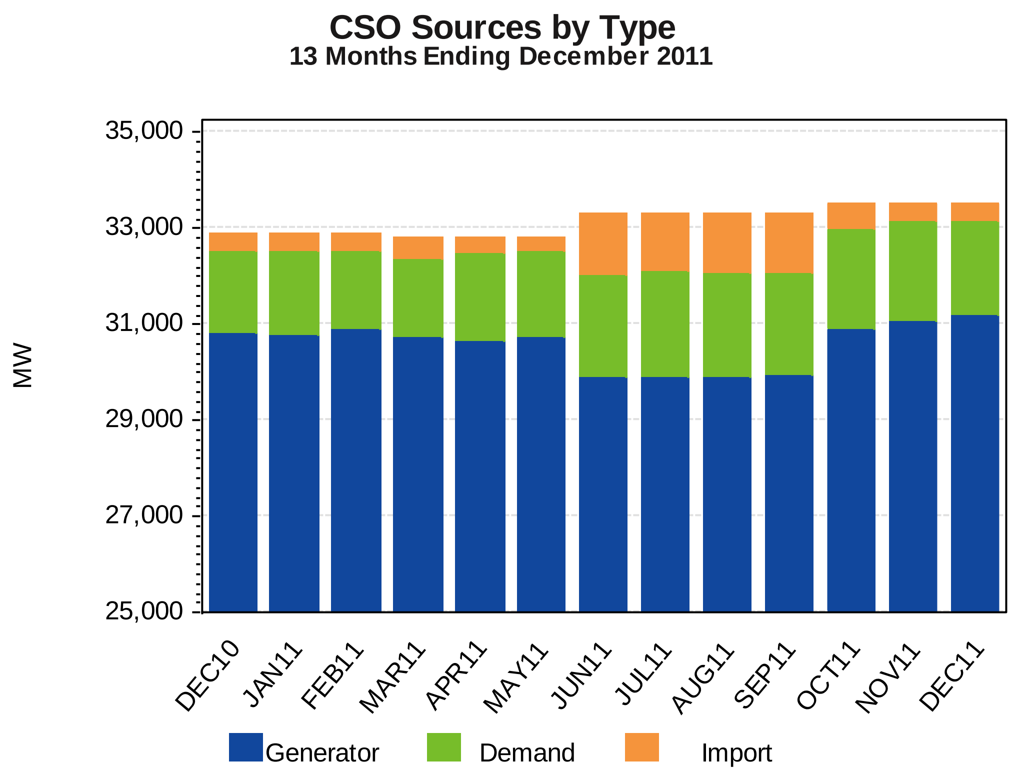
As stated above, Peak Energy Rent is a payment adjustment made to reflect revenues earned by resources during high priced hours in the Energy markets. Generation and Import resources with a CSO are subject to PER adjustments (excluding self-supply CSO MWs). Demand resources are not subject to PER adjustments.

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	HQICC MW (B)	Excess RTEG MW (C)	Self Supply MW (D)	Capacity Req MW (E=A+B-C)	Peak Contrib MW
Dec-10	0	182	1,661	32,727	24,708
Jan-11	0	181	1,661	32,702	24,708
Feb-11	0	180	1,661	32,702	24,708
Mar-11	1,400	180	1,593	34,034	24,708
Apr-11	1,400	264	1,593	33,954	24,708
May-11	1,400	264	1,593	33,954	24,708
Jun-11	911	67	1,696	34,166	26,701
Jul-11	911	67	1,696	34,166	26,701
Aug-11	911	67	1,696	34,166	26,701
Sep-11	911	67	1,696	34,166	26,701
Oct-11	911	67	1,696	34,353	26,701
Nov-11	911	67	1,696	34,351	26,701
Dec-11	911	0	1,696	34,418	26,701

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
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
Sep-11	2,094	29,947	1,281	33,322
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

12.4 Capacity Imports

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

Month	Capacity Zone	NY AC Ties	New Brunswick	HQ Phase I/II	HQ Highgate	Total
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
Sep-11	Rest-of-Pool	392	227	462	200	1,281
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

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
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

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

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 ($)	Performance Incentive ($)
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
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	611.50	-1.94	121.34	-$8,244	$106,802
May-11	REAL_TIME	0	691.11	775.38	-18.92	103.20	-$80,490	$90,830
May-11	REAL_TIME_EG	0	490.11	442.50	-63.14	15.53	-$184,234	$9,378
May-11	SEASONAL_PEAK	0	145.67	220.61	0.00	74.94	$0	$65,959
Jun-11	ON_PEAK	88	617.02	934.34	-9.06	326.38	-$29,329	$222,860
Jun-11	REAL_TIME	0	780.24	900.41	-41.37	161.52	-$129,220	$103,820
Jun-11	REAL_TIME_EG	0	491.84	486.91	-32.81	27.88	-$80,947	$14,173
Jun-11	SEASONAL_PEAK	0	259.66	234.20	-34.32	8.86	-$107,053	$5,697
Jul-11	ON_PEAK	80	617.49	950.08	-5.91	338.50	-$21,154	$322,599
Jul-11	REAL_TIME	6	812.01	769.50	-69.15	26.62	-$215,689	$23,915
Jul-11	REAL_TIME_EG	0	515.76	466.91	-66.59	17.74	-$164,278	$12,572
Jul-11	SEASONAL_PEAK	34	259.66	307.27	-0.28	47.90	-$876	$42,910
Aug-11	ON_PEAK	92	617.86	996.48	-7.83	386.45	-$30,600	$298,434
Aug-11	REAL_TIME	0	738.33	758.09	-50.86	70.51	-$158,651	$51,514
Aug-11	REAL_TIME_EG	0	536.18	466.70	-81.87	12.40	-$201,981	$7,165
Aug-11	SEASONAL_PEAK	0	259.66	307.27	-0.28	47.90	-$876	$34,995
Sep-11	ON_PEAK	0	615.17	956.94	-5.64	347.41	-$19,009	$164,122
Sep-11	REAL_TIME	0	741.29	800.19	-40.10	98.93	-$125,059	$44,062
Sep-11	REAL_TIME_EG	0	477.63	458.67	-34.32	15.36	-$84,667	$5,411

Month	DR Type	Performance Hours	CSO MW	Capacity Value (MW)	Negative Capacity Variance (MW)	Positive Capacity Variance (MW)	Performance Penalty ($)	Performance Incentive ($)
Sep-11	SEASONAL_PEAK	0	259.66	302.87	-1.54	44.75	-$4,788	$19,929
Oct-11	ON_PEAK	0	614.68	956.94	-4.92	347.17	-$16,747	$142,754
Oct-11	REAL_TIME	0	750.30	791.41	-25.82	66.87	-$80,539	$25,919
Oct-11	REAL_TIME_EG	0	479.03	458.67	-36.37	16.02	-$89,730	$4,911
Oct-11	SEASONAL_PEAK	0	259.38	302.87	-1.25	44.75	-$3,911	$17,344
Nov-11	ON_PEAK	0	614.82	956.98	-4.18	346.34	-$14,464	$107,166
Nov-11	REAL_TIME	0	732.01	791.46	-14.42	73.77	-$44,982	$21,514
Nov-11	REAL_TIME_EG	0	476.06	458.67	-33.25	15.86	-$82,030	$3,658
Nov-11	SEASONAL_PEAK	0	259.38	302.87	-1.25	44.75	-$3,911	$13,049
Dec-11	ON_PEAK	42	613.14	1,178.70	-3.86	569.42	-$12,383	$362,546
Dec-11	REAL_TIME	3	631.85	553.87	-113.09	35.10	-$352,718	$19,736
Dec-11	REAL_TIME_EG	0	438.59	430.71	-42.46	34.58	-$104,759	$15,378
Dec-11	SEASONAL_PEAK	0	259.38	405.47	-3.89	149.98	-$12,130	$84,330

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").

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
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
May-11	2,982.10	1,414.26	$83,368	0.00	0.00	$0	DRP
Jun-11	4,702.20	2,950.49	$212,203	0.00	0.00	$0	DRP
Jul-11	12,058.80	14,379.19	$1,814,145	0.00	0.00	$0	DRP
Aug-11	6,781.30	6,592.00	$413,676	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
Sep-11	6,072.90	5,399.15	$292,987	0.00	0.00	$0	Initial
Oct-11	7,253.00	10,681.24	$551,256	0.00	0.00	$0	Initial
Nov-11	317.40	1,054.09	$59,600	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
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	DRP
Apr-11	346.16	$34,616	DRP
May-11	0.00	$0	DRP
Jun-11	128.09	$12,991	DRP
Jul-11	1,062.90	$164,497	DRP
Aug-11	223.89	$28,389	DRP
Sep-11	3.60	$363	Initial
Oct-11	0.00	$0	Initial
Nov-11	19.25	$2,097	Initial

14. Document History

Date	Version	Description
1/18/2012	Rev. 1	Updated the Demand Resource performance table in section 12.5.2.
1/17/2012	Original Posting	