

NEPOOL Participants Committee Report September 2010

Vamsi Chadalavada

Senior Vice President and Chief Operating Officer

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Highlights

- **Day-Ahead (DA), Real-Time (RT) Prices and Transactions**
 - August natural gas prices over the period were 7.1% lower while oil prices were 3.3% higher than July 2010 average values
 - Average RT Hub Locational Marginal Prices (LMPs) over the period were down 7.2% from July 2010 averages

Underlying natural gas data furnished by:



Highlights (cont'd.)

- **Daily Net Commitment Period Compensation (NCPC)***
 - August payments total \$11.7M over the period, down \$7.7M from July
 - First Contingency payments total \$10.2M, down \$6.1M from July
 - \$9.1M paid to internal resources, down \$6.8M from July
 - \$961K charged to DA Load Obligations (DALO), \$8.1M to RT Deviations
 - \$1.2M paid to resources at external locations, up \$724K from July
 - \$1.1M charged to DALO at external locations, \$59K to RT Deviations
 - Second Contingency payments total \$92K, up \$57K from the July total of \$35K
 - Voltage payments total \$936K, down \$1.4M from July
 - Distribution payments total \$415K, down \$347K from July
 - NCPC payments as percent of Energy Market value were 1.7%

* Total includes NCPC payments to eligible resources at external locations.

Highlights (cont'd.)

- The Regional System Plan (RSP) Public Meeting will be held on September 16 and will feature two panel sessions
- A number of Planning Advisory Committee (PAC) meetings are scheduled for this fall covering multiple topics of interest. Discussion on Non Transmission Alternatives planned for RSP 11 is scheduled for October and the New England Wind Integration Study is scheduled for November

Eastern Interconnection Planning Collaborative (EIPC)

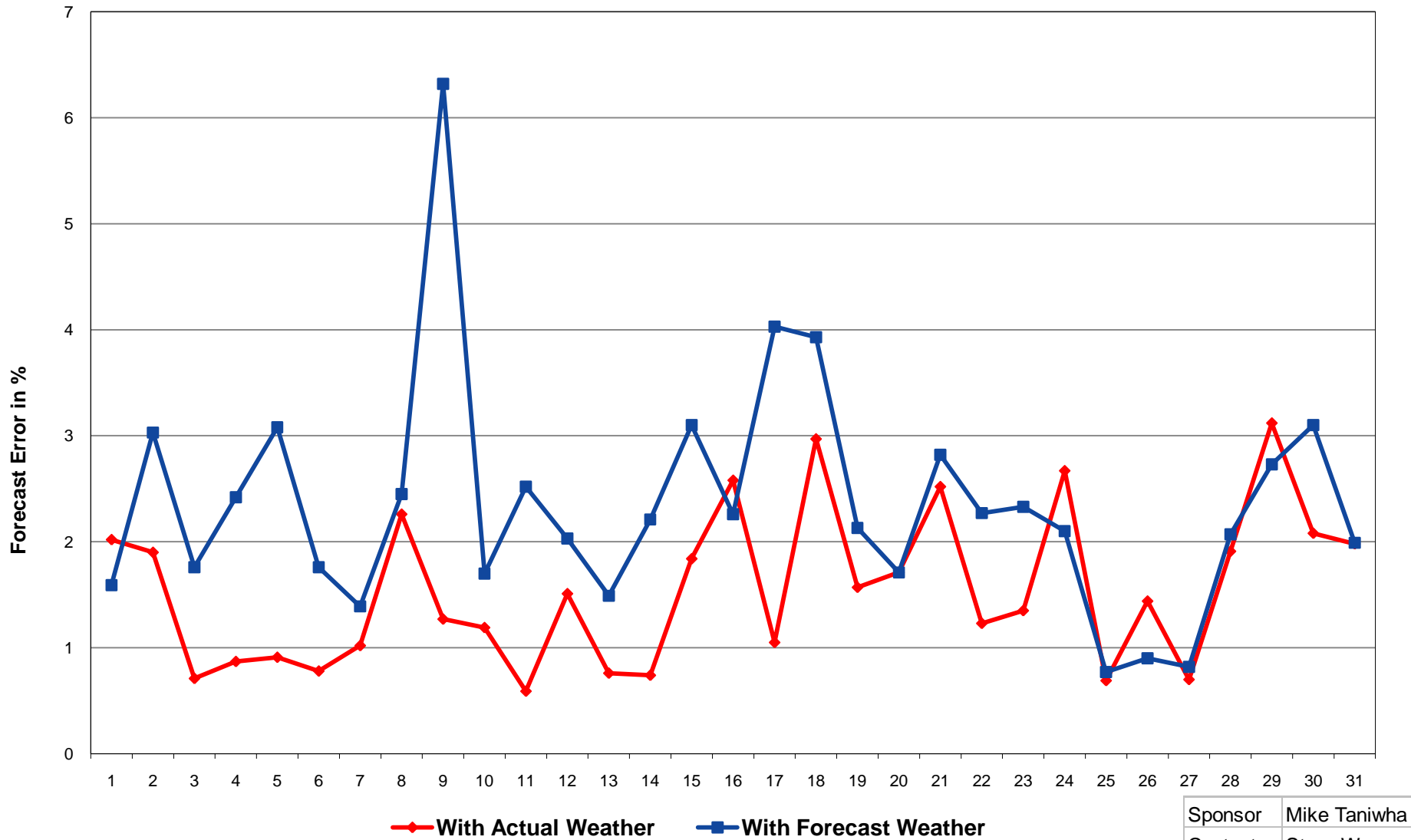
- Stakeholder Steering Committee has formed working groups to support their efforts
 - Modeling Working Group
 - Roll-up Working Group
 - Scenario Planning Working Group
 - Governance Task Force
- Several New England representatives have volunteered for the working groups
- Initial efforts are to establish ground rules and confirm objectives
- An EIPC representative will attend each working group meeting
- Information on the working groups, including high-level meeting notes, will be posted at www.eipconline.com

Highlights (cont'd.)

- August ended and Sept. started with another heat wave
 - Monthly Peak Load of 25,885 MW on August 31
 - All-time September Peak Load of 26,098 MW on Sept 2
- A large generation trip occurred on Thursday, Sept 2 @ 13:09 PM
 - LMP's were over \$1000 for 20 minutes
 - Experienced difficulty recovering from the large contingency and Area Control Error deviation given the high loads and insufficient system flexibility on that day
 - Interface with New York was already loaded and the ISO could not fully use the 'Shared Activation of Reserves' procedure
 - The ISO is conducting a detailed analysis of this event and will report back at a future NEPOOL RC/PC meeting

Daily Average Load Forecast Percent Error - August 2010

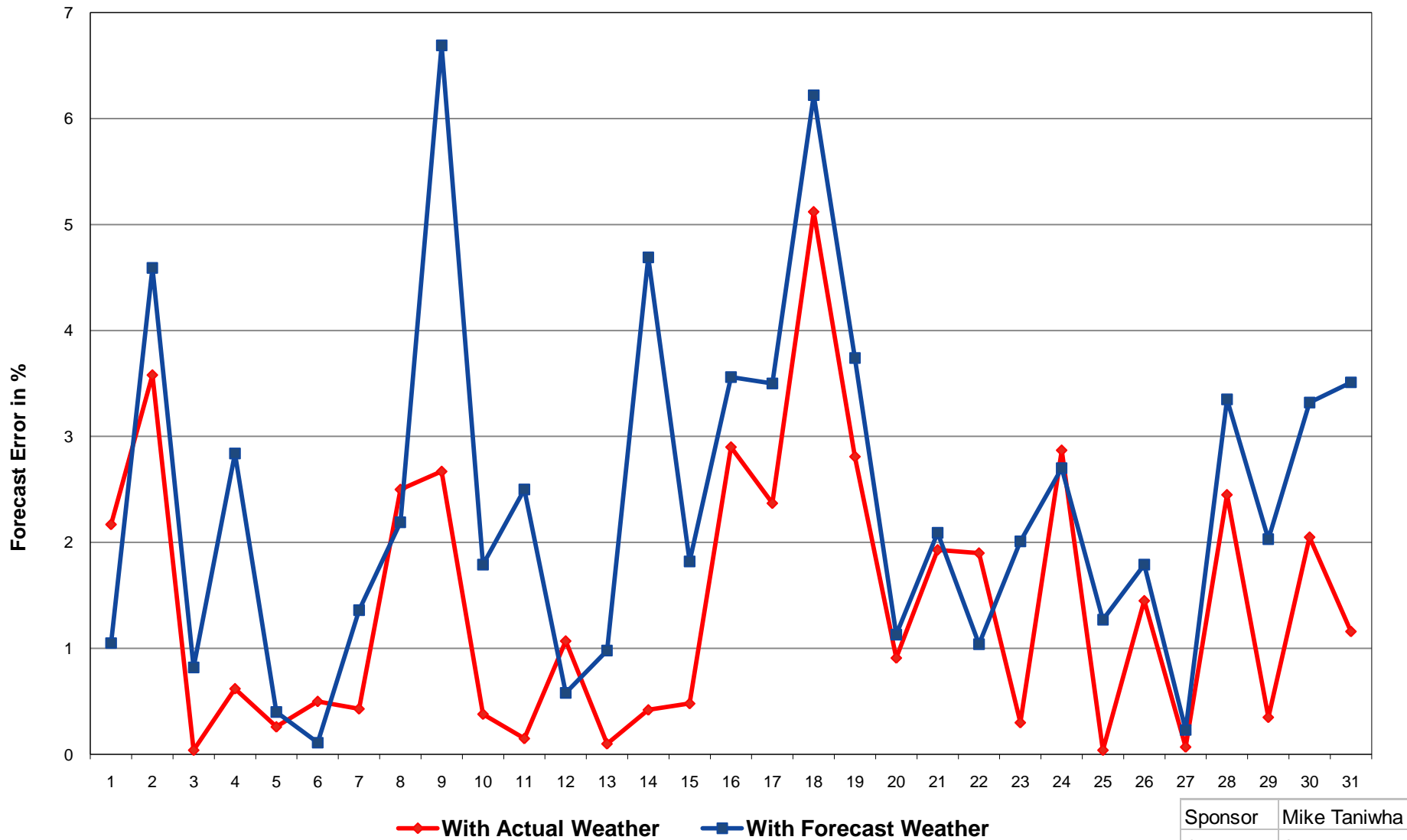
Monthly Average Error was 2.4% with Forecast Weather and 1.5% with Actual Weather



Sponsor	Mike Taniwha
Contact	Steve Weaver

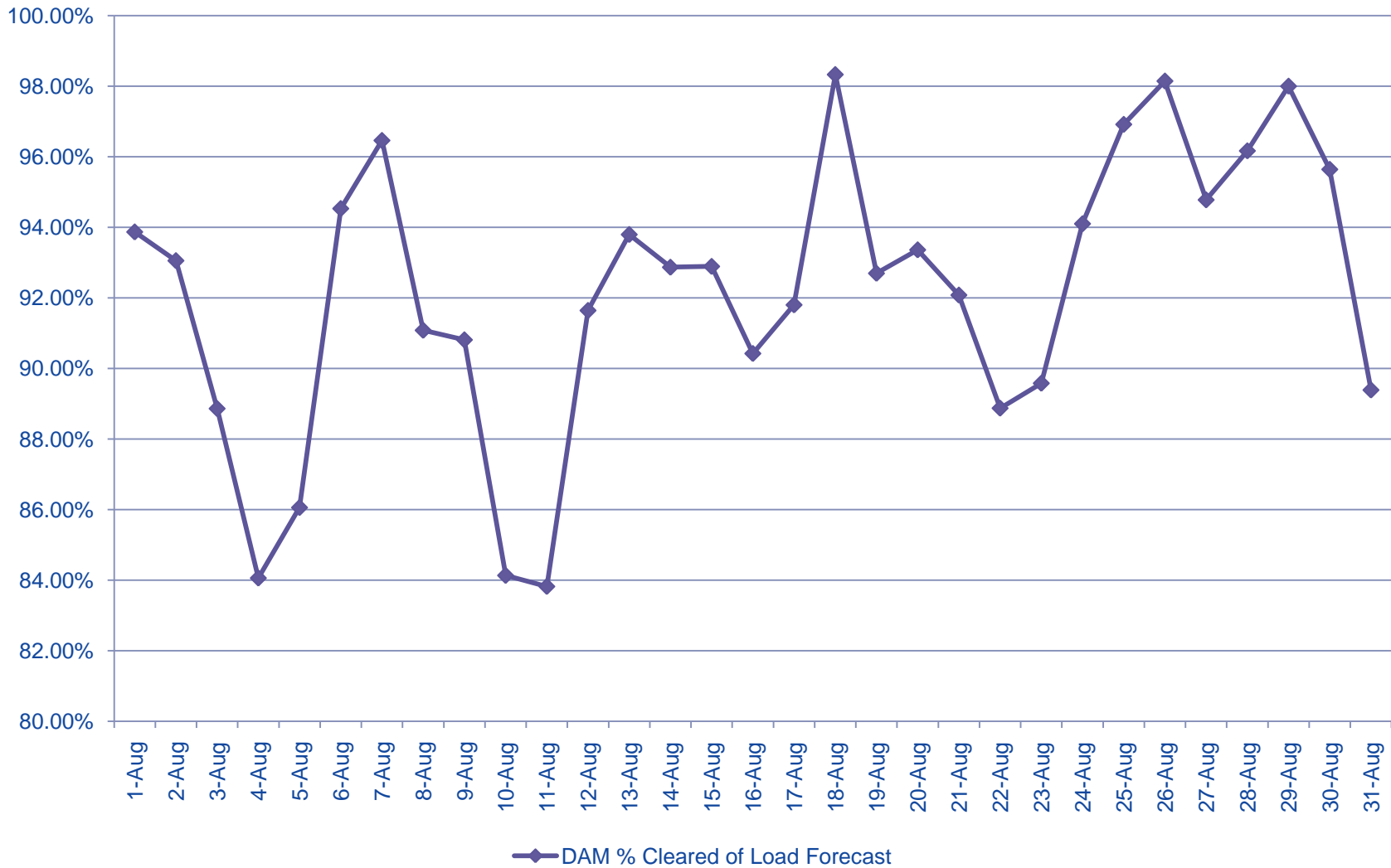
Load Forecast Percent Error at Hour of Daily Peak - August 2010

Monthly Average Error was 2.4% with Forecast Weather and 1.4% with Actual Weather



Sponsor	Mike Taniwha
Contact	Steve Weaver

August 2010 - Percent of Day Ahead Forecasted Peak that Cleared in the Day Ahead Market



System Operations

System Operations

<u>Weather Patterns:</u>	Boston	Temperature – Average Precipitation – Above Average	Hartford	Temperature – Much above Avg* Precipitation – Below Average * (6 degrees above normal)
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<u>Peak Load:</u>	25,885MW	August 31, 2010	17:00
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<u>Minimum Generation Emergencies :</u> Aug 19, Aug 24, Aug 29

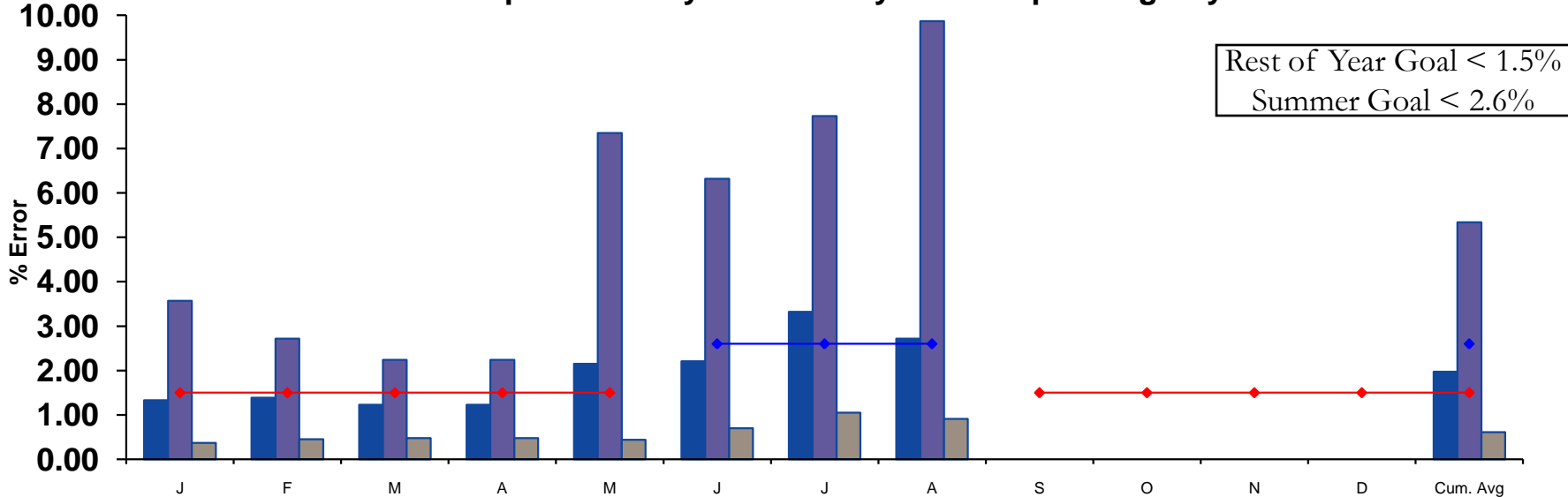
<u>M/LCC2:</u>
08/09 - Due to a Capacity Deficiency, 08/31 – Due to a Capacity Deficiency

<u>OP-4 :</u>
08/09- Due to a Capacity Deficiency, Loads were 2200 MW over the forecasted curve on peak.
Implemented Action 1 only.

<u>NPCC Shared Activation of Reserve Events:</u>		
August 05	ISO-NE	550MW
August 08	IESO	800MW
August 11	PJM	1296MW

2010 System Operations - Load Forecast Accuracy

All Hours
Monthly Average, Daily Maximum and Minimum,
Based on forecast published by 1000 on day before Operating Day



Rest of Year Goal < 1.5%
 Summer Goal < 2.6%

■ Mo. Avg
 ■ Day Max
 ■ Day Min
 ◆ Summer Goal
 ◆ Rest of Year Goal

	J	F	M	A	M	J	J	A	S	O	N	D	Avg	
Mo Avg	1.33	1.39	1.31	1.23	2.15	2.21	3.32	2.72					1.97	Mo Avg
Day Max	3.57	2.72	2.62	2.24	7.35	6.32	7.73	9.87					5.34	Day Max
Day Min	0.37	0.45	0.43	0.48	0.44	0.70	1.05	0.91					0.61	Day Min
Summer Goal						2.60	2.60	2.60						
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50		
Current YTD ROY Avg.													1.49	
Summer Average													2.75	

Contact: Steve Weaver

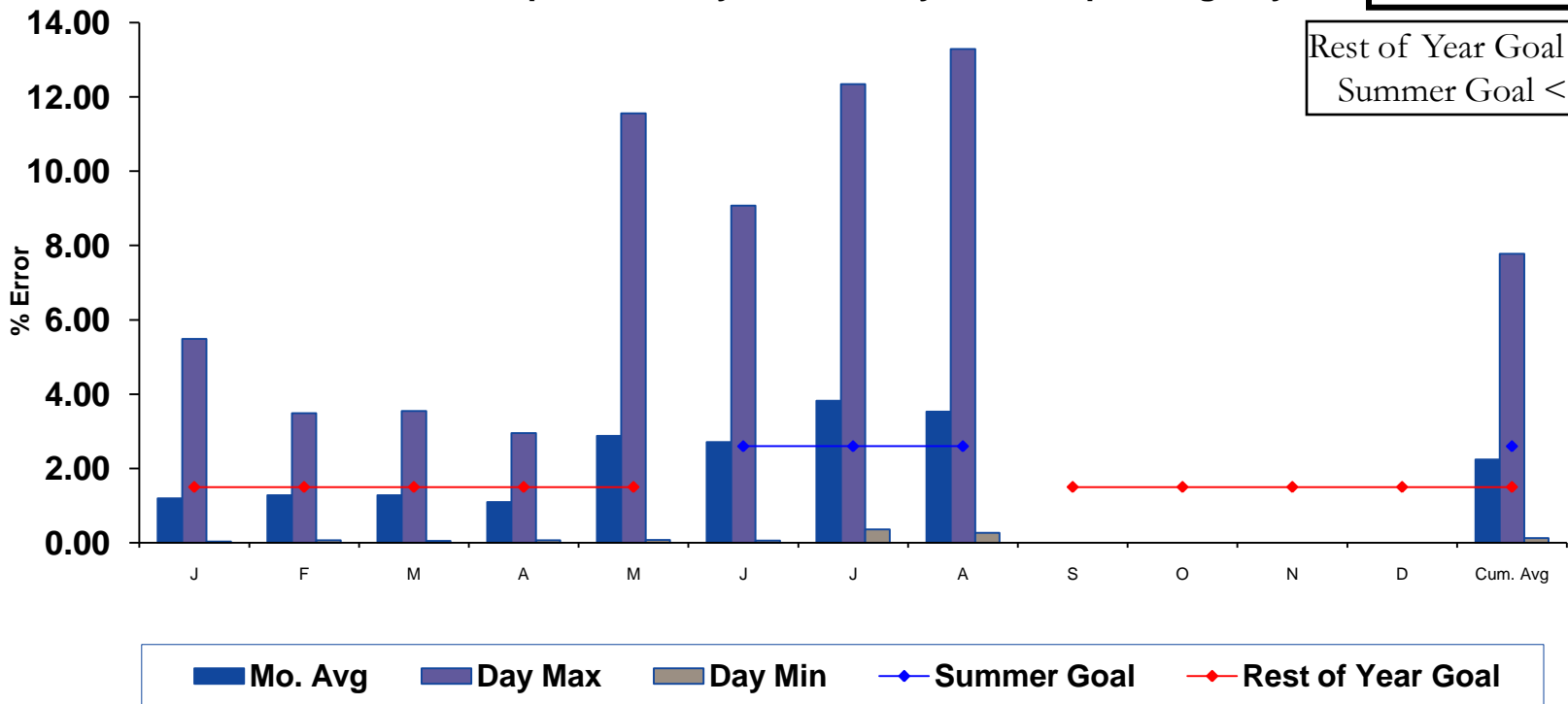
Summer Goal = 2.6% Rest of Year(ROY) Goal = 1.5%
 Summer consists of June, July and August-

2010 System Operations - Load Forecast Accuracy cont.

Peak Hours
Monthly Average, Daily Maximum and Minimum
 Based on forecast published by 1000 on day before Operating Day

Dashboard Indicator 

Rest of Year Goal < 1.5%
 Summer Goal < 2.6%



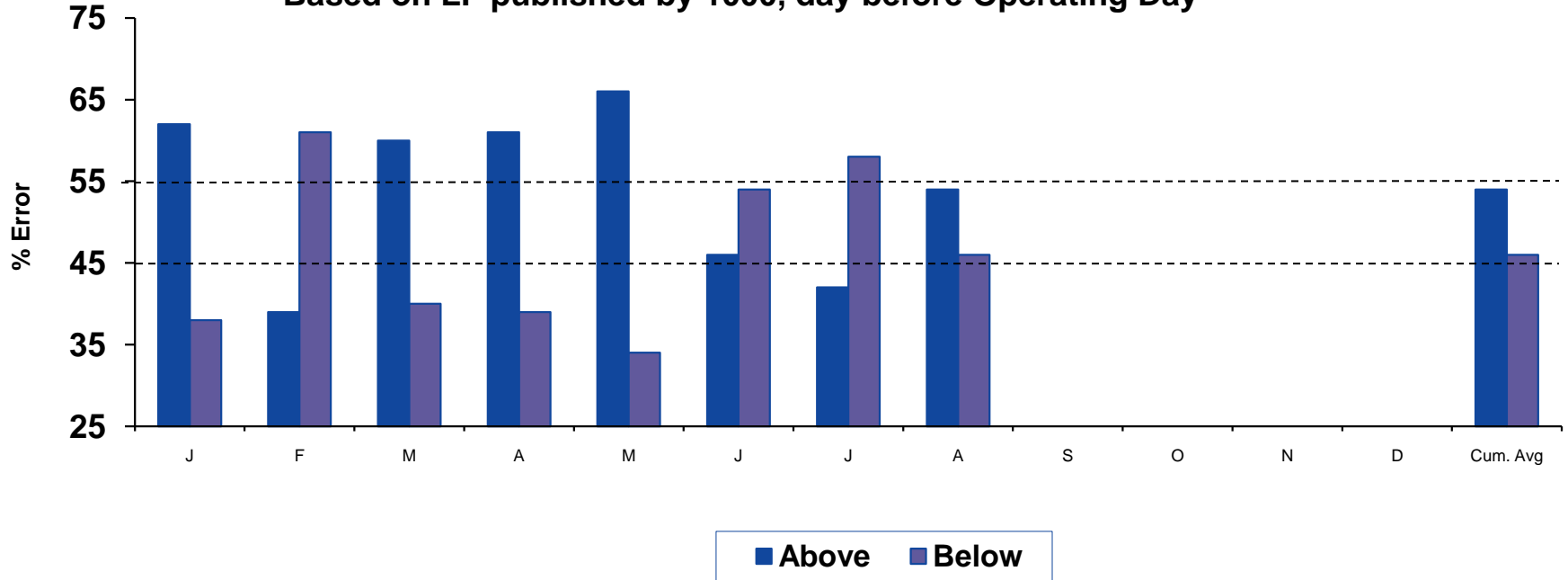
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.20	1.28	1.28	1.10	2.88	2.71	3.82	3.53					2.24
Day Max	5.49	3.49	3.55	2.95	11.56	9.07	12.34	13.29					7.78
Day Min	0.03	0.07	0.05	0.07	0.08	0.06	0.36	0.27					0.13
Summer Goal						2.6	2.6	2.6					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Current YTD ROY													1.55
Summer Average													3.35

Contact: Steve Weaver													
Summer Goal = 2.6%	Rest of Year(ROY) Goal = 1.5%												
Summer consists of June, July and August.													

2010 System Operations - Load Forecast Accuracy

Target = 50%
Plus/Minus 5%

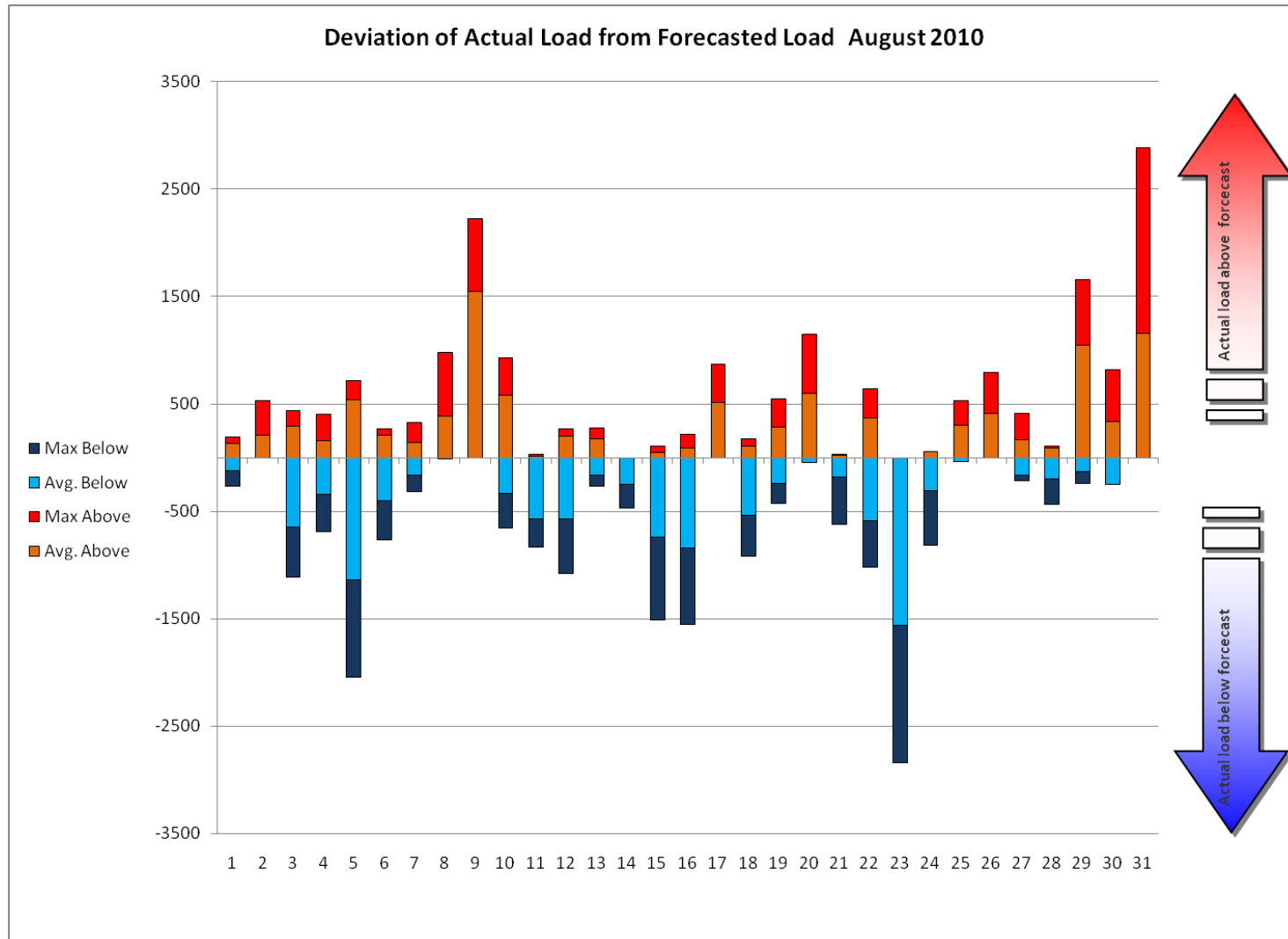
**Percent of Hours Actual Load
Above vs. Below Forecast**
Based on LF published by 1000, day before Operating Day



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	62.0	39.0	60.0	61.0	66.0	46.0	42.0	54.0					54.0
Below %	38.0	61.0	40.0	39.0	34.0	54.0	58.0	46.0					46.0
Avg Above	178.0	106.0	144.0	147.0	258.0	198	327	329.0					171.0
Avg Below	-112.0	-181.0	-118.0	-103.0	-155.0	-314	-533	-340.0					-189.0
Avg All	74.0	-69.0	38.0	45.0	107.0	-91.0	-166.0	8.0					-7.0

Percent of hours during the month that the actual load was above versus below the forecast													
Sponsor:	Michael Taniwha												
Contact:	Steve Weaver												

2010 System Operations - Load Forecast Accuracy

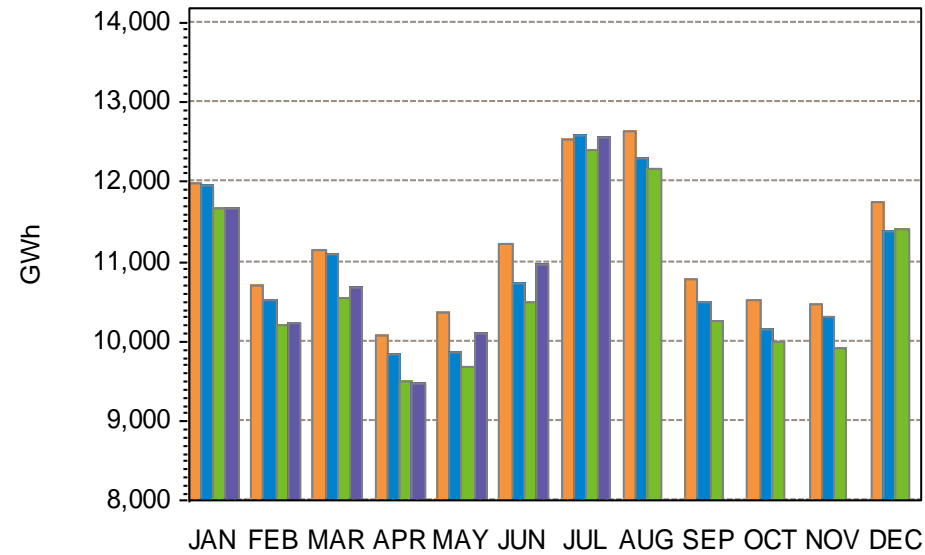
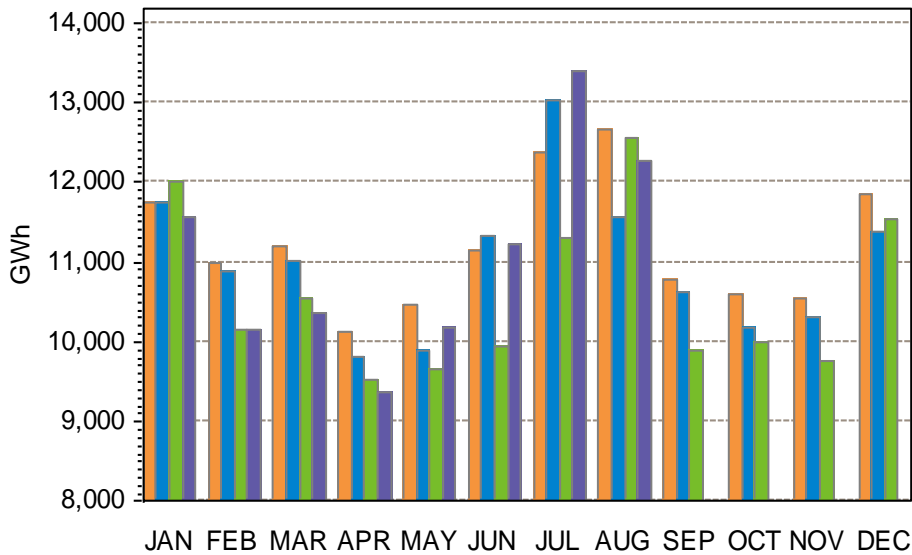


Sponsor	Mike Taniwha
Contact	Steve Weaver

Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

Net Energy for Load (NEL)

Weather Normalized NEL



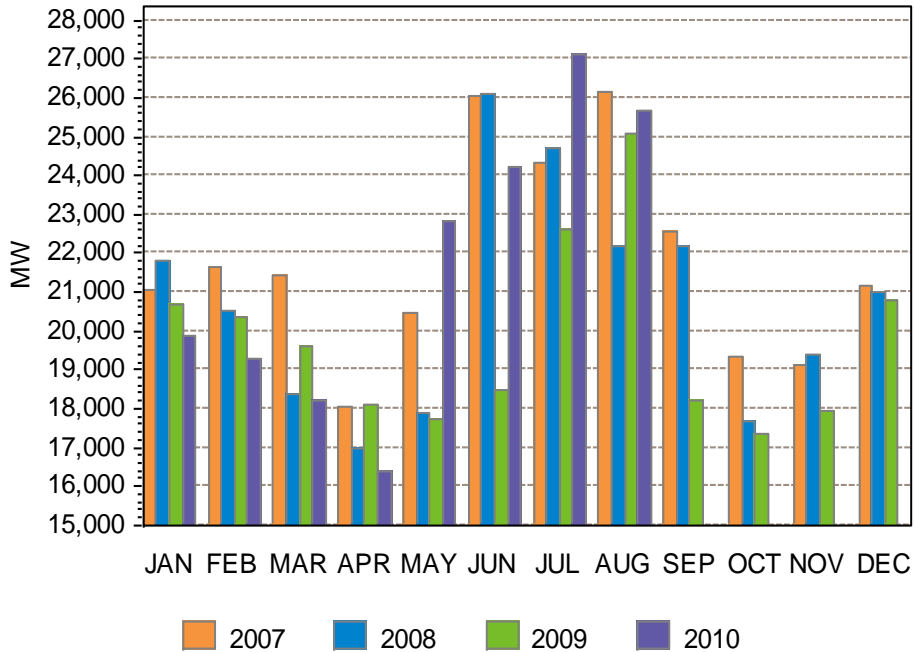
■ 2007 ■ 2008 ■ 2009 ■ 2010
 Ann Tot (TWh): 134E3 132E3 127E3 88473

■ 2007 ■ 2008 ■ 2009 ■ 2010
 Ann Tot (TWh): 134.2 131.2 128.3 75.7

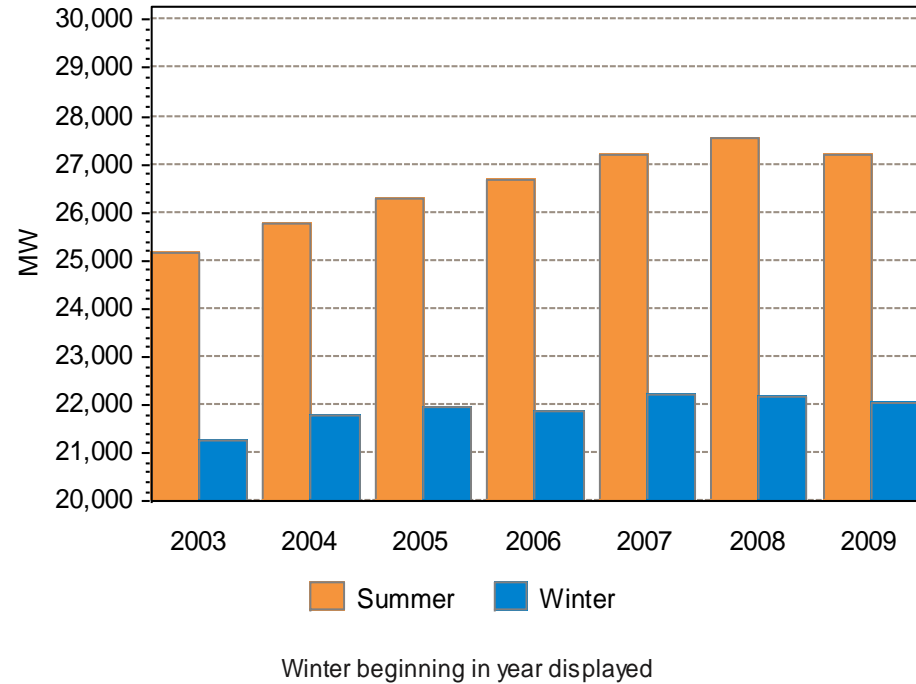
NEPOOL NEL is the total net energy required to serve load for the month, in GWh. NEL is calculated as:
 Generation – pumping load + net interchange.
 Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History

System Peak Load

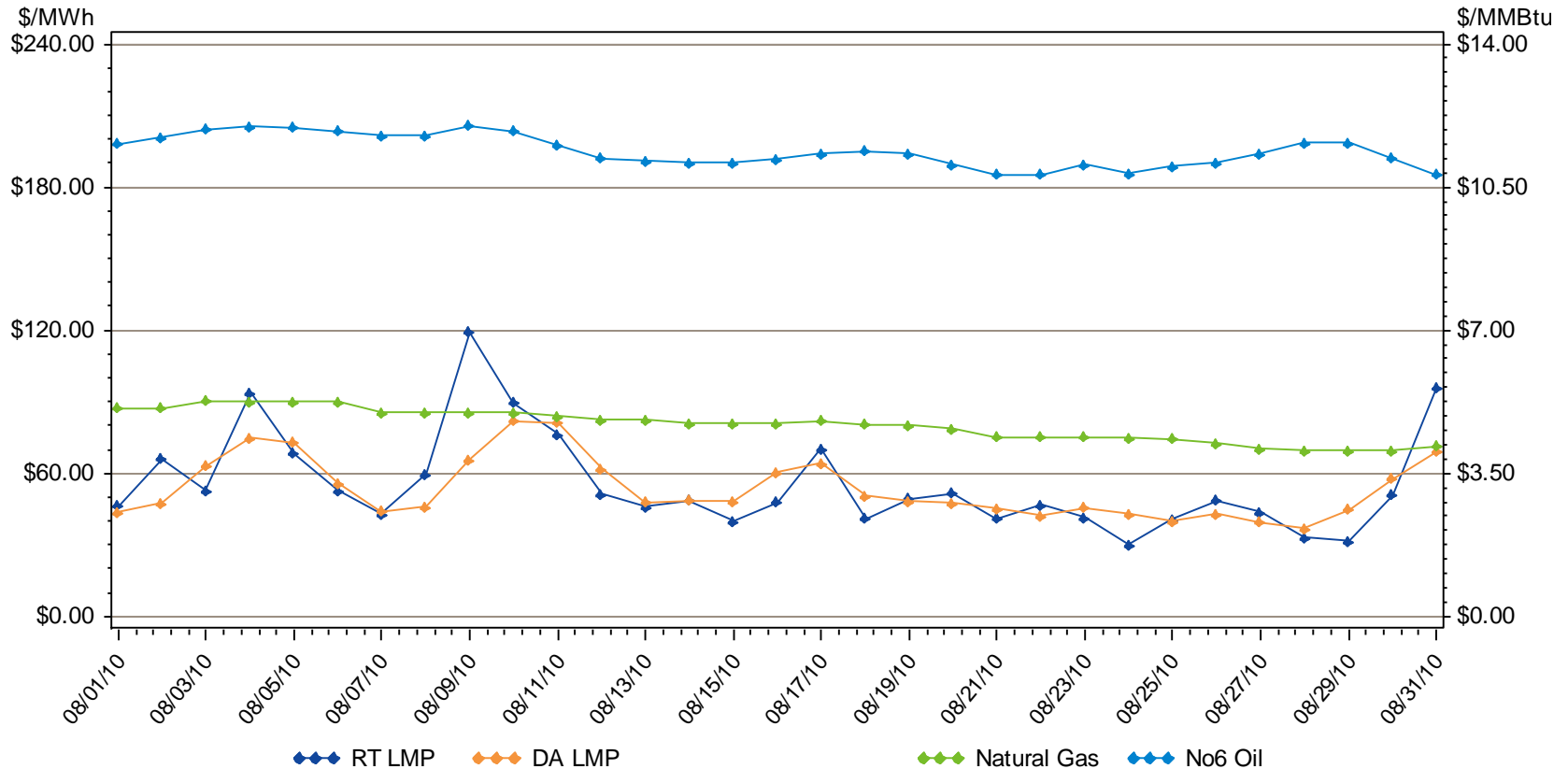


Weather Normalized Seasonal Peaks



Market Operations

DA and RT ISO-NE Hub Prices and Input Fuel Prices: August 1-31, 2010



Underlying natural gas data furnished by:

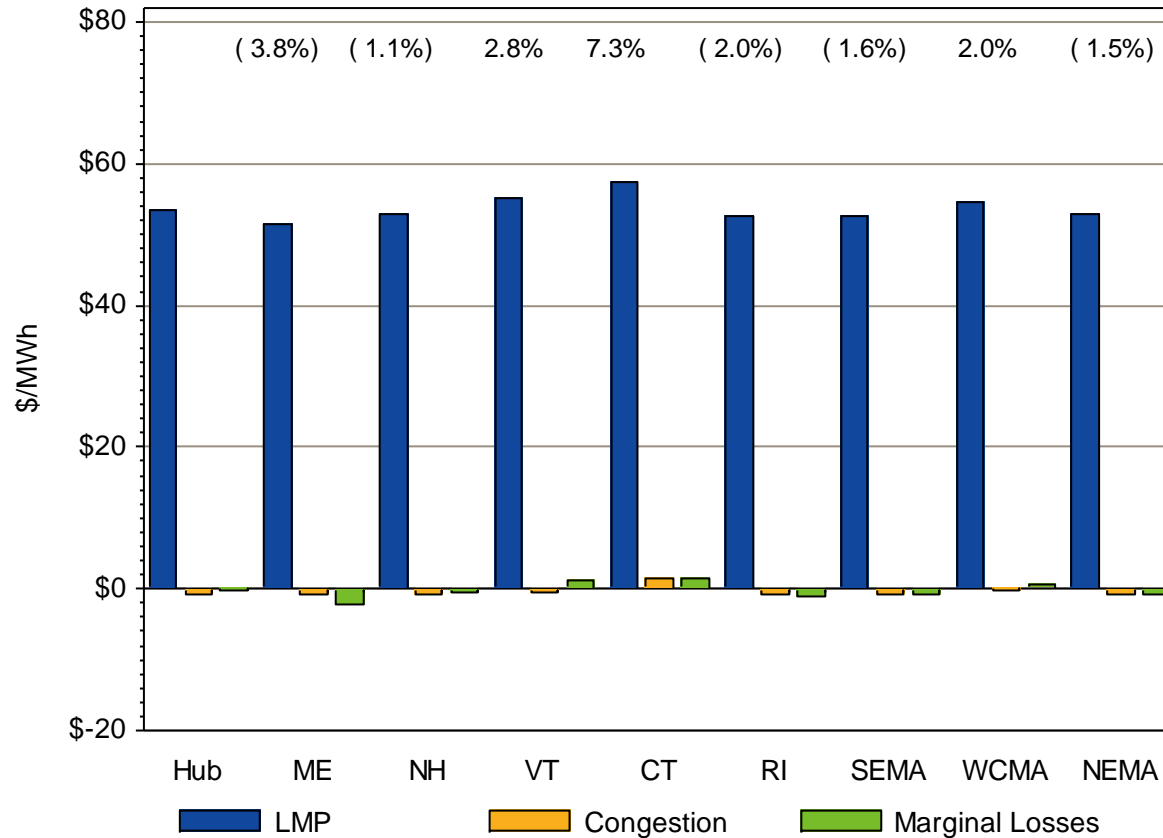


Average price difference over this period (DA-RT): \$-1.85
 Average price difference over this period ABS(DA-RT): \$9.04

Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 16%

Gas price is average of Massachusetts delivery points; No6 Oil is New York Spot Price from DOE's Energy Information Administration

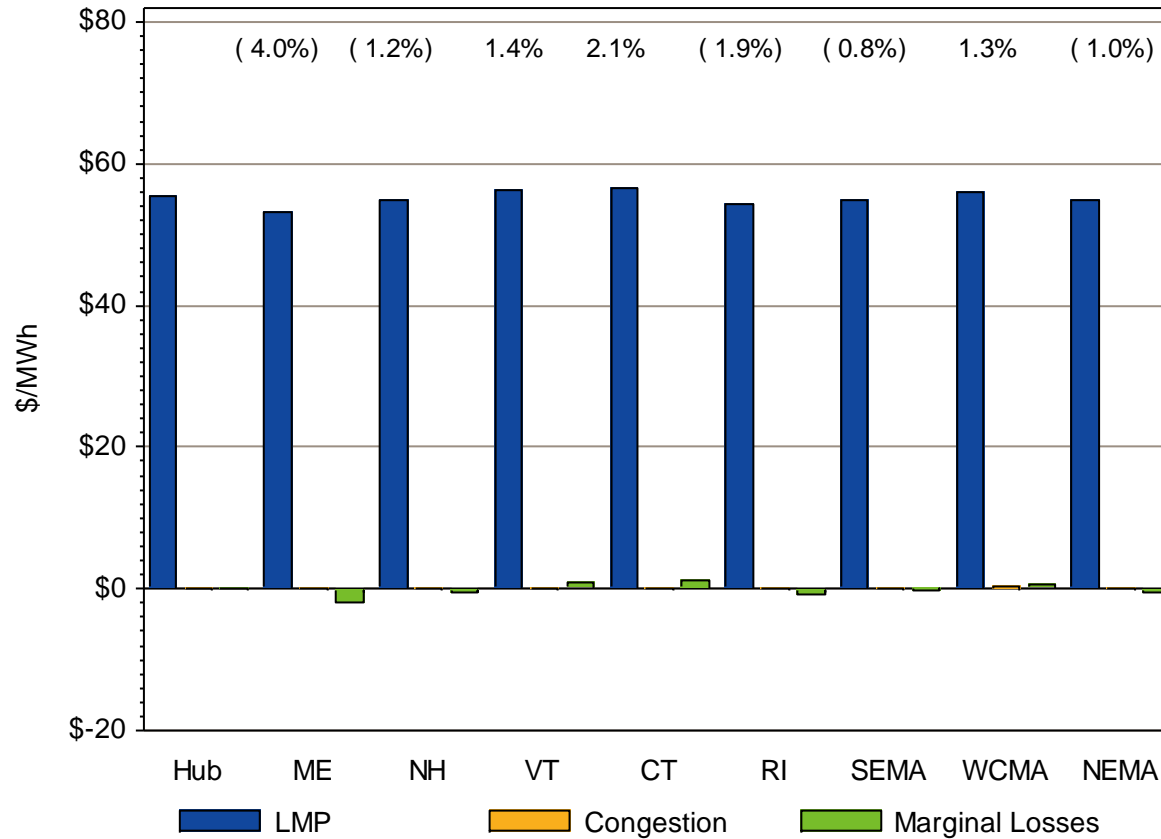
DA LMPs Average by Zone & Hub – August 2010



ME - Maine
 NH - New Hampshire
 VT - Vermont
 CT - Connecticut

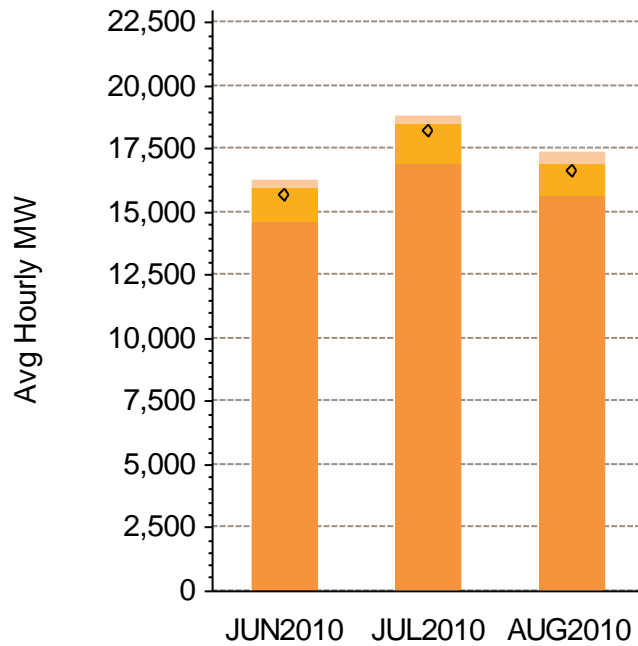
RI - Rhode Island
 SEMA - Southeastern Massachusetts
 WCMA - Western/Central Massachusetts
 NEMA - Northeastern Massachusetts

RT LMPs Average by Zone & Hub – August 2010



Components of Cleared DA Supply and Demand – Last Three Months

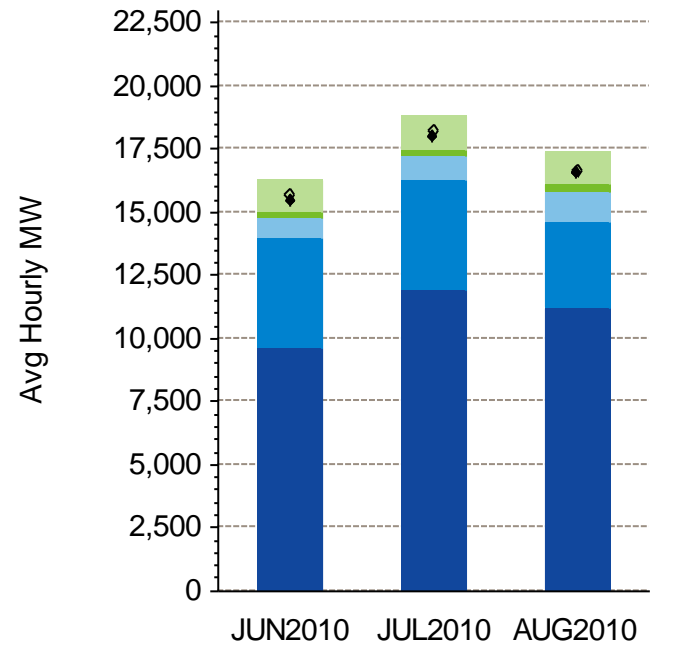
Supply



■ Gen ■ Incs
■ Imports ◆ DA Fcst Load

Gen – Generation
 Incs – Increment Offers
 DA Fcst Load – Day-Ahead Forecast Load

Demand

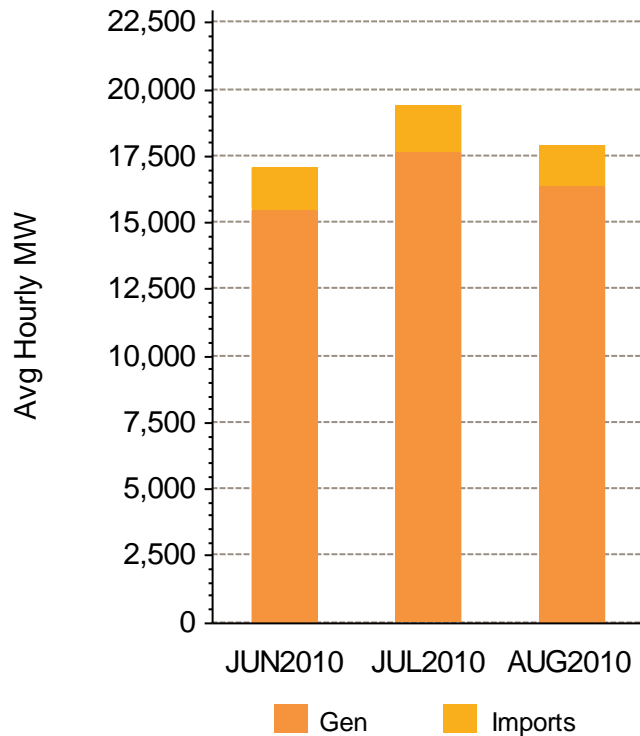


■ Fixed Dem ■ PrSens Dem ■ Decs
■ Losses ■ Exports ◆ Act Load

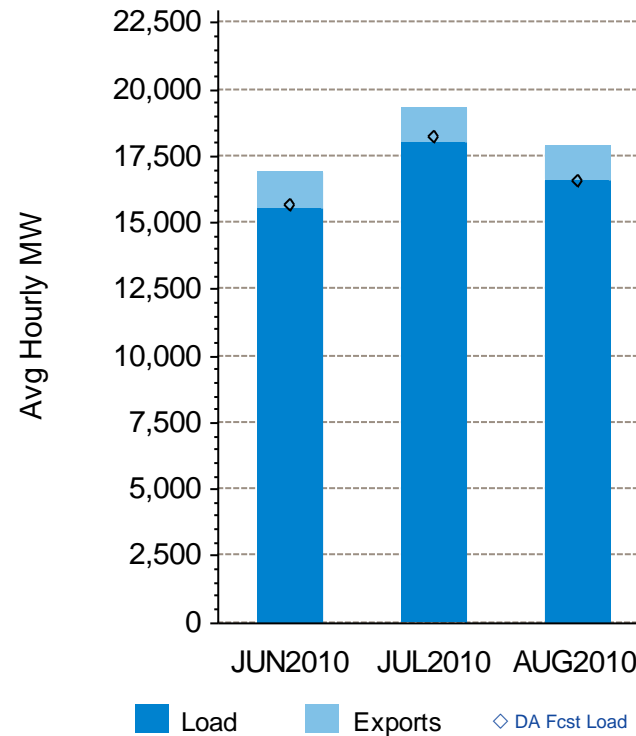
Fixed Dem – Fixed Demand
 PrSens Dem – Price Sensitive Demand
 Decs – Decrement Bids
 Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months

Supply

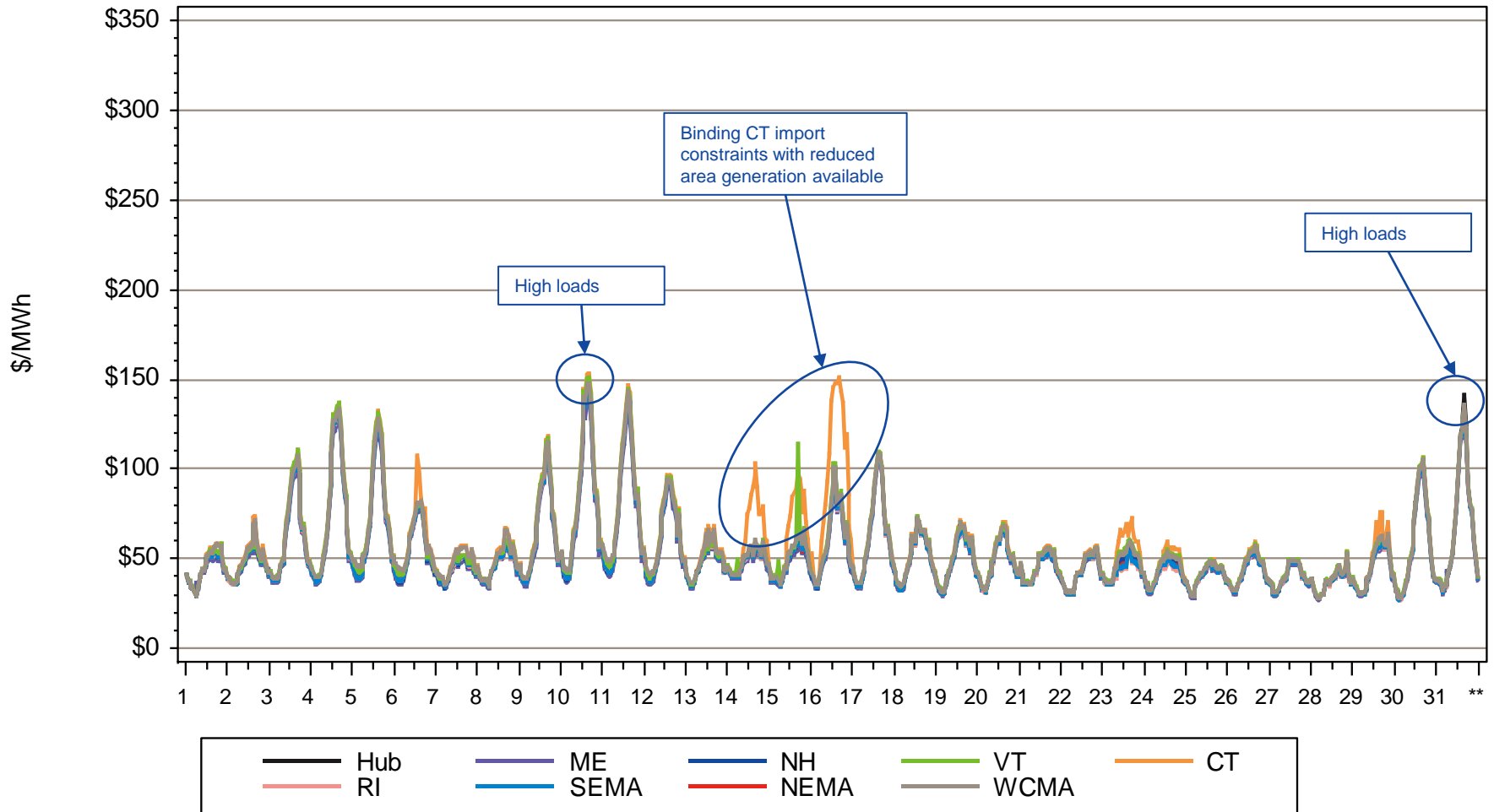


Demand



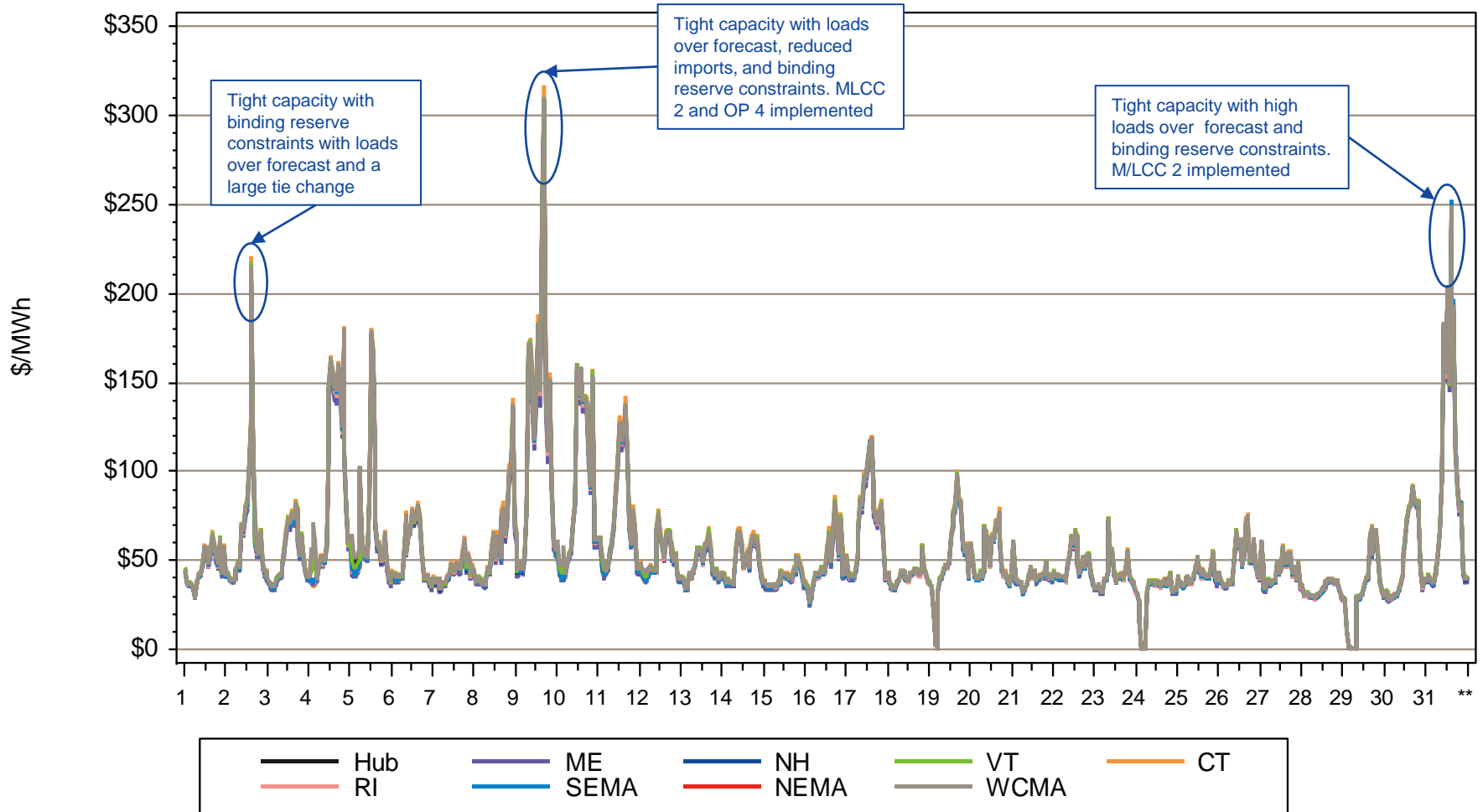
Hourly DA LMPs, August 1-31, 2010

Hourly Day-Ahead LMPs

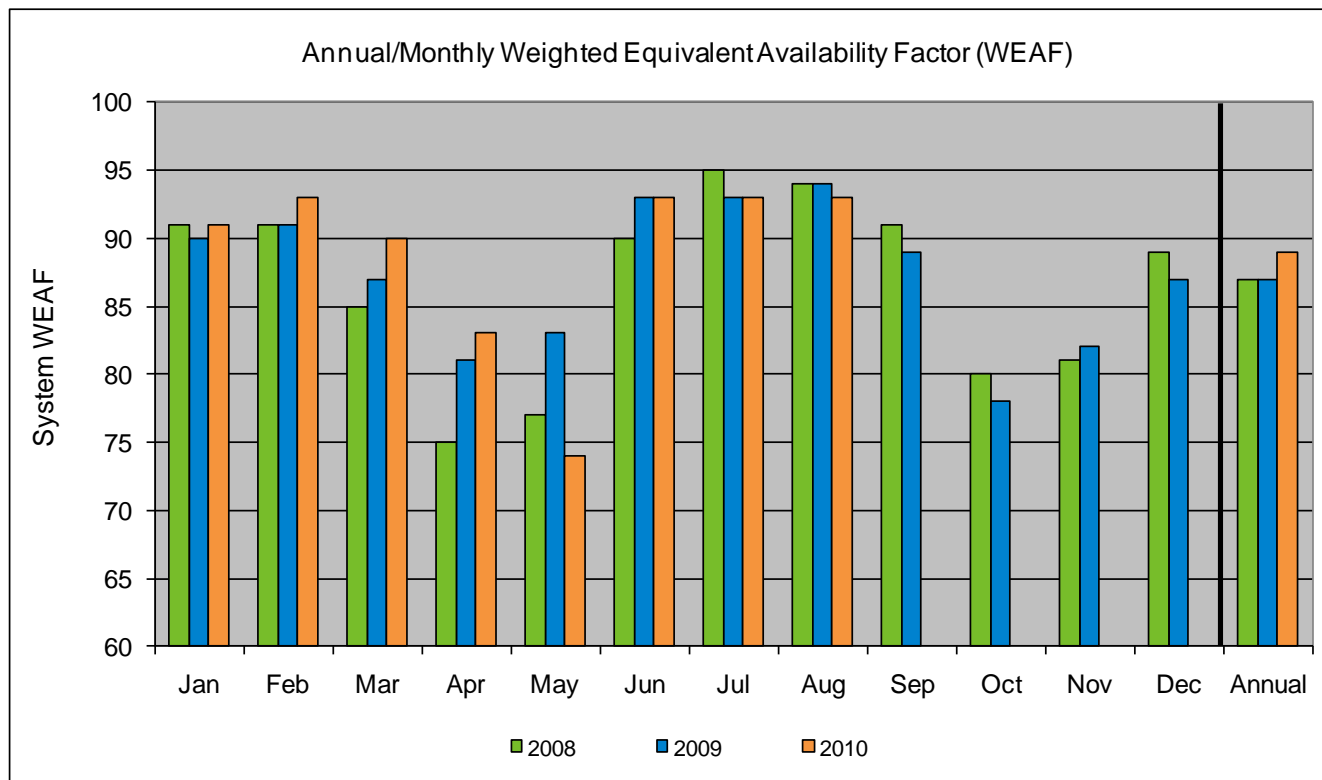


Hourly RT LMPs, August 1-31, 2010

Hourly Real-Time LMPs



System Unit Availability



Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	YTD	
91	93	90	83	74	93	93	93					89	2010
												87	2009
												87	2008
												90	2007

Back-up Detail

Load Response

Net Capacity Supply Obligation (CSO) MW by Demand Resource Type for August 2010

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	161.35	17.33	19.83	0.00	198.51
NH	28.68	21.57	32.42	0.00	82.67
VT	23.71	12.97	41.74	0.00	78.42
CT	223.04	249.85	56.81	108.53	638.24
RI	27.26	38.98	34.46	0.00	100.71
SEMA	42.83	35.64	62.10	0.00	140.57
WCMA	81.28	55.21	56.60	9.48	202.55
NEMA	69.17	61.47	97.67	0.00	228.31
Total	669.41	522.39	406.24	118.01	1,716.05

* Real-Time Demand Response

** Real-Time Demand Response with Emergency Generation

NOTE: Net CSO values include T&D loss factor (8%) and reserve margin gross-up (14.3%)

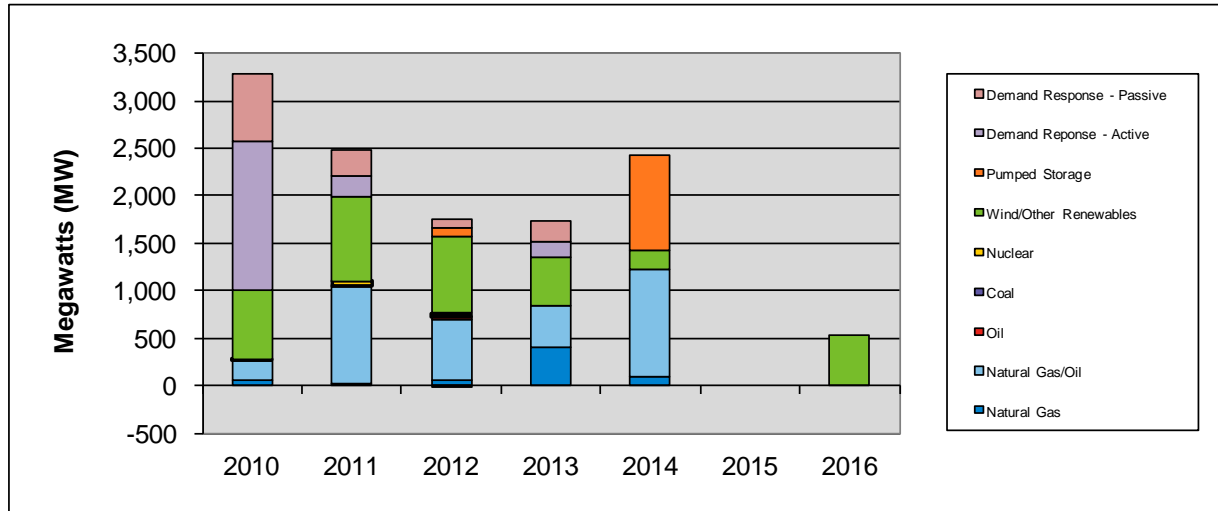
New Generation

New Generation Update

- No new generation projects have applied for interconnection study since the last update
- One project went commercial and two projects withdrew from the queue, resulting in a net decrease in new generation projects of 93 MW
- In total, 83 generation projects are currently being tracked by the ISO, totaling approximately 8,700 MW*

* In the case where a project involves the retirement of a companion unit, only the net MW increase is reported

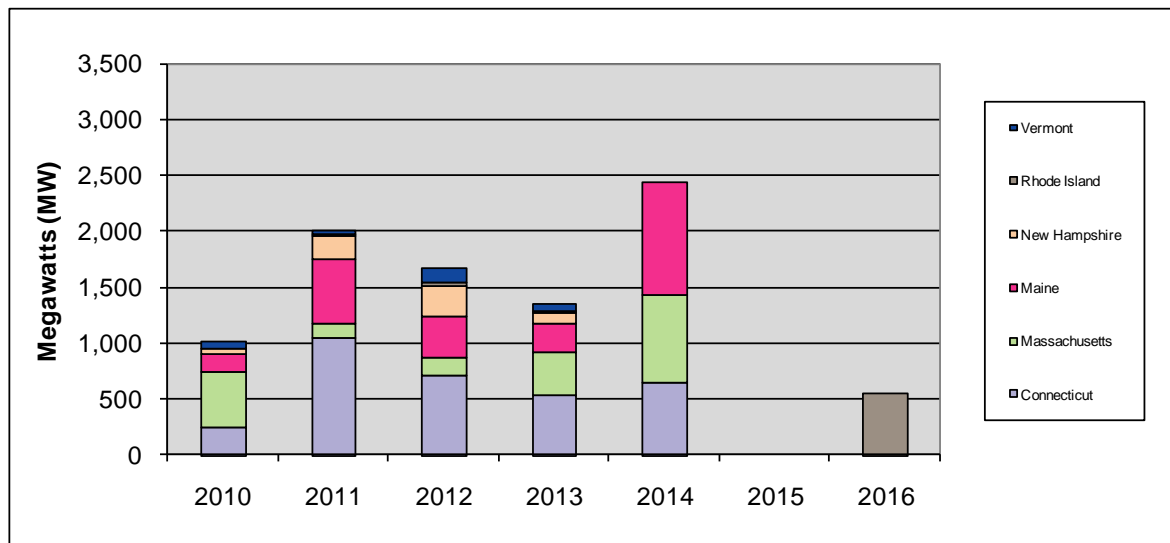
Actual and Projected Annual Capacity Additions By Supply Fuel Type and Demand Resource Type



	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Demand Response - Passive	700	278	95	225	0	0	0	1,298	10.6
Demand Response - Active	1,579	221	-6	169	0	0	0	1,963	16.0
Pumped Storage	0	0	86	0	1,000	0	0	1,086	8.9
Wind & Other Renewables	718	888	813	494	188	0	536	3,637	29.7
Nuclear	0	45	0	0	0	0	0	45	0.4
Coal	17	0	36	0	0	0	0	53	0.4
Oil	0	13	30	0	0	0	0	43	0.4
Natural Gas/Oil	218	1,018	640	444	1,131	0	0	3,451	28.2
Natural Gas	54	31	60	411	107	0	0	663	5.4
Totals	3,286	2,494	1,754	1,743	2,426	0	536	12,239	100.0

- 2010 values include the 293 MW of generation that has gone commercial in 2010
- Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources

Actual and Projected Annual Generator Capacity Additions By State



	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Vermont	61	25	129	64	0	0	0	279	3.1
Rhode Island	0	12	34	29	0	0	536	611	6.8
New Hampshire	51	218	267	94	0	0	0	630	7.0
Maine	162	569	377	251	1,000	0	0	2,359	26.3
Massachusetts	492	128	158	380	791	0	0	1,949	21.7
Connecticut	241	1,043	700	531	635	0	0	3,150	35.1
Totals	1,007	1,995	1,665	1,349	2,426	0	536	8,978	100.0

- 2010 values include the 293 MW of generation that has gone commercial in 2010

New Generation Projection By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	14	462	1	38	13	424
Coal	1	36	0	0	1	36
Hydro	7	1,215	0	24	7	1,191
Landfill Gas	1	34	0	0	1	34
Natural Gas	9	632	0	0	9	632
Natural Gas/Oil	13	3,233	3	943	10	2,290
Nuclear Uprates	2	45	0	0	2	45
Oil	2	43	0	0	2	43
Solar	0	0	0	0	0	0
Wind	34	2,985	4	180	30	2,805
Total	83	8,685	8	1,185	75	7,500

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	19	586	1	38	18	548
Intermediate	16	3,256	1	644	15	2,612
Peaker	14	1,858	2	323	12	1,535
Wind Turbine	34	2,985	4	180	30	2,805
Total	83	8,685	8	1,185	75	7,500

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection By Operating Type and Fuel Type

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	14	462	14	462	0	0	0	0	0	0
Coal	1	36	1	36	0	0	0	0	0	0
Hydro	7	1,215	0	0	4	29	3	1,186	0	0
Landfill Gas	1	34	1	34	0	0	0	0	0	0
Natural Gas	9	632	1	9	4	590	4	33	0	0
Natural Gas/Oil	13	3,233	0	0	8	2,637	5	596	0	0
Nuclear Uprates	2	45	2	45	0	0	0	0	0	0
Oil	2	43	0	0	0	0	2	43	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Wind	34	2,985	0	0	0	0	0	0	34	2,985
Total	83	8,685	19	586	16	3,256	14	1,858	34	2,985

Capacity Supply Obligations (CSO) FCA 1

Resource Type	Resource Type	FCA 1	Proration		ARA 2		**Delisted MW Released		Annual Bilateral		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	1,850.074	1,818.402	-31.672	1,817.152	-1.250	1,817.152	0.000	1,515.593	-301.559	1,498.671	-16.922
	Passive Demand	703.488	689.729	-13.759	666.729	-23.000	666.729	0.000	654.078	-12.651	654.078	0.000
Demand Total		2,553.562	2,508.131	-45.431	2,483.881	-24.250	2,483.881	0.000	2,169.671	-314.210	2,152.749	-16.922
Generator Total		30,864.929	29,710.469	-1,154.460	29,814.719	104.250	29,646.719	-168.000	30,406.108	759.389	30,456.525	50.417
Import Total		933.583	898.542	-35.041	818.542	-80.000	818.542	0.000	373.363	-445.179	339.868	-33.495
ISO New England Participation		N/A	N/A	N/A	0.000	N/A	N/A	N/A	N/A	N/A	-242.442	N/A
Grand Total		34,352.074	33,117.142	1,234.932	33,117.142	0.000	32,949.142	-168.000	32,949.142	0.000	32,706.700	0.000

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** Some Capacity that was previously held for reliability was released

Reliability Costs

Net Commitment Period Compensation (NCPC) Operating Costs

What are Daily NCPC Payments?

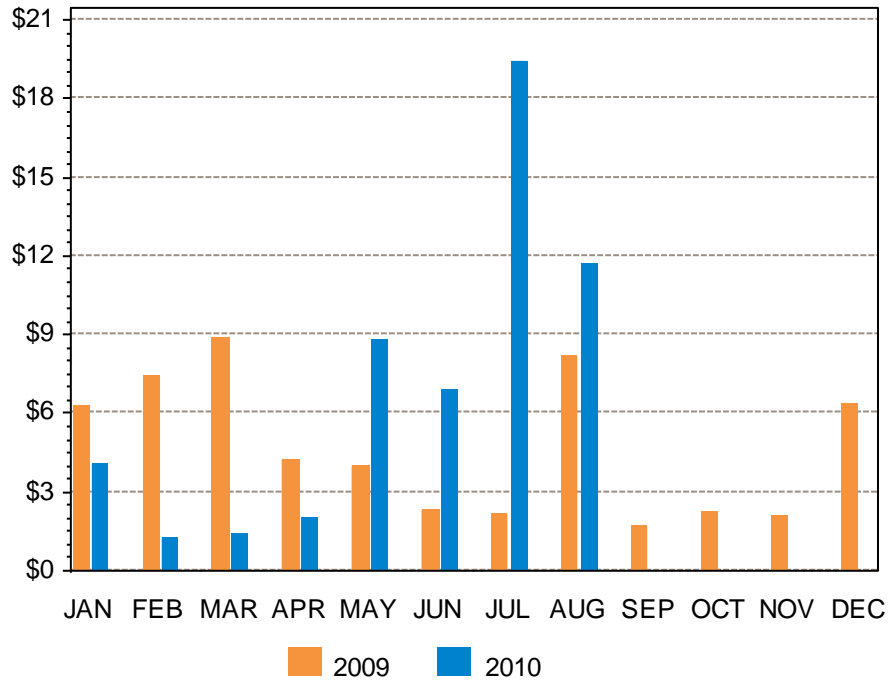
- “Make-whole” payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource’s offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area

Definitions

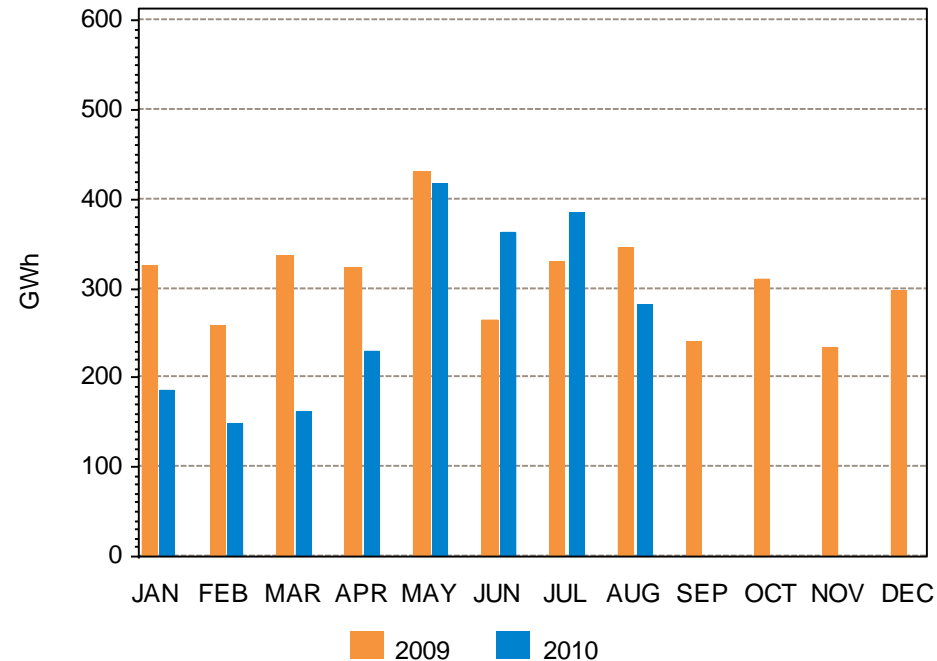
Voltage NCPC Payments	Reliability costs paid to resources operated by the ISO-NE to provide voltage control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are not providing 2 nd Contingency, Voltage, or Distribution requirements. These resources may have been providing first contingency coverage (system-wide or locally)
2nd Contingency NCPC Payments	Reliability costs paid to resources providing adequate capacity in constrained areas to respond to a local second contingency. They are committed based on 2 nd Contingency protocols
Delisted Units	Resources within the control area that have requested to be classified as a non-installed capacity (ICAP) resource, and as such, are not required to offer their capacity into the DA Energy Market

Year-Over-Year Total NCPC Dollars and Energy

Dollars



Energy

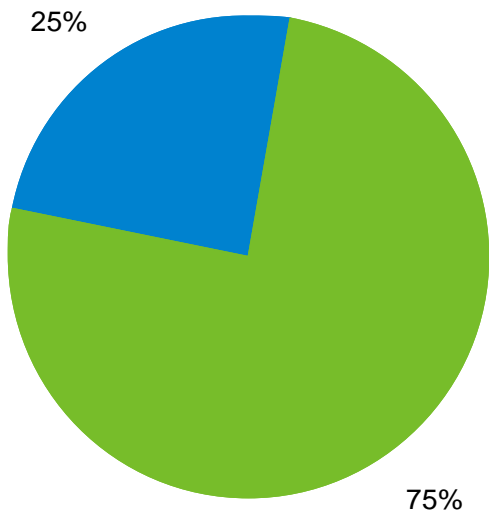


Note:

- Overall Reliability Cost MWh includes out of merit DA and RT 1st Contingency, 2nd Contingency, Voltage, and RT Distribution components.
- Energy includes daily totals of cleared DA energy and RT energy from resources receiving NCPC payments.

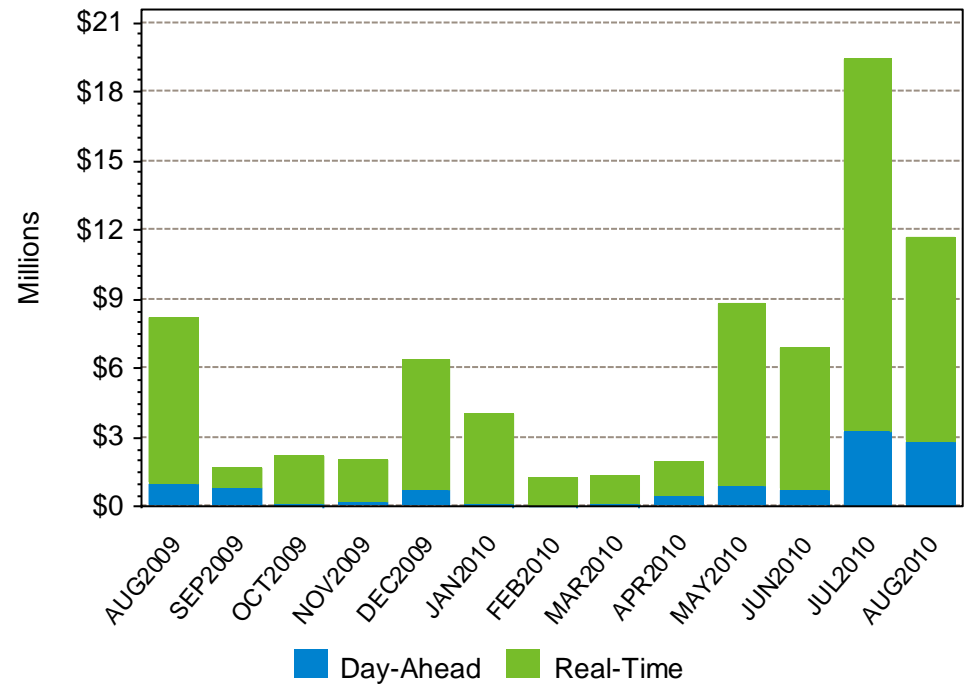
DA and RT NCPC Payments

AUG-10 Total = 11.66 M



■ Day-Ahead ■ Real-Time

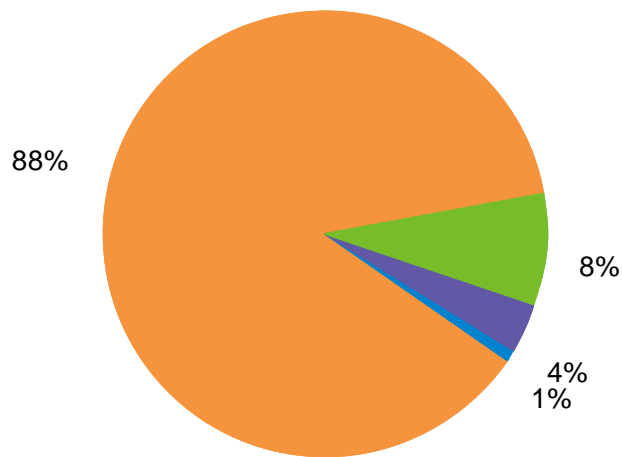
Last 13 Months



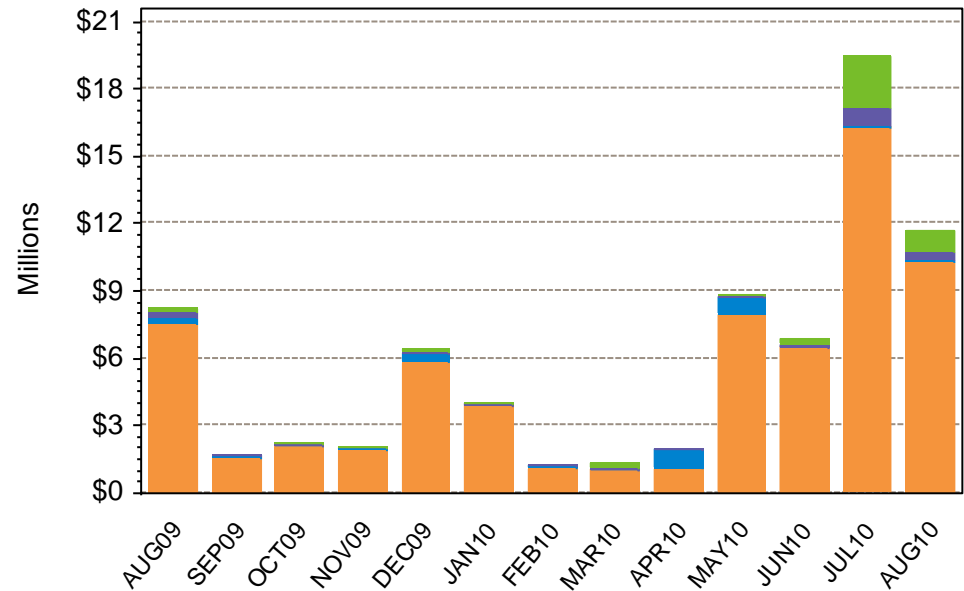
■ Day-Ahead ■ Real-Time

NCPC Payments by Type

AUG-10 Total = 11.66 M



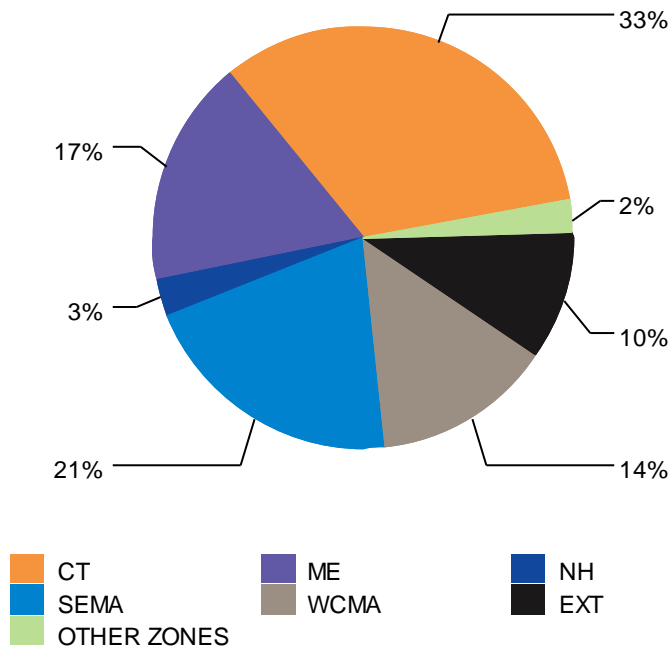
Last 13 Months



1st C – First Contingency
 2nd C – Second Contingency
 Distrib – Distribution
 Voltage – Voltage Support

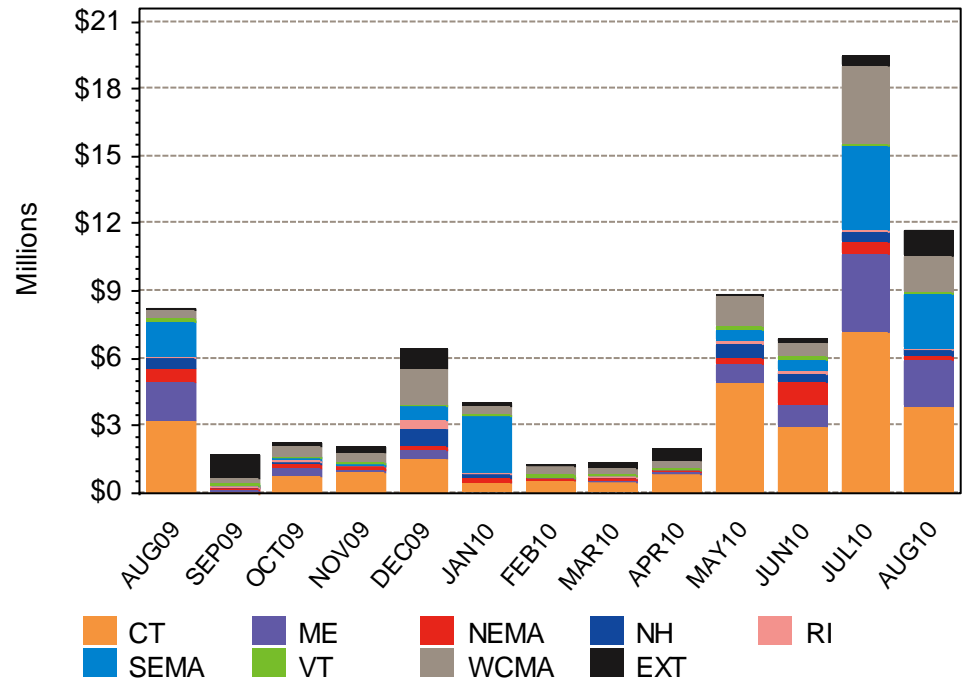
NCPC Payments by Location

AUG-10 Total = 11.66 M



CT – Connecticut Region
 ME – Maine Region
 NH – New Hampshire Region
 RI – Rhode Island Region

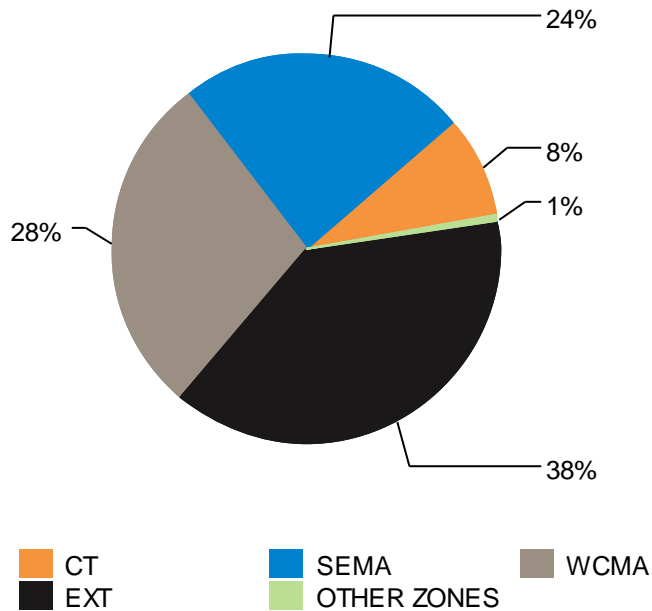
Last 13 Months



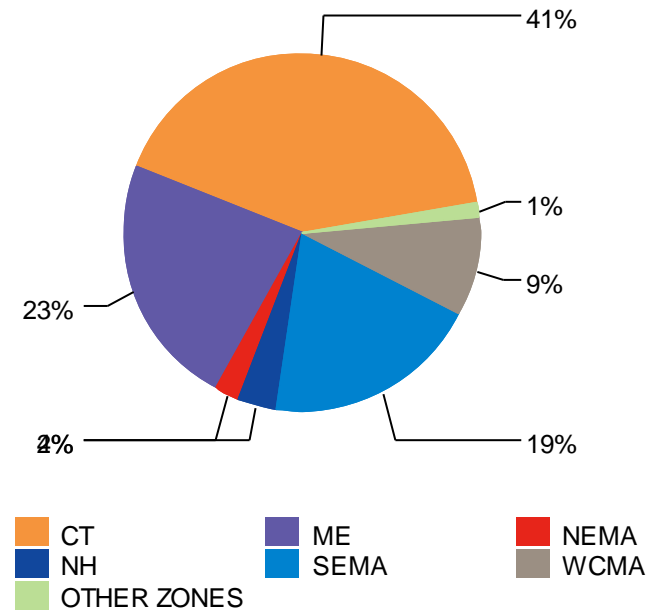
VT – Vermont Region
 SEMA – Southeast Massachusetts Region
 WCMA – Western/Central Massachusetts Region
 NEMA – Northeast Massachusetts Region
 EXT – External Locations

DA and RT NCPC Payments by Location

AUG-10 Day-Ahead Total = \$2.86 M

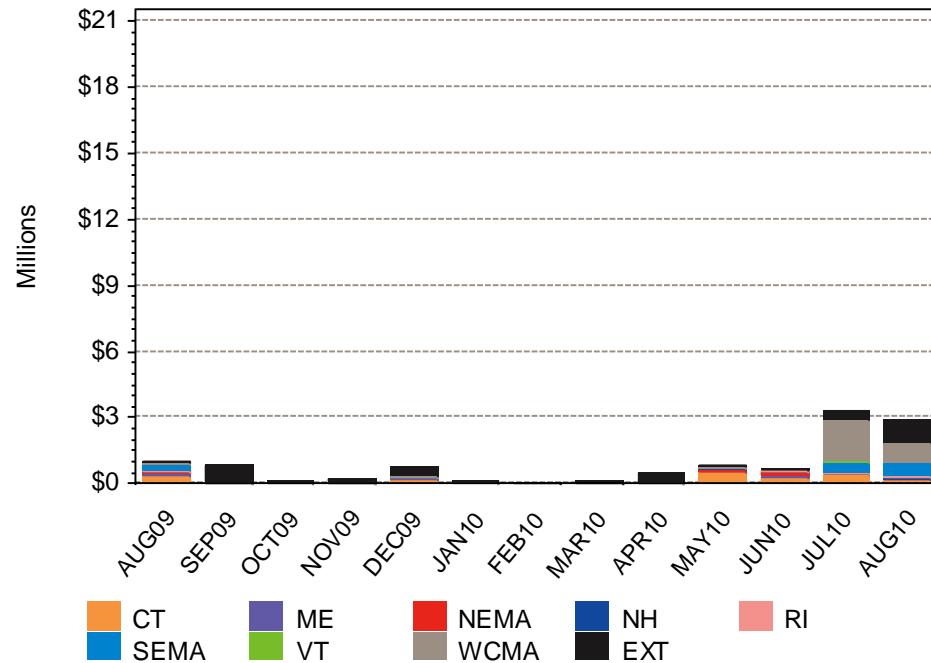


AUG-10 Real-Time Total = \$8.80 M

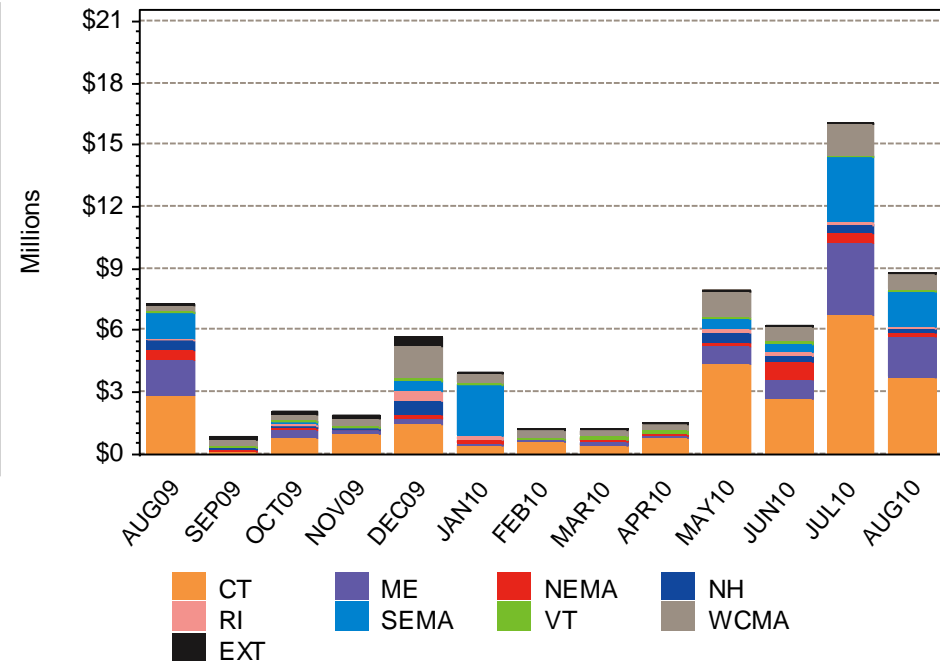


DA and RT NCPC Payments by Location, Last 13 Months

Day-Ahead, Last 13 Months

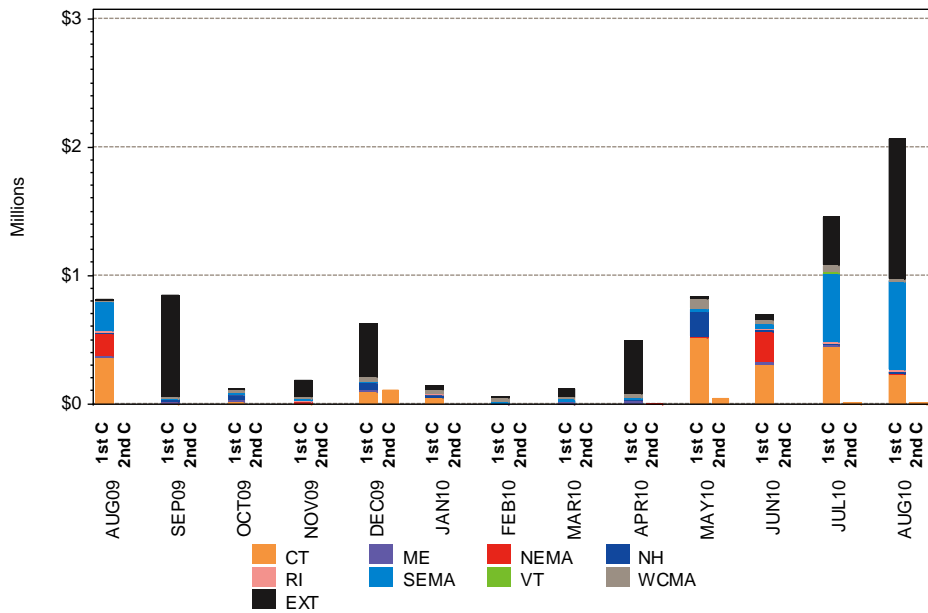


Real-Time, Last 13 Months

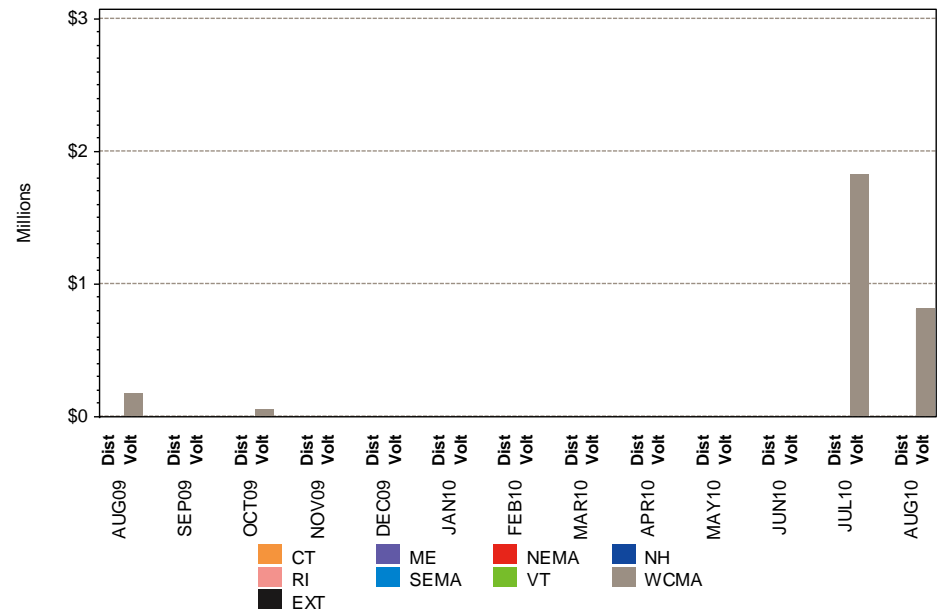


DA NCPC Payments by Type and Location

First and Second Contingency Payments

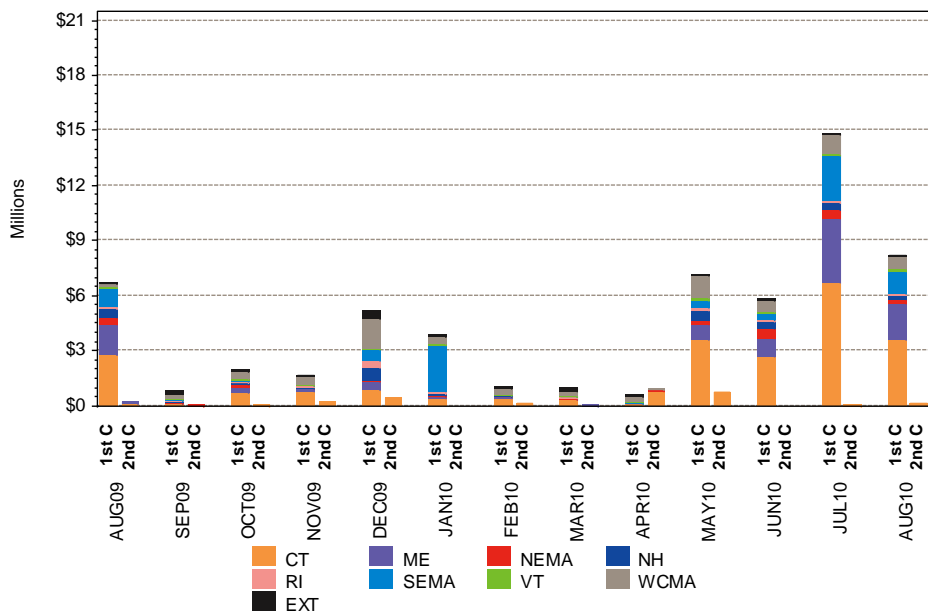


Voltage and Distribution Payments

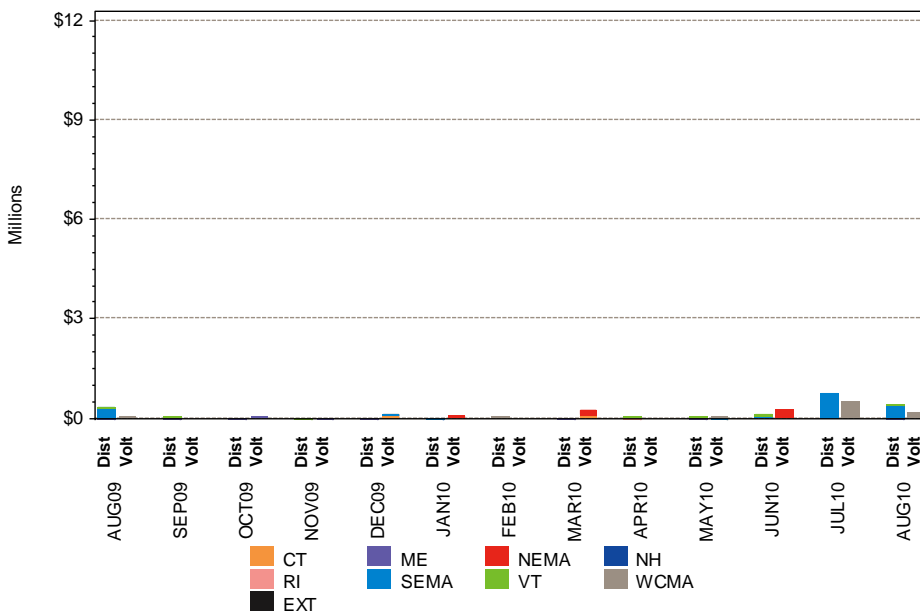


RT NCPC Payments by Type and Location

First and Second Contingency Payments

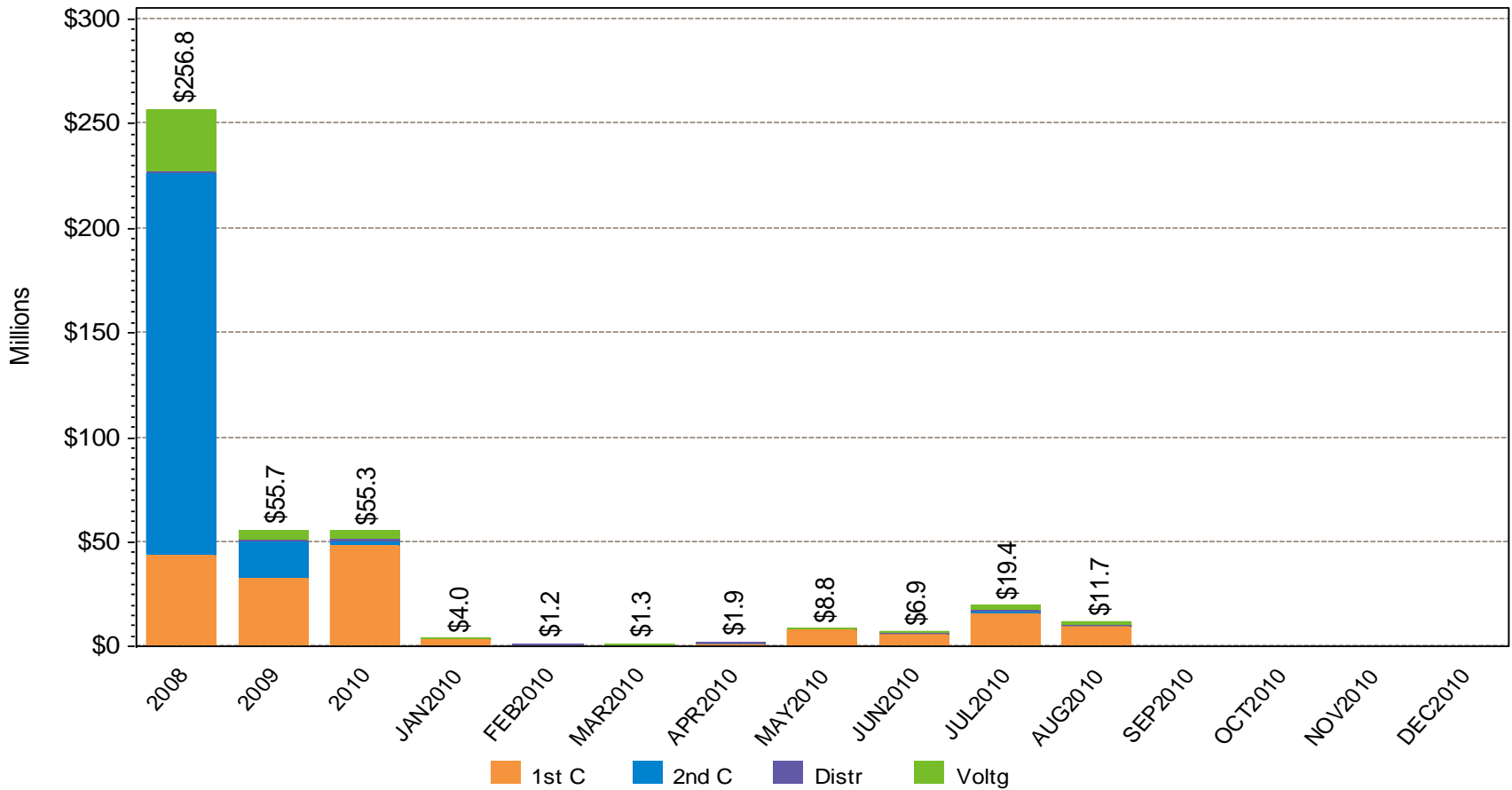


Voltage and Distribution Payments



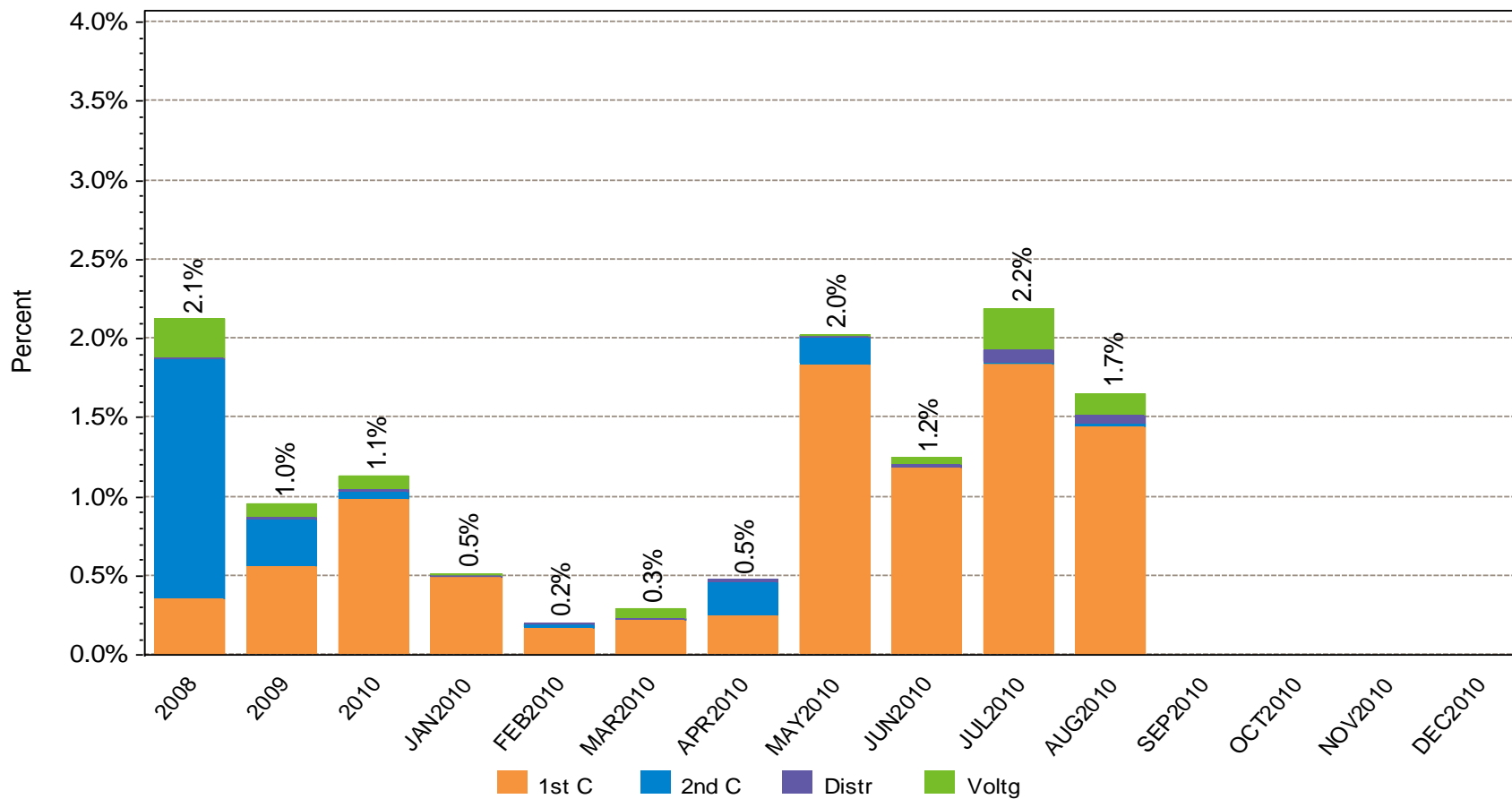
NCPC Payments by Type

Payments by Type of NCPC



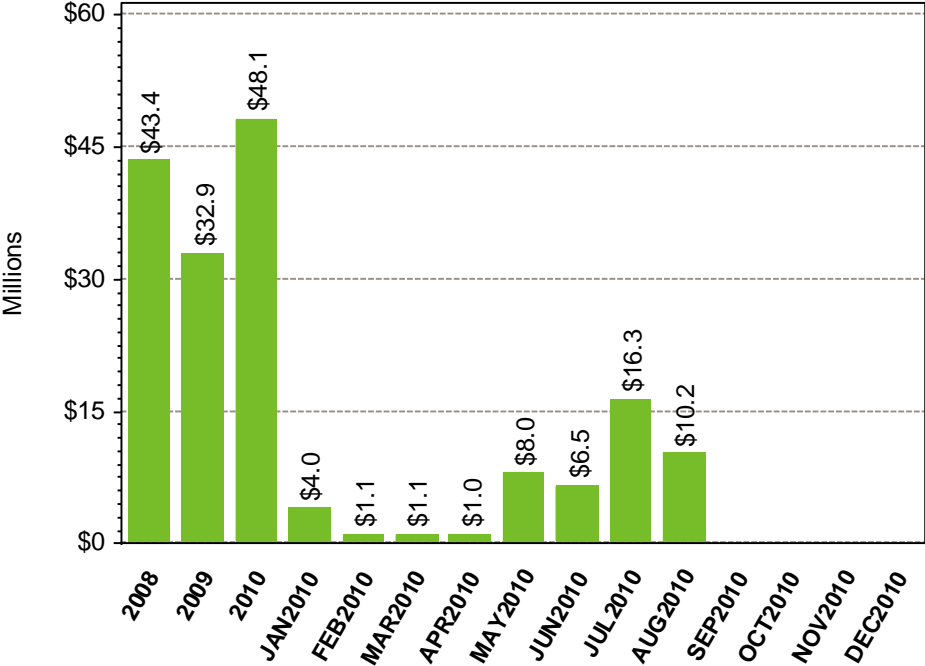
NCPC Payments by Percent of Energy Market

NCPC By Type as Percent of Energy Market

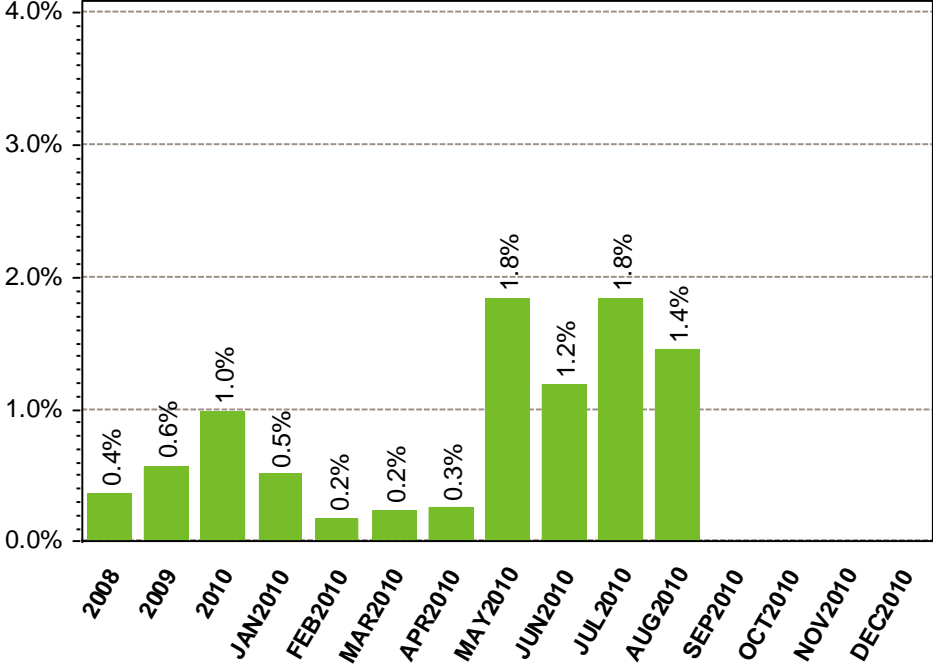


First Contingency NCPC Payments

Value of Payments



% of Energy Market Value

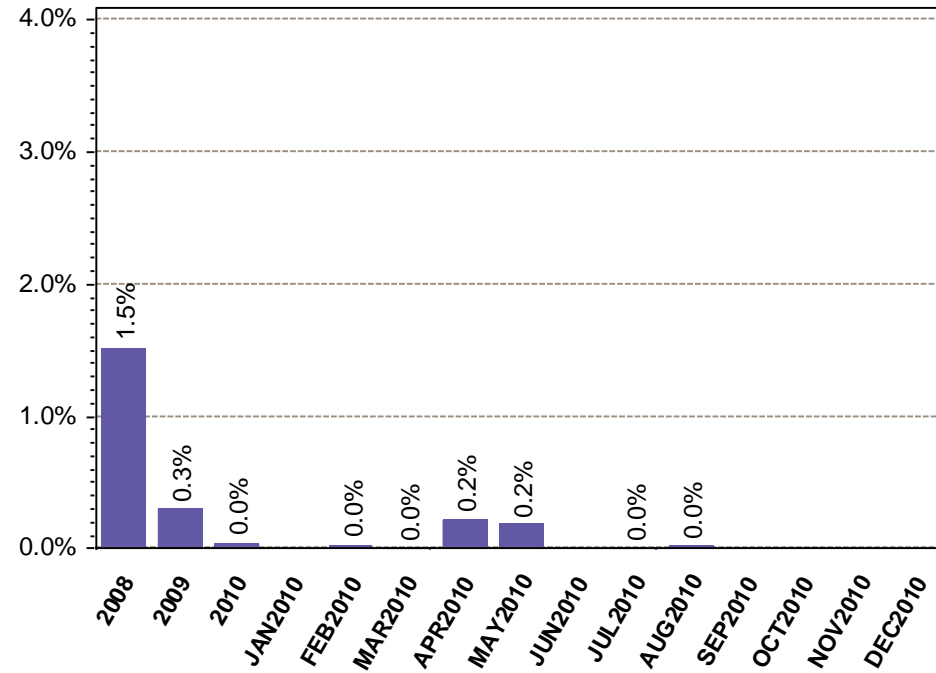
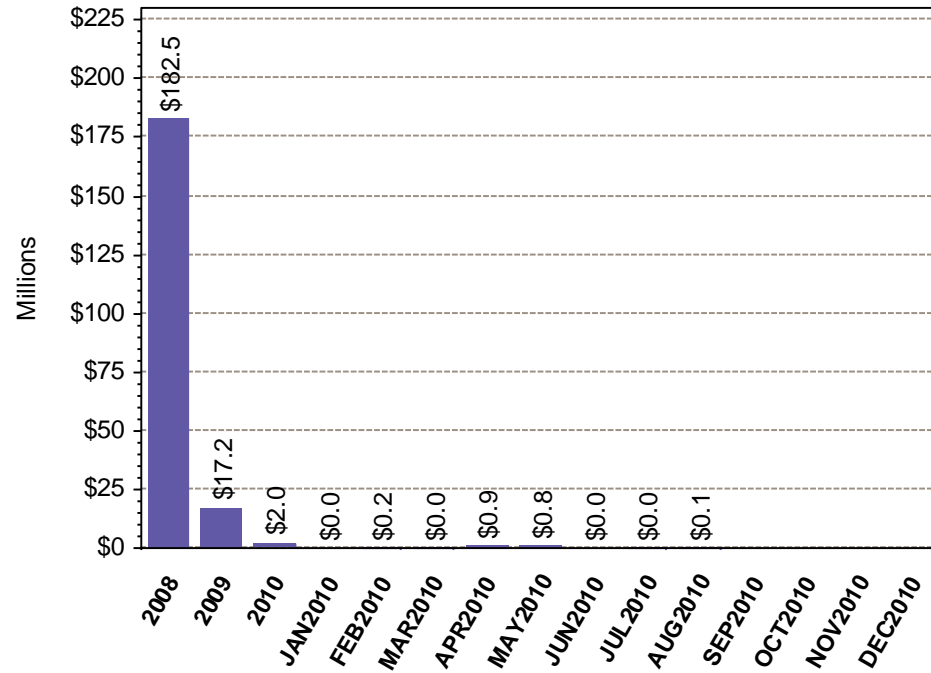


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Second Contingency NCPC Payments

Value of Payments

% of Energy Market Value

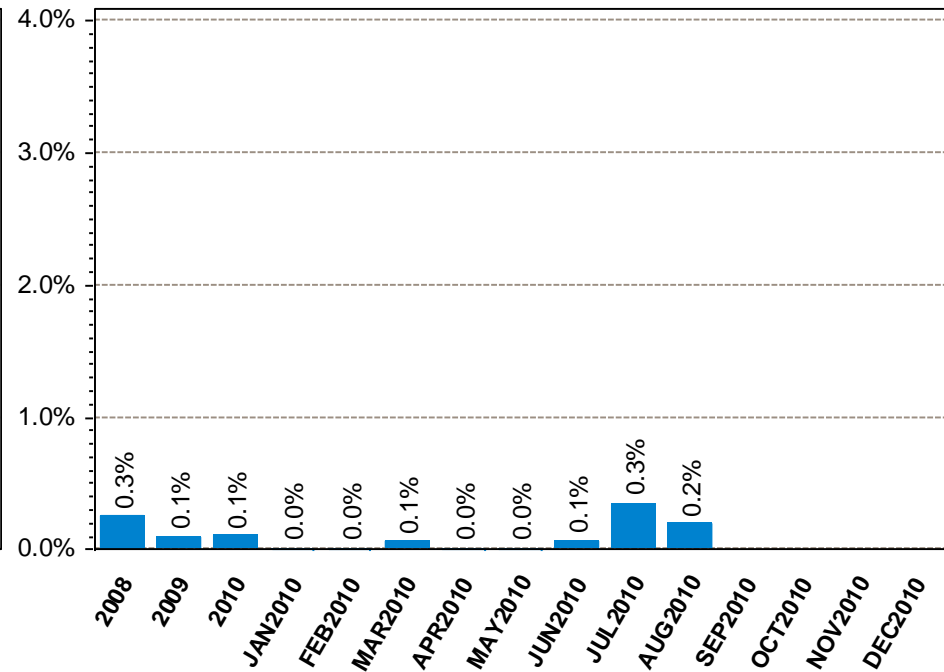
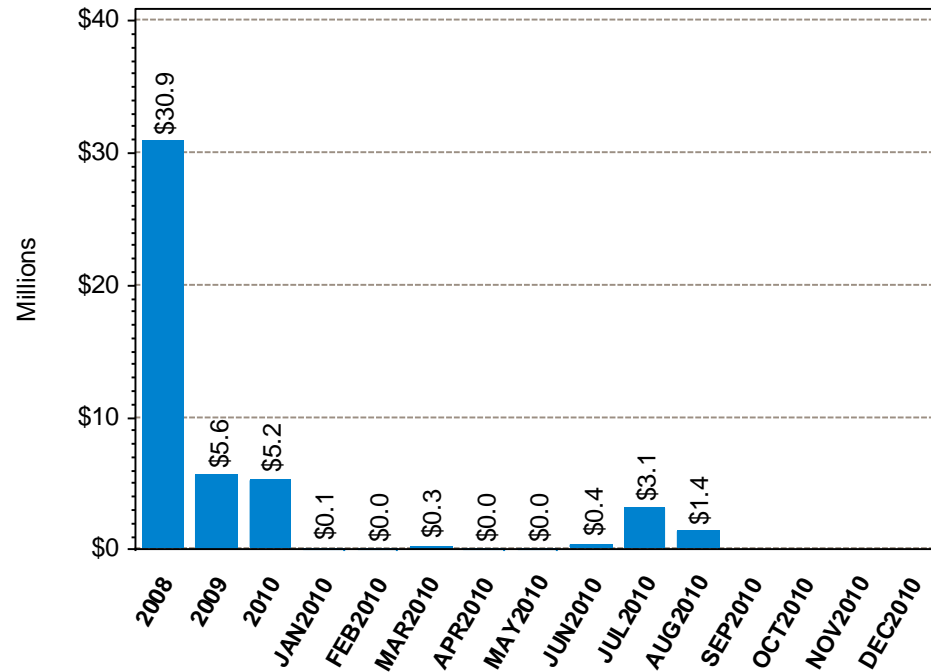


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Payments

Value of Payments

% of Energy Market Value



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

DA vs. RT Pricing

The following slides outline

- This month vs. prior year's average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total inc's and dec's
- Self-schedules
- DA vs. RT net interchange
- Delisted capacity

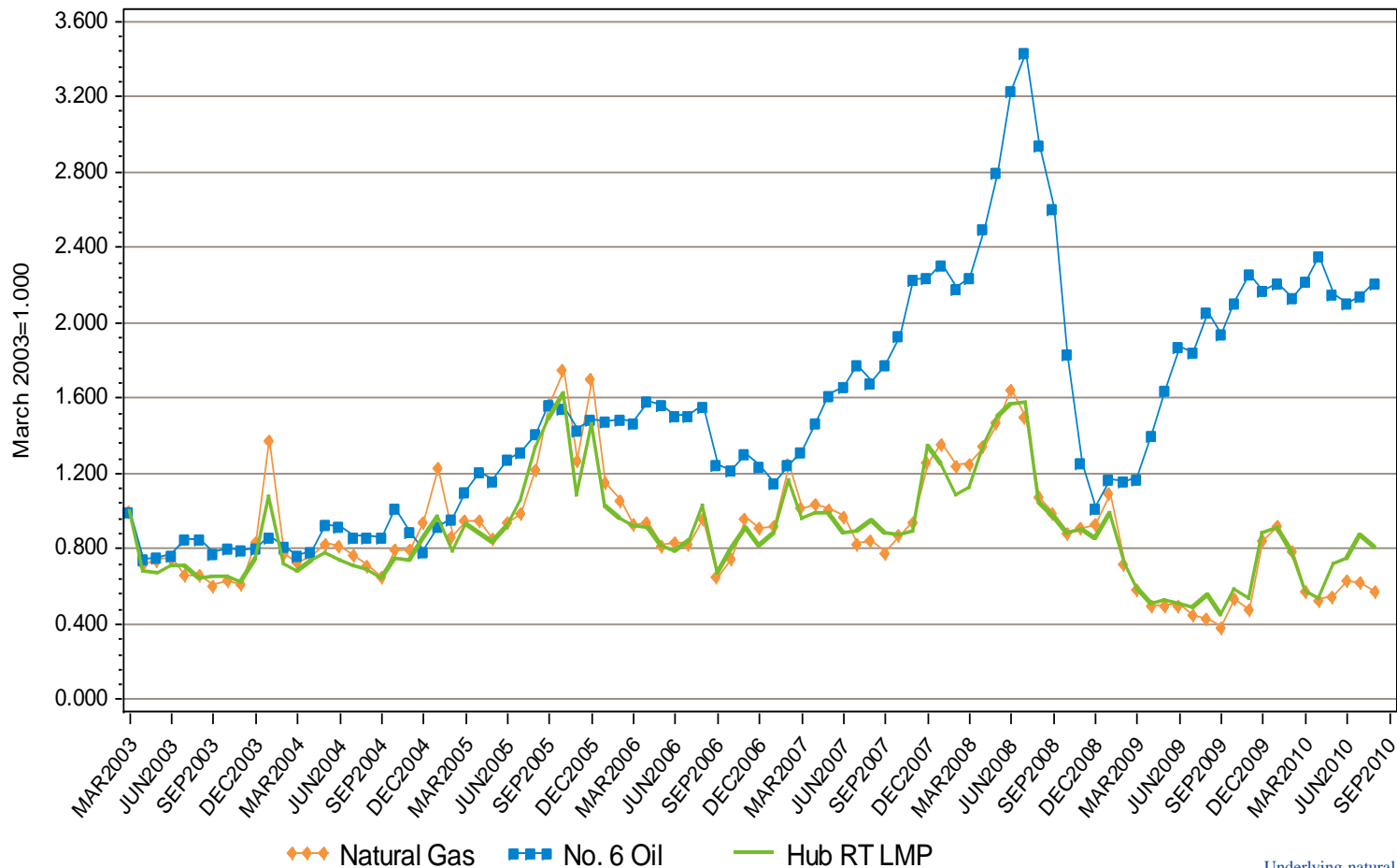
DA vs. RT LMPs (\$/MWh)

Arithmetic Average

Year 2008	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$79.85	\$84.85	\$76.13	\$79.22	\$81.07	\$79.33	\$82.73	\$81.31	\$80.64
Real-Time	\$80.49	\$83.56	\$75.60	\$79.52	\$81.17	\$79.62	\$81.56	\$81.41	\$80.75
RT Delta %	0.8%	-1.5%	-0.7%	0.4%	0.1%	0.4%	-1.4%	0.1%	0.1%
Year 2009	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$41.44	\$42.73	\$39.60	\$40.85	\$41.57	\$41.13	\$41.70	\$41.89	\$41.52
Real-Time	\$41.78	\$42.89	\$39.97	\$41.32	\$42.06	\$41.57	\$42.03	\$42.33	\$42.00
RT Delta %	0.8%	0.4%	1.0%	1.1%	1.2%	1.1%	0.8%	1.1%	1.1%

August-09	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$35.02	\$36.58	\$33.49	\$34.86	\$35.58	\$34.89	\$35.26	\$35.48	\$35.23
Real-Time	\$38.12	\$39.23	\$36.11	\$37.97	\$38.78	\$37.78	\$38.25	\$38.53	\$38.25
RT Delta %	8.8%	7.2%	7.8%	8.9%	9.0%	8.3%	8.5%	8.6%	8.6%
August-10	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$52.77	\$57.46	\$51.51	\$52.94	\$55.05	\$52.47	\$52.69	\$54.63	\$53.55
Real-Time	\$54.85	\$56.55	\$53.20	\$54.75	\$56.15	\$54.37	\$54.96	\$56.10	\$55.40
RT Delta %	4.0%	-1.6%	3.3%	3.4%	2.0%	3.6%	4.3%	2.7%	3.5%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	50.7%	57.1%	53.8%	51.9%	54.7%	50.4%	49.4%	53.9%	52.0%
Yr over Yr RT	43.9%	44.2%	47.3%	44.2%	44.8%	43.9%	43.7%	45.6%	44.8%

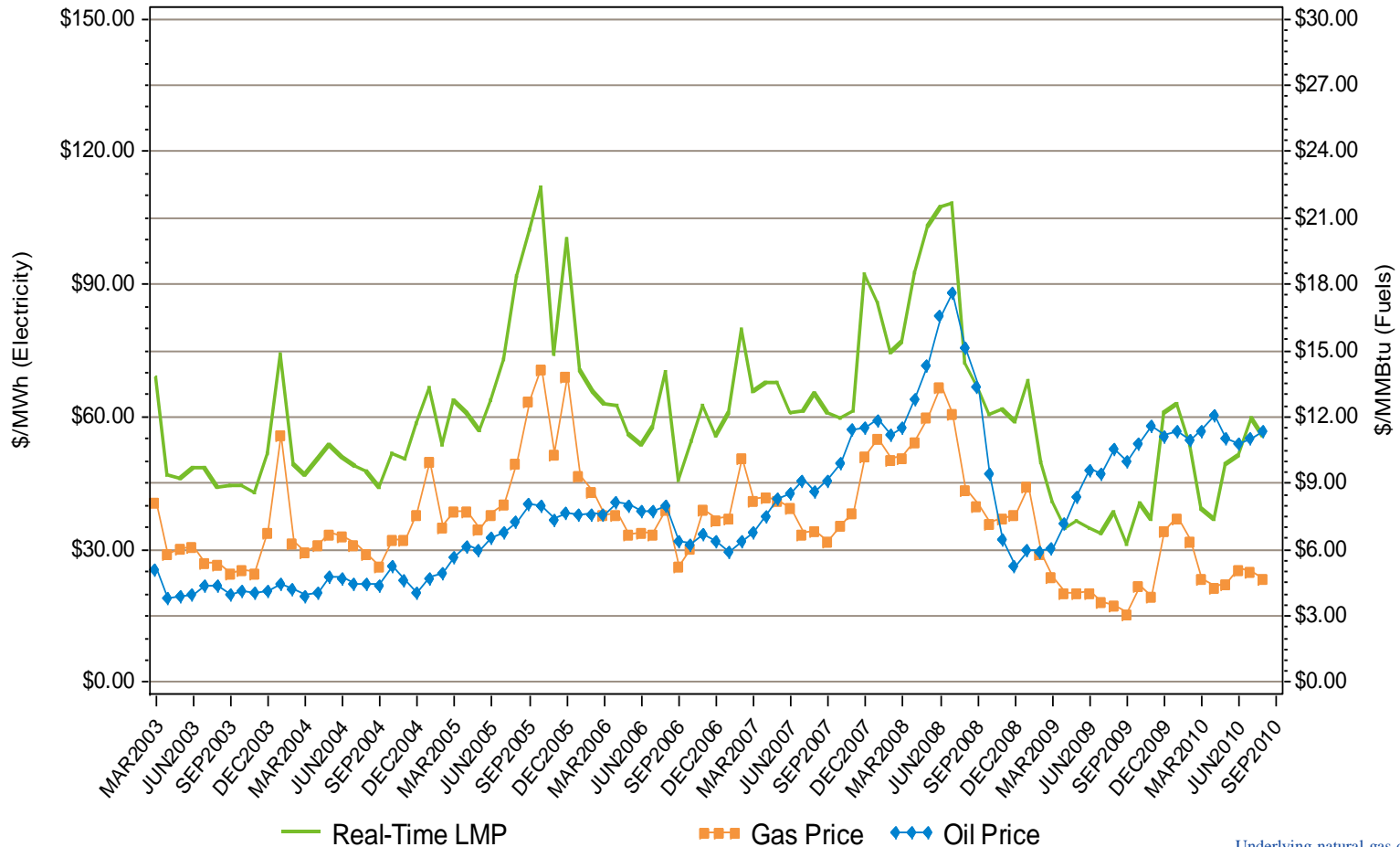
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:



Monthly Average Fuel Price and RT Hub LMP



Underlying natural gas data furnished by:



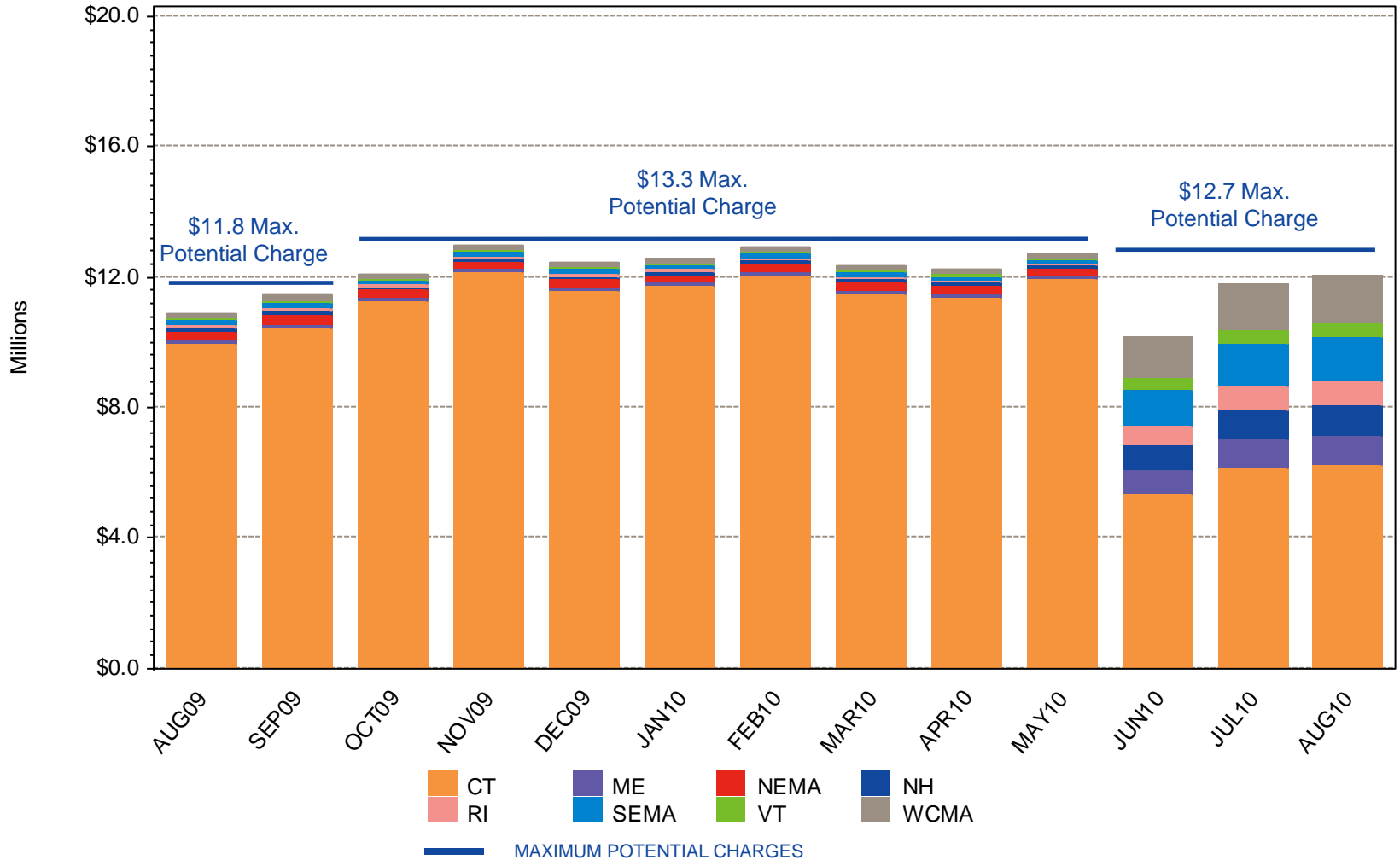
Reserve Market Results – August 2010

- Maximum potential Forward Reserve Market payments of \$12.7M were reduced by credit reductions of \$253K, failure-to-reserve penalties of \$380K and failure-to-activate penalties of \$2K, resulting in a net payout of \$12.0M or 95% of maximum
 - Rest of System: \$1.09M/\$1.16M (94%)
 - Southwest Connecticut: \$3.52M/\$3.78M (93%)
 - Connecticut: \$7.43M/\$7.73M (96%)
 - NEMA: n/a
- \$1.4M total Real-Time credits were reduced by \$443K in Forward Reserve Energy Obligation Charges for a net of \$964K in Real-Time Reserve payments
 - Rest of System: 80 hours, \$636K
 - Southwest Connecticut: 80 hours, \$208K
 - Connecticut: 80 hours, \$66K
 - NEMA: 80 hours, \$55K
- The system reserve bias factor was used on three days (August 2, 30, and 31) during this period

* “Failure to reserve” results in both reductions in credits and penalties in the Locational Forward Reserve Market.

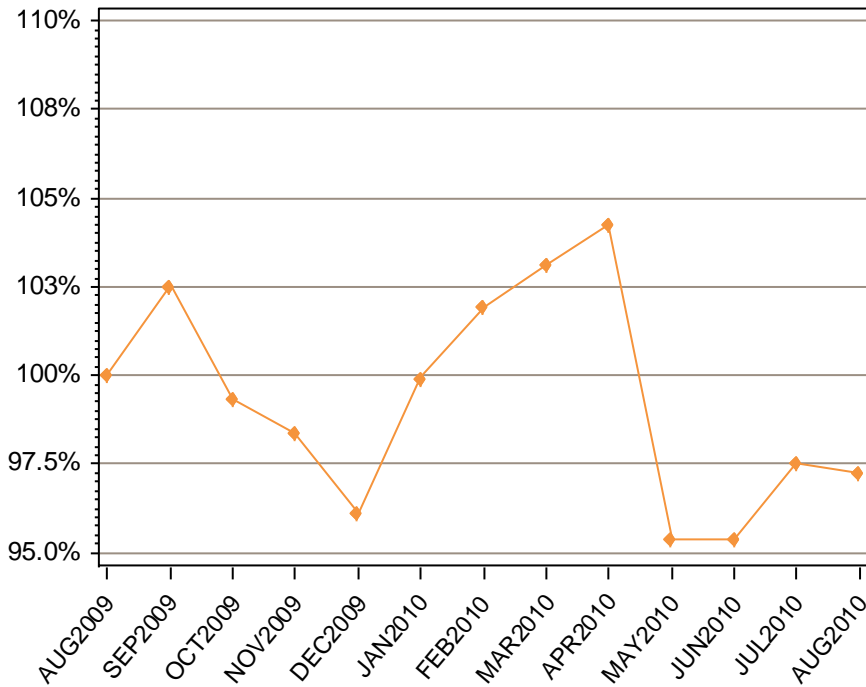
LFRM Charges to Load by Load Zone (\$)

LFRM Charges by Zone, Last 13 Months

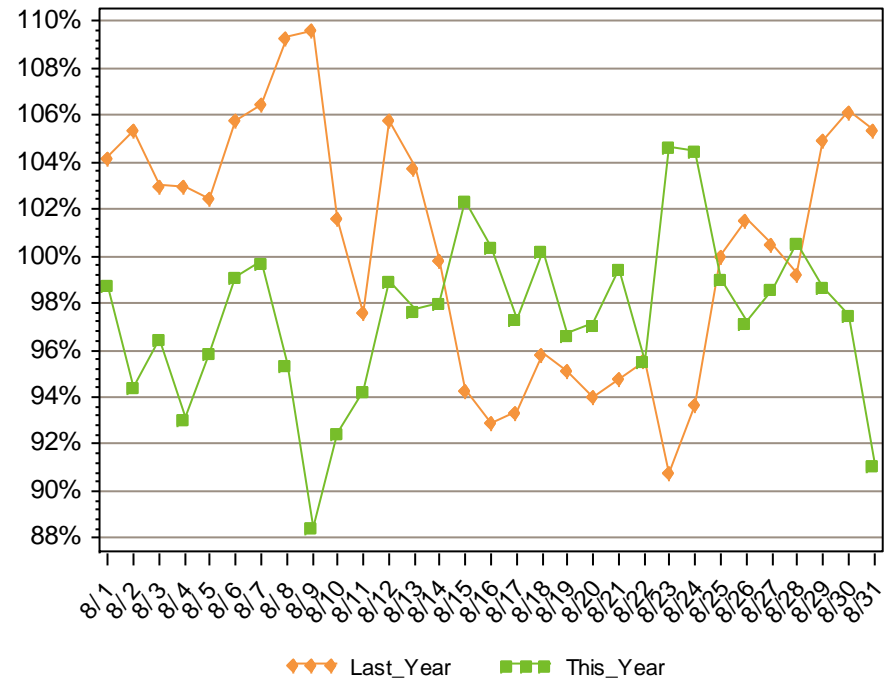


DA Load Obligation Percent of RT Load Obligation

Monthly, Last 13 Months

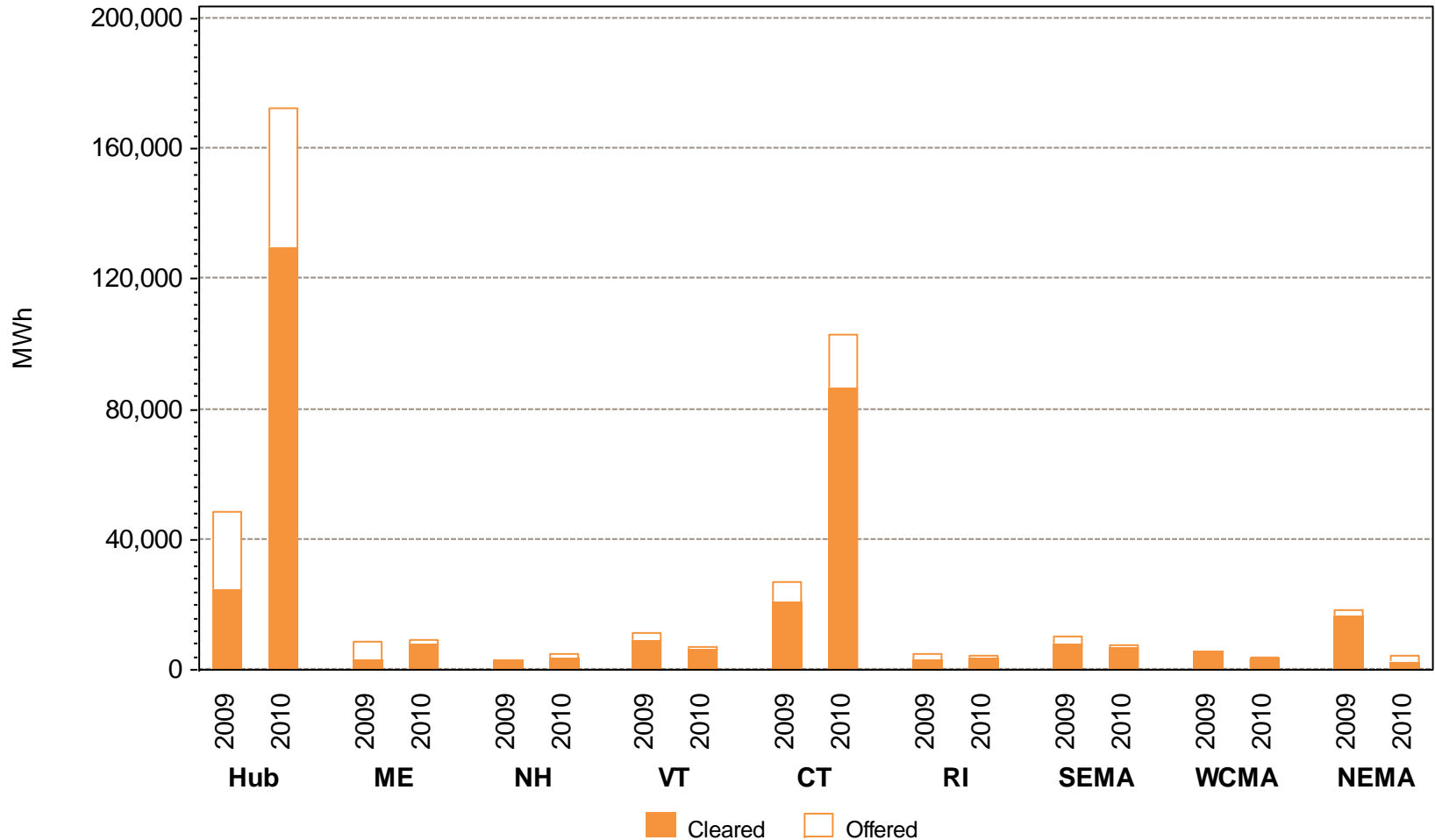


Daily, This Year vs. Last Year



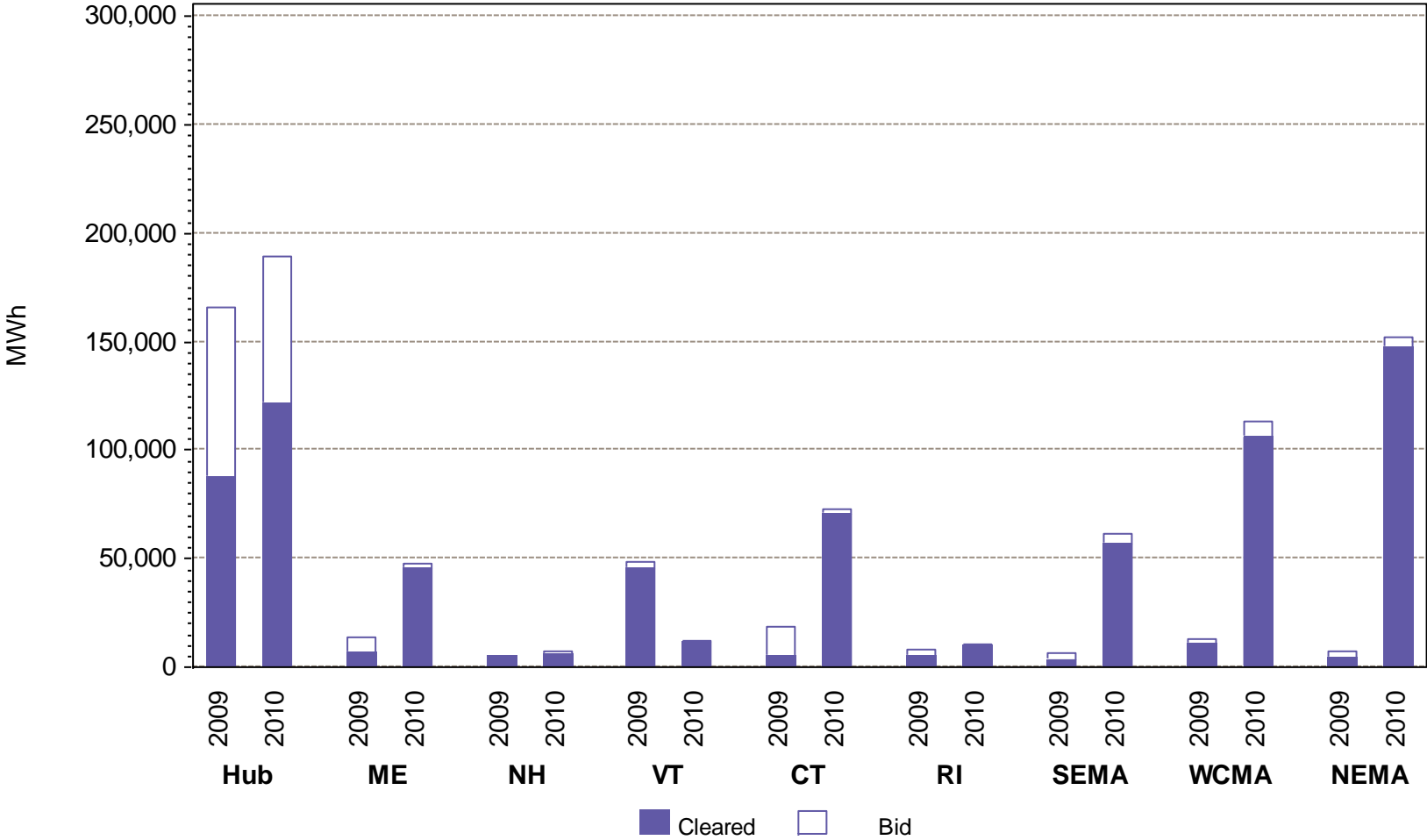
Zonal Increment Offers and Cleared Amounts

August Monthly Totals by Zone



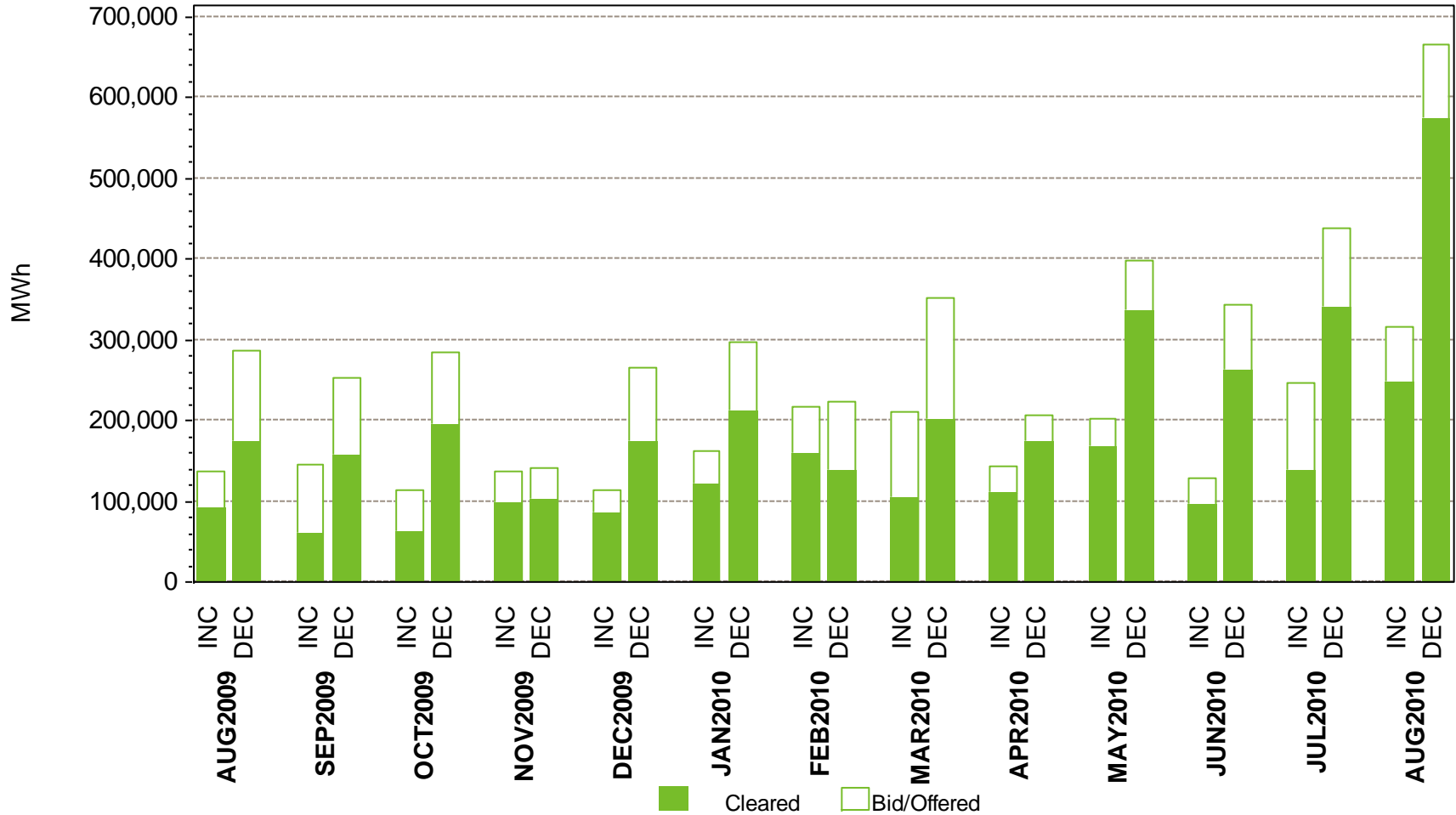
Zonal Decrement Bids and Cleared Amounts

August Monthly Totals by Zone



Total Increment Offers and Decrement Bids

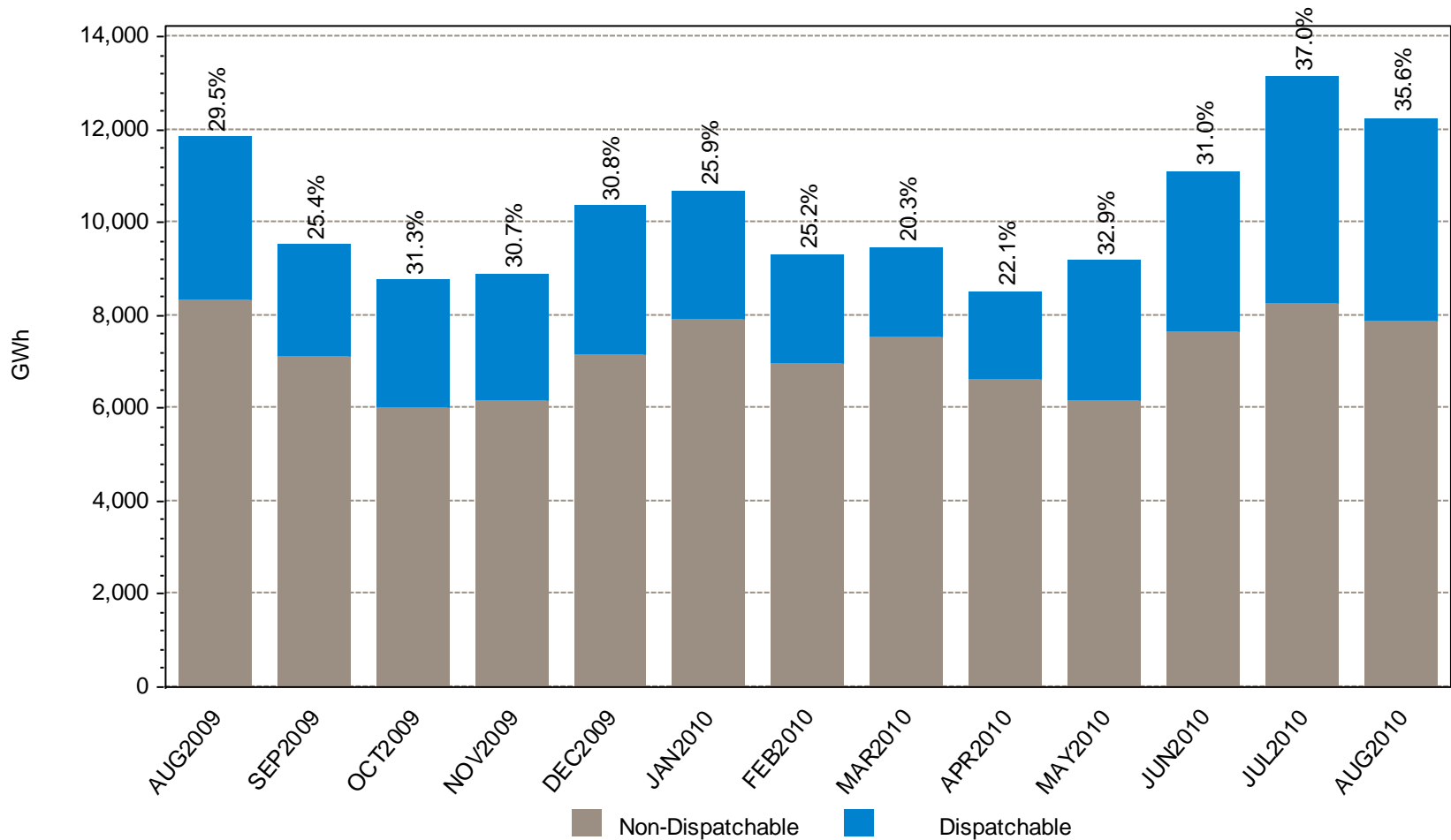
Zonal Level, Last 13 Months



Data excludes nodal offers and bids

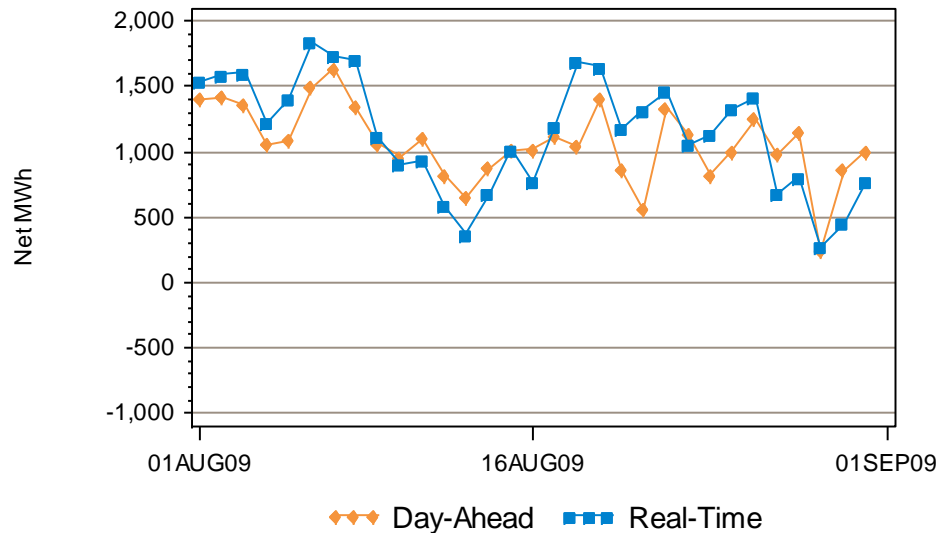
Dispatchable vs. Non-Dispatchable Generation

Total Monthly Energy; Dispatchable % Shown

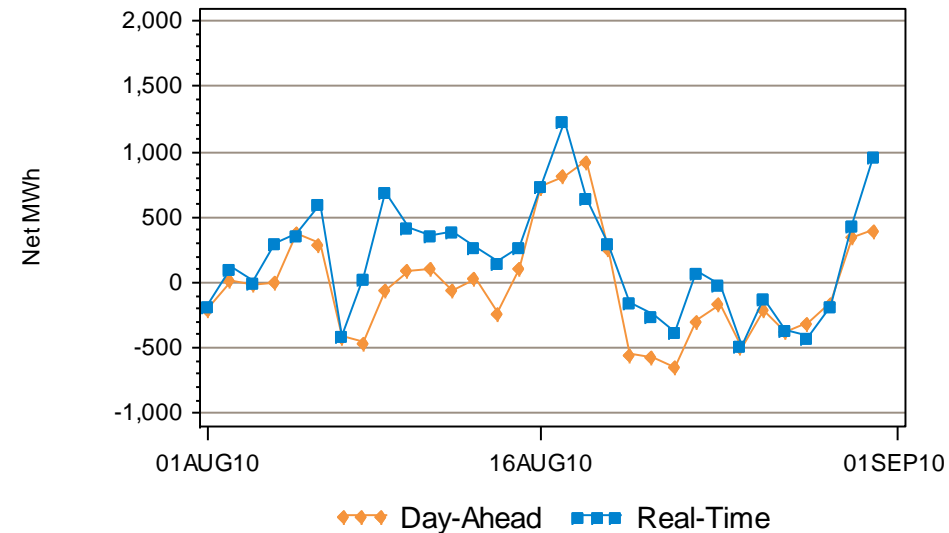


DA vs. RT Net Interchange August 2010 vs. August 2009

Hourly Average by Day, Last Year



Hourly Average by Day, This Year



Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports

Regional System Plan (RSP)

RSP10 Report Schedule and Process

- August 12 – Written substantive comments on the draft RSP10 were discussed with the Planning Advisory Committee (PAC) and will be reflected in the Public Meeting version
 - All final comments are subject to review by ISO staff, including the Technical Editor
 - Status of the NEEWS project
 - Additional emphasis on the region’s ability to meet its Renewable Portfolio Standard goals
 - Clarifying comments, primarily on environmental issues, wind and solar unit integration issues, and transmission projects
 - Update the new initiatives included in Section 12.3.2 and include them in the Executive Summary
- The Public Meeting Version of RSP10 will be posted September 8
 - Please submit questions **by noon on September 14**
 - Communicate to ISO through pacmatters@iso-ne.com

RSP10 Public Meeting: September 16

Preliminary Agenda

9:30 a.m. – 9:40 a.m.	Welcome
9:40 a.m. – 10:30 a.m.	Presentation of the 2010 RSP and stakeholder discussion (priority will be given to written questions received in advance of the public meeting)
10:30 a.m. – 10:45 a.m.	Break
10:45 a.m. – 12:00 p.m.	Panel #1: State Planning Initiatives and Non-Transmission Alternatives
12:15 p.m. – 1:00 p.m.	Lunch
1:15 p.m. – 1:45 p.m.	Keynote Address: Patricia A. Hoffman, Assistant Secretary for Electricity Delivery and Energy Reliability, U.S. Department of Energy
1:45 p.m. – 3:15 p.m.	Panel #2: Drivers of the Future Grid
3:15 p.m. – 3:30 p.m.	Concluding Comments

PAC Meeting Schedule and Tentative Agendas

- **September 21** – Update on interregional production cost studies, Maine Power Reliability Program, Northern Maine System Performance, SWCT Needs, UI PTF improvements, and Transmission Owner PAC meetings to present Local System Plans for UI, NU, VT, and NGRID
- **October 21** – Tentative agenda includes the RSP Project List, transmission studies, and an introduction to non-transmission analysis planned for RSP11
- **November 16** – Wind day and discussion of state Energy Efficiency programs

Interregional Planning and Coordination

- Inter-Area Planning Stakeholder Advisory Committee WebEx is tentatively scheduled for October 6 to discuss interregional production cost studies
- Comments on the FERC system planning NOPR are due by September 29
- Environmental Advisory Group meetings are planned for October 8 and December 17

Eastern Interconnection Planning Collaborative (EIPC)

- Stakeholder Steering Committee has formed working groups to support their efforts
 - Roll-up Working Group
 - Modeling Working Group
 - Scenario Planning Working Group
 - Governance Task Force
- Several New England representatives have volunteered for the working groups
- Initial efforts are to establish ground rules and confirm objectives
- EIPC representative will attend each working group meeting
- Information on the working groups, including high-level meeting notes, will be posted at www.eipconline.com

RSP Project Stage Descriptions

Stage	Description
1	Planning and Preparation of Project Configuration
2	Pre-construction (e.g., material ordering, project scheduling)
3	Construction in Progress
4	In Service

North Shore Upgrades – Merrimack Valley

Status as of 9/7/10

Project Benefit: Maintains system reliability for the North Shore area independent of Salem Harbor generation

Upgrade	Expected In-service	Present Stage
Wakefield Junction/Merrimack Valley		
115 kV Overhead Reconductor (G133E)	Feb-08	4
Reconductor Wakefield Junction - Golden Hills Tap 115 kV	Sep-08	4
30 MVAR 115 kV Capacitor at Revere	Oct-08	4
Wakefield Junction Substation	Nov-09	4
Loop 345 kV and 115 kV lines into Wakefield Substation	Nov-09	4
Retirement of Golden Hills Substation	Apr-10	4
Add parallel 115 kV cable in Mystic-Everett line	Oct-10	2
Add King Street - W. Amesbury 115 kV line	Mar-11	2
Sandy Pond 345 kV Breakers	Jun-12	2
Reconductor Overhead portion of Mystic-Everett 115 kV line	Jun-12	2
Replace Salem-Railyard Cables	Oct-13	2

- Received Reliability Committee (RC) recommendation for I.3.9 approval on 3/27/08
- Final costs presented at 11/19/08 PAC meeting and at 12/18/08 RC meeting (for future vote)
- Transmission Cost Allocation (TCA) application presented at special stakeholder meeting on 1/29/09
- TCA recommended for approval by RC at March 2009 meeting

Lower Southeastern Massachusetts (SEMA) Proposed Long-term Upgrades

Status as of 9/7/10

Project Benefit: Improves system reliability for the Lower SEMA area independent of area generation

Upgrade	Expected In-service	Present Stage
Expand the Carver substation	Dec-12	1
Build new 345 kV line from Carver to new Service Road substation near intersection with the #115 line	Dec-12	1
New Service Road substation with 345-115 kV autotransformer and 3-breaker 115 kV ring bus	Dec-12	1
Build new 115 kV line from Canal to Barnstable	Dec-12	1
Upgrade the D21 line from Bell Rock to High Hill	Dec-12	1
342/322 DCT Separation	Dec-12	1

- ISO I.3.9 approval on 11/5/09
- Siting application scheduled to be filed late summer 2010
- Full status update (needs, preferred solution, needs reassessment) given at 4/27/10 PAC
- Draft solutions report posted 6/21/10; final needs report posted 6/21/10

Maine Power Reliability Program (MPRP)

Status as of 9/7/10

Project Benefit: Addresses long-term system needs of Bangor Hydro Electric and Central Maine Power, thermal and voltage issues in western Maine and supports load growth in southern Maine

Upgrade	Expected In-service	Present Stage
New 345 kV Line Construction (Orrington-Albion Road, Albion Road-Coopers Mills, Coopers Mills-Larrabee Road, Larrabee Road-Surowiec), (Surowiec-Raven Farm, South Gorham-Maguire Road, Maguire Road-Three Rivers)	2012	1
New 115 kV Line Construction (Orrington-Coopers Mills, Coopers Mills-Highland, Larrabee Road-Middle Street, Middle Street-Lewiston Lower, Larrabee Road-Livermore Falls, Livermore Falls-Rumford IP, Raven Farm-East Deering, East Deering-Cape, alter Section 212 to become Larrabee Road-Monmouth Substation and Monmouth Substation-Bowman Street, alter Section 86 to become Bucksport-Belfast and Belfast-Lincolntonville)	2012	1
Modify Spring Street substation to create a ring bus. Remove Browns Crossing substation. Reterminate lines at Maine Yankee substation. Loop Section 375 Buxton-Maine Yankee into Surowiec. Transfer existing 115 kV lines from Gulf Island to Larrabee Road substation.	2012	1
New 115 kV Capacitors (10 MVAR at Epping, 10 MVAR at Trenton). New 34.5 kV Capacitor (10.8 MVAR at Belfast)	2012	1
Separation of Double Circuit Towers (345 Kennebec River Crossing 375/377, 345 kV Maine Yankee 375/392, 115 kV Bucksport 65/205)	2012	1

- ISO I.3.9 approval on 7/31/08. ISO I.3.9 approval on 2/26/09 for project revisions
- TCA application presented at special stakeholder meeting on 1/29/09. RC vote on 5/19/09 to recommend approval failed with 64.36% in favor
- TCA determination letter sent on 1/29/10
- Maine PUC issued an order approving most of the projection on 6/10/10

Vermont Southern Loop Project

Status as of 9/7/10

Project Benefit: Improves Vermont and New England reliability by addressing the regional issues regarding the loss of the Coolidge – Vermont Yankee (340) 345 kV line

Upgrade	Expected In-service	Present Stage
Vermont Yankee – Newfane – Coolidge 345 kV line	Dec-10	3
Vernon 345/115 kV substation	Dec-10	3
Newfane 345/115 kV substation	Dec-10	3
Loop new 345 kV line into Newfane	Dec-10	3
Coolidge 345 kV substation expansion	Dec-10	3

- ISO I.3.9 approval on 10/1/08
- RC voted to recommend TCA approval to the ISO on 2/24/09
- Construction ahead of original schedule

New England East-West Solution (NEEWS)

Status as of 9/7/10

Plan Benefit: Improve New England reliability by increasing transfer limits of three critical interfaces and by eliminating future Springfield, MA and Rhode Island criteria violations

Sample Upgrade	Expected In-service	Present Stage
Interstate Reliability Project (IRP)	2013	1
Greater Springfield Reliability Project (GSRP)	2013	1
Central Connecticut East-West Reliability Project (CCRP)	2013	1
Rhode Island Reliability Project (RIRP)	2012	1

- Final “Needs” report posted (both redacted and secured versions)
- Final “Options” report posted (both redacted and secured versions)
- NEEWS preferred alternatives presented at 5/19/08 PAC meeting
- Received ISO I.3.9 approval 9/22/08
- Reaffirmed need for RIRP and GSRP at 6/17/09 PAC meeting
- IRP discussion held at 8/12/10 PAC meeting. ISO findings show continued need for IRP
- Need for CCRP under study

Transmission Siting Update

- New England East-West Solution
 - ISO involvement in RI siting for RIRP complete
 - RI PUC issued draft approval
 - Siting application filed with MA and CT for Springfield portion in October 2008
 - Springfield – CT
 - CT Siting Council approved entire project with the Manchester – Meekville Junction Variation (separate the 395 3-terminal line into 2 separate lines)
 - Springfield – MA
 - Preliminary bench decision supports need but some routing/EMF issues remain

Transmission Siting Update, *cont.*

- Vermont Southern Loop Project
 - Project filed with Vermont Public Service Board in November 2007
 - Public Service Board approved on 2/11/09
- Maine Power Reliability Program
 - Project filed with the Maine Public Utility Commission on 7/1/08
 - Maine PUC approved most of the project on 6/10/10
 - Hearings continue on some portions of the project (Lewiston Loop, Three Rivers, Surowiec-Raven Farm)
 - Proposed Plan Applications and TCAs need to be revised to reflect the new version of the project

Operable Capacity Analysis

Fall 2010-Spring 2011 Operable Capacity Analysis (MW)

	September-10 ² 50/50 Forecast (Reference Load)	September-10 ² 90/10 Forecast (Extreme Load)
Generator Capacity Supply Obligation ¹	30,041	SAME
External Node Available capacity	342	SAME
Non Commercial Supply	0	SAME
Planned and other known outage MW ³	1,500	SAME
Allowance for Unplanned Outages	2,100	SAME
Generation at Risk Due to Gas Supply	0	SAME
Net Capacity ⁴	26,780	SAME
Peak Load Exposure (adjusted for Other Demand Resources)	26,618	28,738 (+2,120)
Reserve Requirement	1,800	SAME
Operable Capacity Required	28,418	30,538 (+2,120)
Operable Capacity Margin ⁴	(1,640)	(3,760) (-2,120)

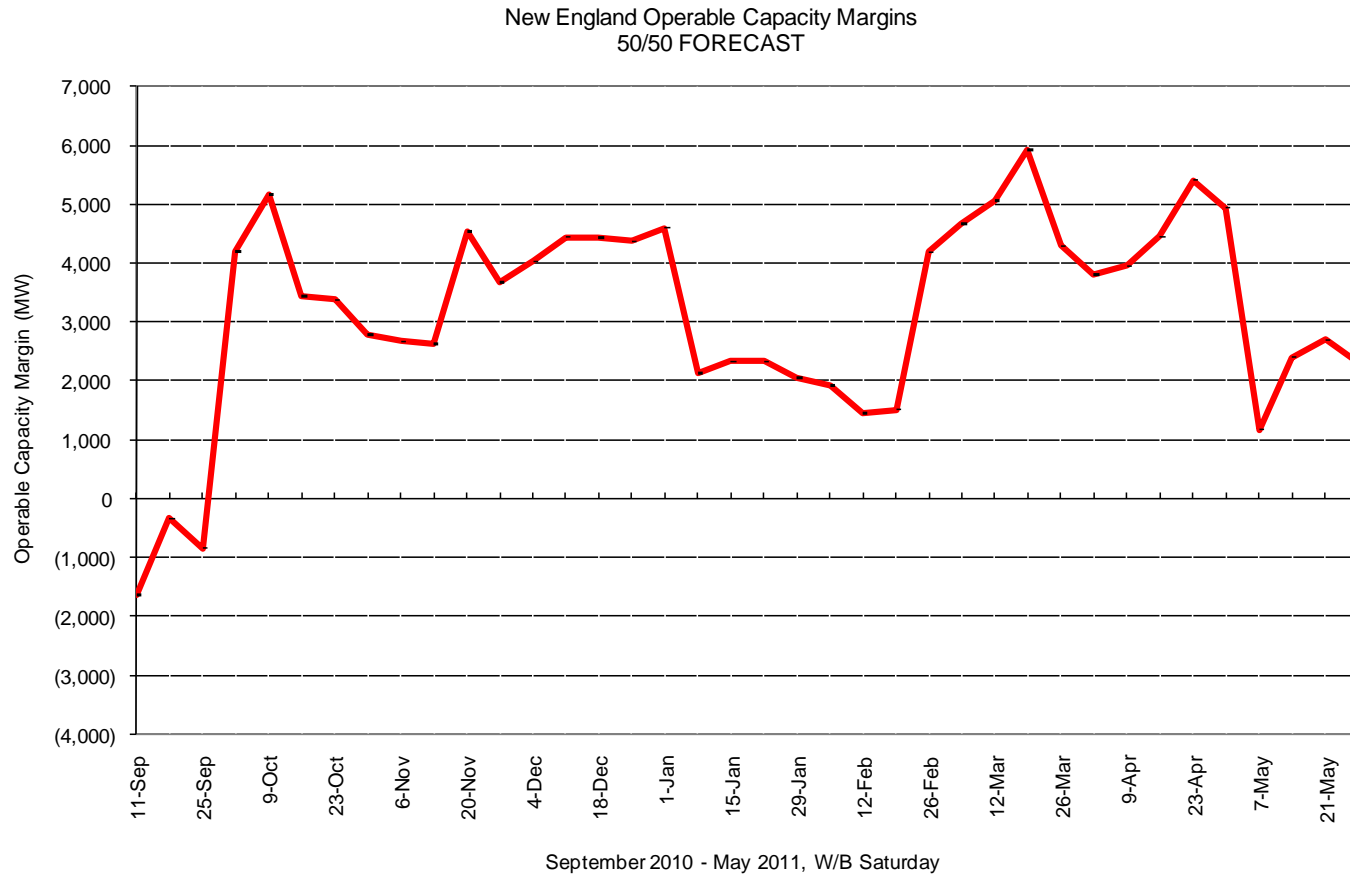
¹ Generator Capacity Supply Obligation is based on data as of September 1, 2010 and does not include Capacity Supply Obligations associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

² Based on week with lowest Operable Capacity Margin, week beginning September 11th.

³ Rounded to the nearest hundred.

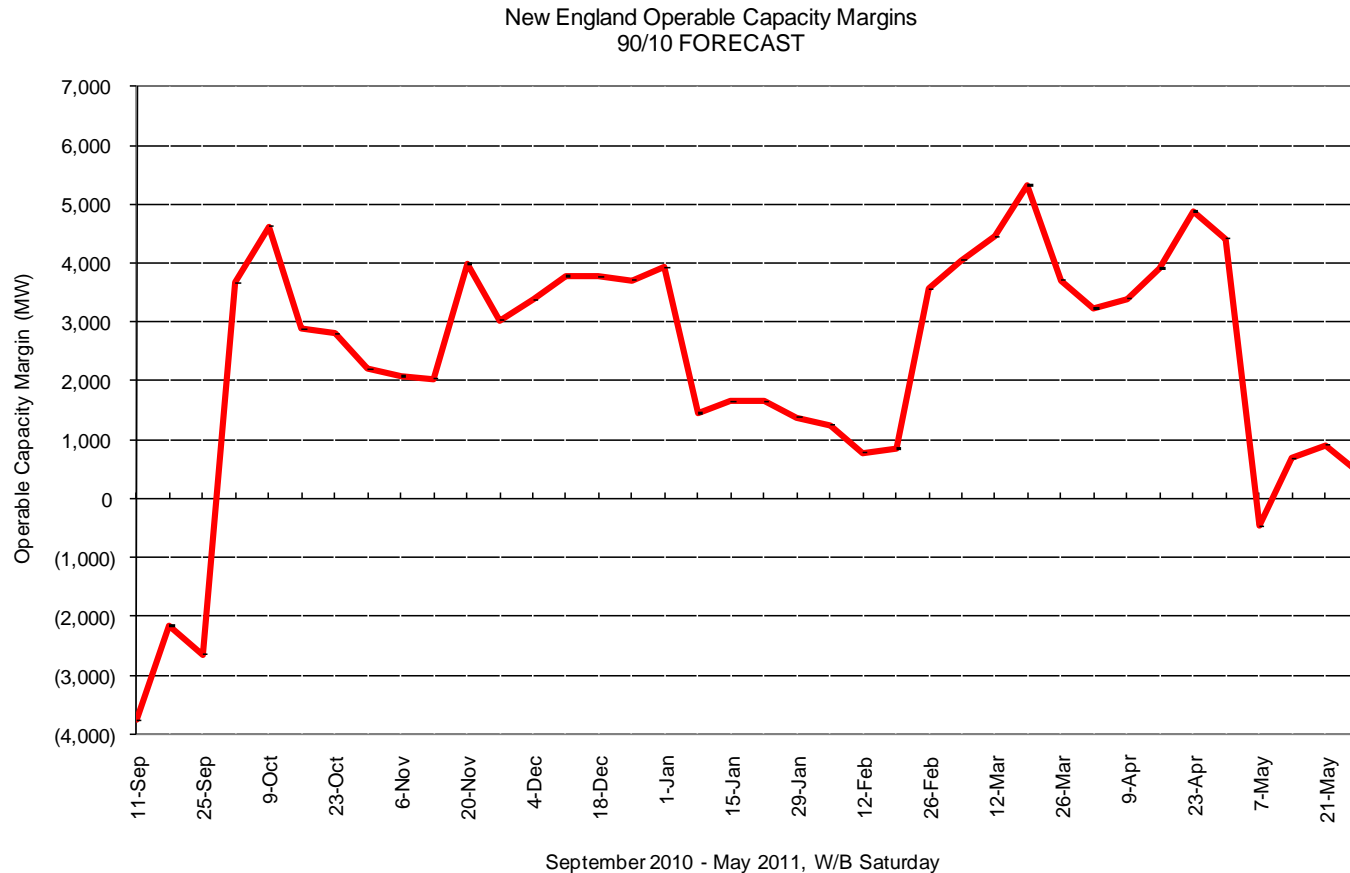
⁴ Rounded to the nearest ten

Fall 2010-Spring 2011 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)



Note: Based on data as of September 1, 2010. Does not include Settlement Only Generators and Active Demand Response.

Fall 2010-Spring 2011 Operable Capacity Analysis (MW) 90/10 Forecast (Extreme)



Note: Based on data as of September 1, 2010. Does not include Settlement Only Generators and Active Demand Response.

Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 1 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	Implement Power Caution and Resources with a CSO prepare to provide capacity and notify “Settlement Only” generators with a CSO to monitor reserve pricing to meet those obligations. Begin to allow depletion of 30-minute reserve.	0 ¹ 600 ²
2	Dispatch real time Demand Resources.	670 ³
3	Voluntary Load Curtailment of Market Participants’ facilities.	40
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-Control-Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	130 ⁴ 520 ³
7	Request generating resources not subject to a Capacity Supply Obligation to voluntarily provide energy for reliability purposes	0
8	Voltage Reduction requiring < 10 minutes	270 ⁴
9	Voluntary Load Curtailment by Large Industrial and Commercial Customers. Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency.	200 ² 5

Possible Relief Under OP4 based on OP4 Appendix A

OP 4 Action Number	Page 2 of 2 Action Description	Amount Assumed Obtainable Under OP 4 (MW)
10	Radio and TV Appeal	200
11	Request State Governors to Reinforce Power Warning Appeals.	100
Total		3,735

Based on results of the April Bilateral and Reconfiguration auctions for June CSO

NOTES:

1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are reviewed on a quarterly basis; actual available MW amounts can be viewed using the demand response dispatch software. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
4. The MW values are based on a 26,618 MW system load and the most recent voltage reduction test % achieved.

Appendix

Fall 2010-Spring 2011 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

September 7, 2010 - 50/50 FORECAST

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August.

STUDY WEEK (Week Beginning, Saturday)	OPCAP SUPPLY						LOAD OBLIGATIONS				OPCAP MARGINS					
	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL OPCAP MW	NON COMMERCIAL CAPACITY MW	KNOWN OUTAGES	UNPLANNED OUTAGES MW	GEN RISK DUE TO GAS SUP MW	EXPORT LTD AVAIL OPCAP MW(with no outages <15 days	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMEN T MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL- TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]	
09/11/2010	30,041	342	0	1,500	2,100	0	28,516	26,780	26,618	1,800	28,418	(1,640)	670	(970)	520	(450)
09/18/2010	30,041	342	0	4,100	2,100	0	25,986	24,180	22,722	1,800	24,522	(340)	670	330	520	850
09/25/2010	30,291	300	0	4,200	2,800	0	26,135	23,590	22,632	1,800	24,432	(840)	670	(170)	520	350
10/02/2010	30,291	300	0	5,000	2,800	0	25,263	22,790	16,793	1,800	18,593	4,200	670	4,870	520	5,390
10/09/2010	30,291	300	0	4,000	2,800	0	26,333	23,790	16,829	1,800	18,629	5,160	670	5,830	520	6,350
10/16/2010	30,291	300	0	4,800	2,800	0	25,517	22,990	17,748	1,800	19,548	3,440	670	4,110	520	4,630
10/23/2010	30,291	300	0	4,500	2,800	0	25,804	23,290	18,110	1,800	19,910	3,380	670	4,050	520	400
10/30/2010	30,196	300	0	4,000	3,600	0	26,245	22,900	18,315	1,800	20,115	2,780	670	3,450	520	400
11/06/2010	30,196	300	0	4,000	3,600	0	26,194	22,900	18,430	1,800	20,230	2,670	670	3,340	520	400
11/13/2010	30,196	300	0	3,700	3,600	0	26,527	23,200	18,772	1,800	20,572	2,630	670	3,300	520	400
11/20/2010	30,196	300	0	3,000	3,600	0	27,225	23,900	17,555	1,800	19,355	4,540	670	5,210	520	400
11/27/2010	30,196	300	0	1,200	3,600	0	29,032	25,700	20,234	1,800	22,034	3,670	670	4,340	520	400
12/04/2010	30,394	368	0	1,300	3,200	0	29,119	26,260	20,433	1,800	22,233	4,030	670	4,700	520	400
12/11/2010	30,394	368	0	600	3,200	0	29,757	26,960	20,720	1,800	22,520	4,440	670	5,110	520	400
12/18/2010	30,394	368	0	600	3,200	0	29,789	26,960	20,731	1,800	22,531	4,430	670	5,100	520	400
12/25/2010	30,394	368	0	600	3,200	0	29,795	26,960	20,793	1,800	22,593	4,370	670	5,040	520	400
01/01/2011	30,394	368	0	500	2,800	0	29,848	27,460	21,064	1,800	22,864	4,600	670	5,270	520	400
01/08/2011	30,394	368	0	500	2,800	2,000	29,848	25,460	21,526	1,800	23,326	2,130	670	2,800	520	400
01/15/2011	30,394	368	0	300	2,800	2,000	30,125	25,660	21,526	1,800	23,326	2,330	670	3,000	520	400
01/22/2011	30,394	368	0	300	2,800	2,000	30,123	25,660	21,526	1,800	23,326	2,330	670	3,000	520	400
01/29/2011	30,394	368	0	500	3,100	2,000	29,853	25,160	21,305	1,800	23,105	2,050	670	2,720	520	400
02/05/2011	30,394	368	0	900	3,100	2,000	29,484	24,760	21,040	1,800	22,840	1,920	670	2,590	520	400
02/12/2011	30,394	368	0	1,400	3,100	2,000	28,995	24,260	21,011	1,800	22,811	1,450	670	2,120	520	400
02/19/2011	30,394	368	0	1,600	3,100	2,000	28,841	24,060	20,751	1,800	22,551	1,510	670	2,180	520	400
02/26/2011	30,394	368	0	1,900	3,100	0	28,481	25,760	19,770	1,800	21,570	4,190	670	4,860	520	400
03/05/2011	30,394	300	0	2,600	2,200	0	27,822	25,890	19,424	1,800	21,224	4,670	670	5,340	520	400
03/12/2011	30,394	300	0	2,400	2,200	0	28,024	26,090	19,229	1,800	21,029	5,060	670	5,730	520	400
03/19/2011	30,394	300	0	1,900	2,200	0	28,477	26,590	18,867	1,800	20,667	5,920	670	6,590	520	400
03/26/2011	30,196	300	0	3,400	2,700	0	26,823	24,400	18,306	1,800	20,106	4,290	670	4,960	520	400
04/02/2011	30,196	300	0	4,400	2,700	0	25,778	23,400	17,803	1,800	19,603	3,800	670	4,470	520	400
04/09/2011	30,196	300	0	4,500	2,700	0	25,698	23,300	17,553	1,800	19,353	3,950	670	4,620	520	400
04/16/2011	30,196	300	0	4,500	2,700	0	25,704	23,300	17,047	1,800	18,847	4,450	670	5,120	520	400
04/23/2011	30,196	300	0	3,800	2,700	0	26,359	24,000	16,785	1,800	18,585	5,410	670	6,080	520	400
04/30/2011	30,196	300	0	3,600	3,400	0	26,579	23,500	16,758	1,800	18,558	4,940	670	5,610	520	400
05/07/2011	30,196	300	0	3,800	3,400	0	26,407	23,300	20,325	1,800	22,125	1,170	670	1,840	520	400
05/14/2011	30,196	300	0	1,600	3,400	0	28,622	25,500	21,296	1,800	23,096	2,400	670	3,070	520	400
05/21/2011	30,196	300	0	400	3,400	0	29,771	26,700	22,198	1,800	23,998	2,700	670	3,370	520	400
05/28/2011	30,196	300	0	0	3,400	0	30,184	27,100	22,976	1,800	24,776	2,320	670	2,990	520	400

- Available OPCAP MW based on resource Capacity Supply Obligations, CSO, from Forward Capacity Tracking System, FCTS. Does not include Settlement Only Generators. (separate LTOCM run without any generator outages, tab Case Output-System Results-EXPORT LTD AVAIL OPCAP MW)
- External Node Available OPCAP MW based on external Capacity Supply Obligations, CSO. (LTOCM application Case Output-System Results-EXTERNAL NODE AVAIL OPCAP MW)
- New resources that have not yet acquired a CSO but will become commercial in the future.
- Planned Outages includes outages scheduled greater than or equal to 15 days in advance.
- Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A. (LTOCM application Case Output-System Results-UNPLANNED OUTAGES MW)
- Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions. (LTOCM application Case Output-System Results-GEN RISK DUE TO GAS SUP MW)
- Total OpCap Supply Available per the formula (1 + 2 + 3 - 4 - 5 + 6 = 7)
- Peak Load Exposure per data included in the 2010 CELT Report. (LTOCM application-Case Output-System Results-LOAD FORECAST MW)
- Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency. (LTOCM application Case Output-System Results-OPER RESERVE REQUIREMENT MW)
- Total Load Obligation per the formula (8 + 9 = 10)
- Net OPCAP Supply minus Net Load Obligation (7 - 10 = 11)
- OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
- OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (11 - 12 = 13).
- OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
- OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (13 - 14 = 15). This does not include Emergency Energy Transactions (EETs).

Fall 2010-Spring 2011 Operable Capacity Analysis (MW) 90/10 Forecast (Reference)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

September 7, 2010 - 90/10 FORECAST

This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, and August.

STUDY WEEK (Week Beginning, Saturday)	OPCAP SUPPLY						LOAD OBLIGATIONS			OPCAP MARGINS						
	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL OPCAP MW	NON COMMERCIAL CAPACITY MW	KNOWN OUTAGES	UNPLANNED OUTAGES MW	GEN RISK DUE TO GAS SUP MW	EXPORT LTD AVAIL OPCAP MW (with no outages <15 days	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT T MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL- TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
09/11/2010	30,041	342	0	1,500	2,100	0	28,516	26,780	28,738	1,800	30,538	(3,780)	670	(3,090)	520	(2,570)
09/18/2010	30,041	342	0	4,100	2,100	0	25,986	24,180	24,538	1,800	26,338	(2,160)	670	(1,490)	520	(970)
09/25/2010	30,291	300	0	4,200	2,800	0	26,135	23,590	24,441	1,800	26,241	(2,650)	670	(1,980)	520	(1,460)
10/02/2010	30,291	300	0	5,000	2,800	0	25,263	22,790	17,328	1,800	19,128	3,660	670	4,330	520	4,850
10/09/2010	30,291	300	0	4,000	2,800	0	26,333	23,790	17,365	1,800	19,165	4,620	670	5,290	520	5,810
10/16/2010	30,291	300	0	4,800	2,800	0	25,517	22,990	18,312	1,800	20,112	2,880	670	3,550	520	4,070
10/23/2010	30,291	300	0	4,500	2,800	0	25,804	23,290	18,685	1,800	20,485	2,800	670	3,470	520	400
10/30/2010	30,196	300	0	4,000	3,600	0	26,245	22,900	18,897	1,800	20,697	2,200	670	2,870	520	400
11/06/2010	30,196	300	0	4,000	3,600	0	26,194	22,900	19,015	1,800	20,815	2,080	670	2,750	520	400
11/13/2010	30,196	300	0	3,700	3,600	0	26,527	23,200	19,368	1,800	21,168	2,030	670	2,700	520	400
11/20/2010	30,196	300	0	3,000	3,600	0	27,225	23,900	18,112	1,800	19,912	3,990	670	4,660	520	400
11/27/2010	30,196	300	0	1,200	3,600	0	29,032	25,700	20,874	1,800	22,674	3,030	670	3,700	520	400
12/04/2010	30,394	368	0	1,300	3,200	0	29,119	26,260	21,079	1,800	22,879	3,380	670	4,050	520	400
12/11/2010	30,394	368	0	600	3,200	0	29,757	26,960	21,375	1,800	23,175	3,780	670	4,450	520	400
12/18/2010	30,394	368	0	600	3,200	0	29,789	26,960	21,386	1,800	23,186	3,770	670	4,440	520	400
12/25/2010	30,394	368	0	600	3,200	0	29,795	26,960	21,450	1,800	23,250	3,710	670	4,380	520	400
01/01/2011	30,394	368	0	500	2,800	0	29,848	27,460	21,730	1,800	23,530	3,930	670	4,600	520	400
01/08/2011	30,394	368	0	500	2,800	2,000	29,848	25,460	22,206	1,800	24,006	1,450	670	2,120	520	400
01/15/2011	30,394	368	0	300	2,800	2,000	30,125	25,660	22,206	1,800	24,006	1,650	670	2,320	520	400
01/22/2011	30,394	368	0	300	2,800	2,000	30,123	25,660	22,206	1,800	24,006	1,650	670	2,320	520	400
01/29/2011	30,394	368	0	500	3,100	2,000	29,853	25,160	21,978	1,800	23,778	1,380	670	2,050	520	400
02/05/2011	30,394	368	0	900	3,100	2,000	29,484	24,760	21,705	1,800	23,505	1,250	670	1,920	520	400
02/12/2011	30,394	368	0	1,400	3,100	2,000	28,995	24,260	21,676	1,800	23,476	780	670	1,450	520	400
02/19/2011	30,394	368	0	1,600	3,100	2,000	28,841	24,060	21,407	1,800	23,207	850	670	1,520	520	400
02/26/2011	30,394	368	0	1,900	3,100	0	28,481	25,760	20,396	1,800	22,196	3,560	670	4,230	520	400
03/05/2011	30,394	300	0	2,600	2,200	0	27,822	25,890	20,039	1,800	21,839	4,050	670	4,720	520	400
03/12/2011	30,394	300	0	2,400	2,200	0	28,024	26,090	19,838	1,800	21,638	4,450	670	5,120	520	400
03/19/2011	30,394	300	0	1,900	2,200	0	28,477	26,590	19,465	1,800	21,265	5,320	670	5,990	520	400
03/26/2011	30,196	300	0	3,400	2,700	0	26,823	24,400	18,887	1,800	20,687	3,710	670	4,380	520	400
04/02/2011	30,196	300	0	4,400	2,700	0	25,778	23,400	18,368	1,800	20,168	3,230	670	3,900	520	400
04/09/2011	30,196	300	0	4,500	2,700	0	25,698	23,300	18,111	1,800	19,911	3,390	670	4,060	520	400
04/16/2011	30,196	300	0	4,500	2,700	0	25,704	23,300	17,590	1,800	19,390	3,910	670	4,580	520	400
04/23/2011	30,196	300	0	3,800	2,700	0	26,359	24,000	17,319	1,800	19,119	4,880	670	5,550	520	400
04/30/2011	30,196	300	0	3,600	3,400	0	26,579	23,500	17,292	1,800	19,092	4,410	670	5,080	520	400
05/07/2011	30,196	300	0	3,800	3,400	0	26,407	23,300	21,968	1,800	23,768	(470)	670	200	520	400
05/14/2011	30,196	300	0	1,600	3,400	0	28,622	25,500	23,016	1,800	24,816	680	670	1,350	520	400
05/21/2011	30,196	300	0	400	3,400	0	29,771	26,700	23,988	1,800	25,788	910	670	1,580	520	400
05/28/2011	30,196	300	0	0	3,400	0	30,184	27,100	24,844	1,800	26,644	460	670	1,130	520	400

- Available OPCAP MW based on resource Capacity Supply Obligations, CSO, from Forward Capacity Tracking System, FCTS. Does not include Settlement Only Generators. (separate LTOCM run without any generator outages, tab Case Output-System Results-column LZ EXPORT LTD AVAIL OPCAP MW)
- External Node Available OPCAP MW based on external Capacity Supply Obligations, CSO. (LTOCM application Case Output-System Results-EXTERNAL NODE AVAIL OPCAP MW)
- New resources that have not yet acquired a CSO but will become commercial in the future.
- Planned Outages includes outages scheduled greater than or equal to 15 days in advance.
- Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A. (LTOCM application Case Output-System Results-UNPLANNED OUTAGES MW)
- Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions. (LTOCM application Case Output-System Results-GEN RISK DUE TO GAS SUP MW)
- Total OpCap Supply Available per the formula (1 + 2 + 3 - 4 - 5 - 6 = 7)
- Peak Load Exposure per data included in the 2010 CELT Report. (LTOCM application-Case Output-System Results-LOAD FORECAST MW)
- Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency. (LTOCM application Case Output-System Results-OPER RESERVE REQUIREMENT MW)
- Total Load Obligation per the formula (8 + 9 = 10)
- Net OPCAP Supply minus Net Load Obligation (7 - 10 = 11)
- OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
- OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (11 - 12 = 13).
- OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
- OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (13 - 14 = 15). This does not include Emergency Energy Transactions (EET).