

NEPOOL Participants Committee Report

March 2010

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Senior Vice President and Chief Operating Officer

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Highlights

- **Day-Ahead (DA), Real-Time (RT) Prices and Transactions**

- February natural gas prices over the period were 11.4% lower while oil prices were 4.1% lower than January 2010 average values
- Average RT Hub Locational Marginal Prices (LMPs) over the period were down 13% from January 2010 averages

All data through February 24th unless otherwise noted.

Underlying natural gas data furnished by:



Highlights (cont'd.)

- **Daily Net Commitment Period Compensation (NCPC)***
 - February payments total \$1.0M over the period, down \$3.0M from January
 - First Contingency payments total \$868K, down \$3.1M from January
 - \$800K paid to internal resources, down \$3M from January
 - \$37K charged to DALO, \$752K to RT Deviations
 - \$68K paid to resources at external locations, down \$69K from January
 - \$68K charged to RT Deviations
 - Second Contingency payments total \$156K, up \$156K from January
 - Distribution payments total \$20K, up \$17K from January
 - NCPC payments as percent of Energy Market value were 0.2%

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

Highlights (cont'd.)

- Planning Advisory Committee (PAC) meeting on the Regional Planning Process planned for February 24 has been rescheduled to March 8
- Economic Study Requests to be submitted to the ISO by April 1
- Eastern Interconnection Planning Collaborative (EIPC) is moving forward with initial model development

Highlights (cont'd.)

- Following the accident at Kleen, the Manchester-Scovill Rock 345 kV line is in the process of being returned to the original configuration
 - This line's expected return to service date March 13
- The lowest Winter/Spring Operable Capacity Margin being calculated for the week beginning May 8th

System Operations

System Operations

<u>Weather Patterns:</u>	Boston	Temperature – Above Average Precipitation – Below Average	Hartford	Temperature – Above Average Precipitation – Average
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<u>Peak Load:</u>	19,255MW	February 8, 2010	19:00
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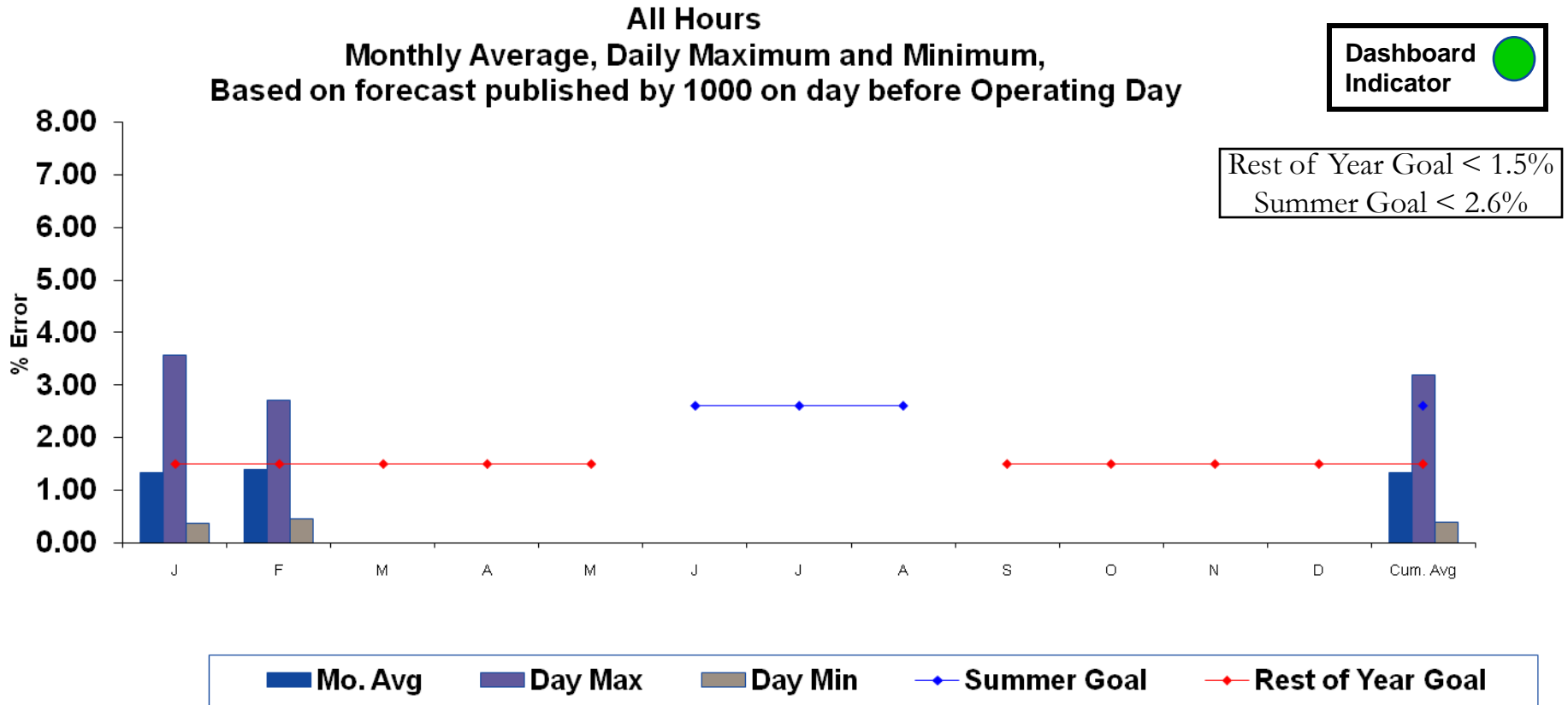
<u>Minimum Generation Emergencies :</u> None

<u>OP-4 Events</u>	None
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<u>MLCC2 Declared:</u>	
Feb 02,04,06,16,27,28 – Real time contract curtailment	

<u>NPCC Shared Activation of Reserve Events:</u>			
February 03	Loss of Neptune Cable	660 Mw	NYISO
February 18	Loss of Calvert Cliffs 1 & 2	1752Mw	PJM
February 26	Loss of Millstone 2	873 Mw	ISO-NE

2010 System Operations - Load Forecast Accuracy



	J	F	M	A	M	J	J	A	S	O	N	D	Avg	
Mo Avg	1.33	1.39											1.34	Mo Avg
Day Max	3.57	2.72											3.20	Day Max
Day Min	0.37	0.45											0.40	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.													1.43	

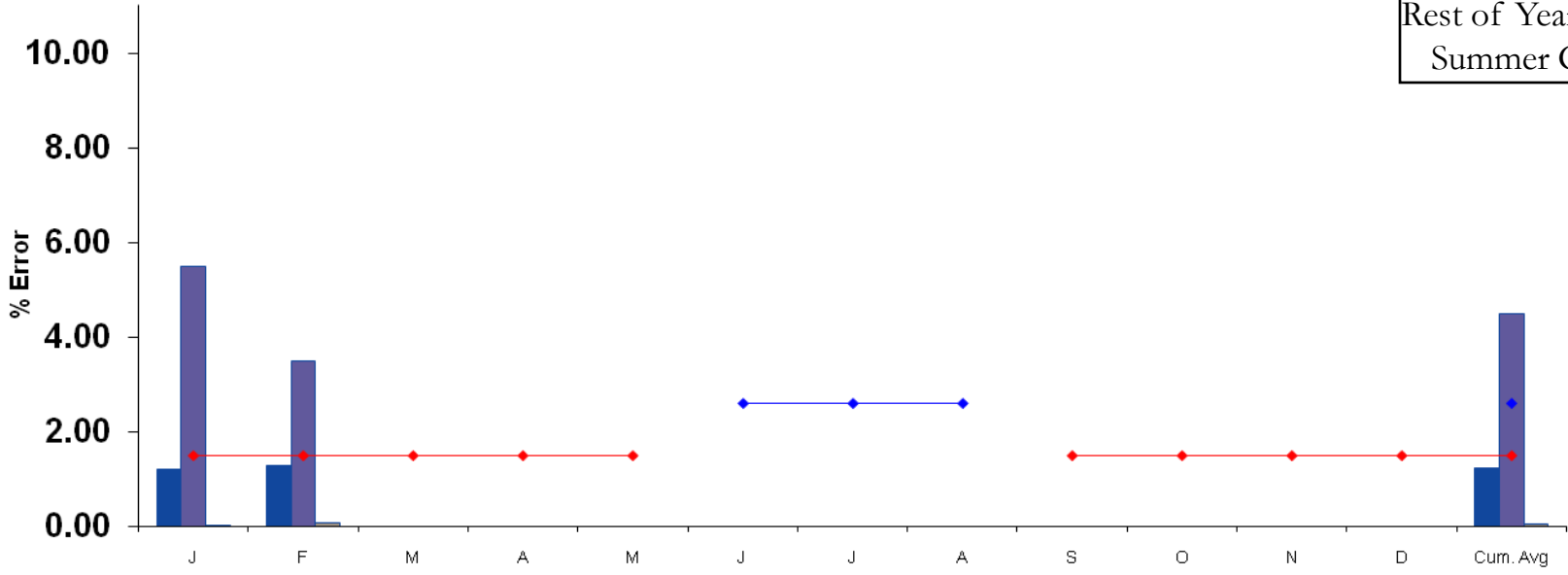
Contact: Steve Weaver														
Summer Goal = 2.6% Rest of Year Goal = 1.5%														
Summer consists of June, July and August-														

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%



■ 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	1.20	1.28											1.24
Day Max	5.49	3.49											4.50
Day Min	0.03	0.07											0.05
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													

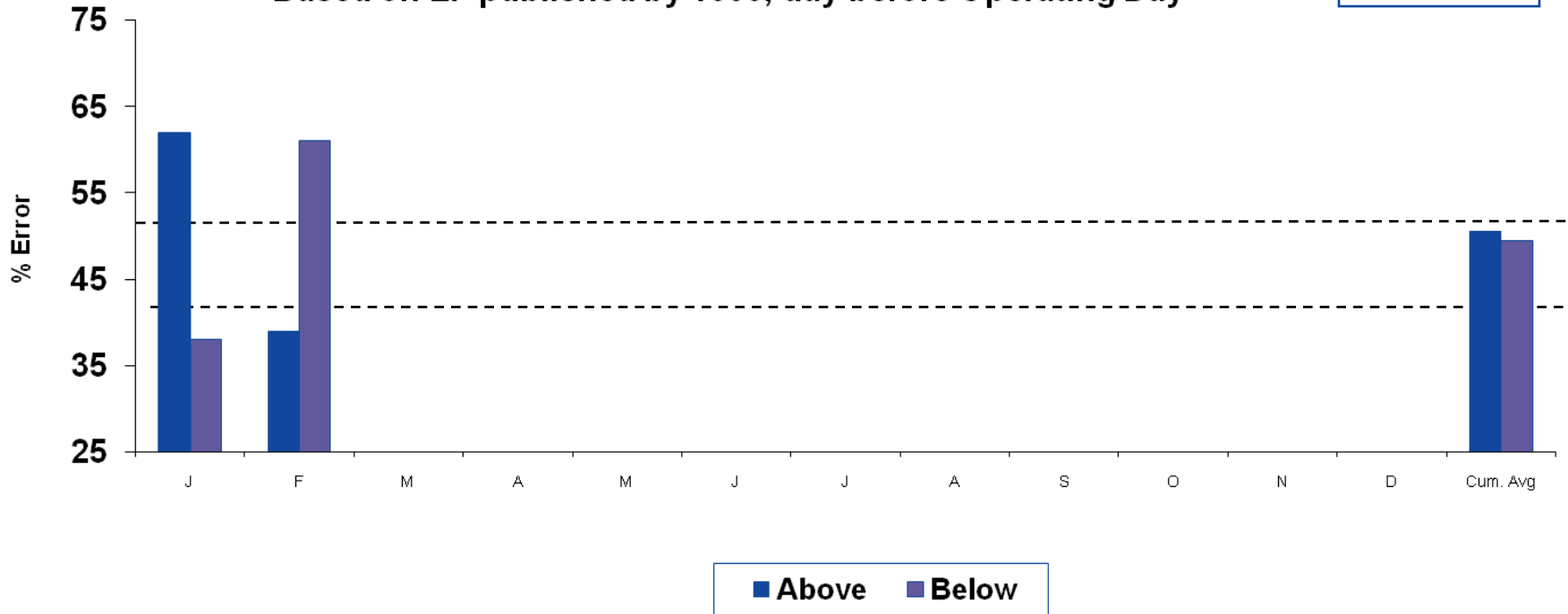
Contact: Steve Weaver

Summer Goal = 2.6% Rest of Year Goal = 1.5%
 Summer consists of June, July and August.

2010 System Operations - Load Forecast Accuracy

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

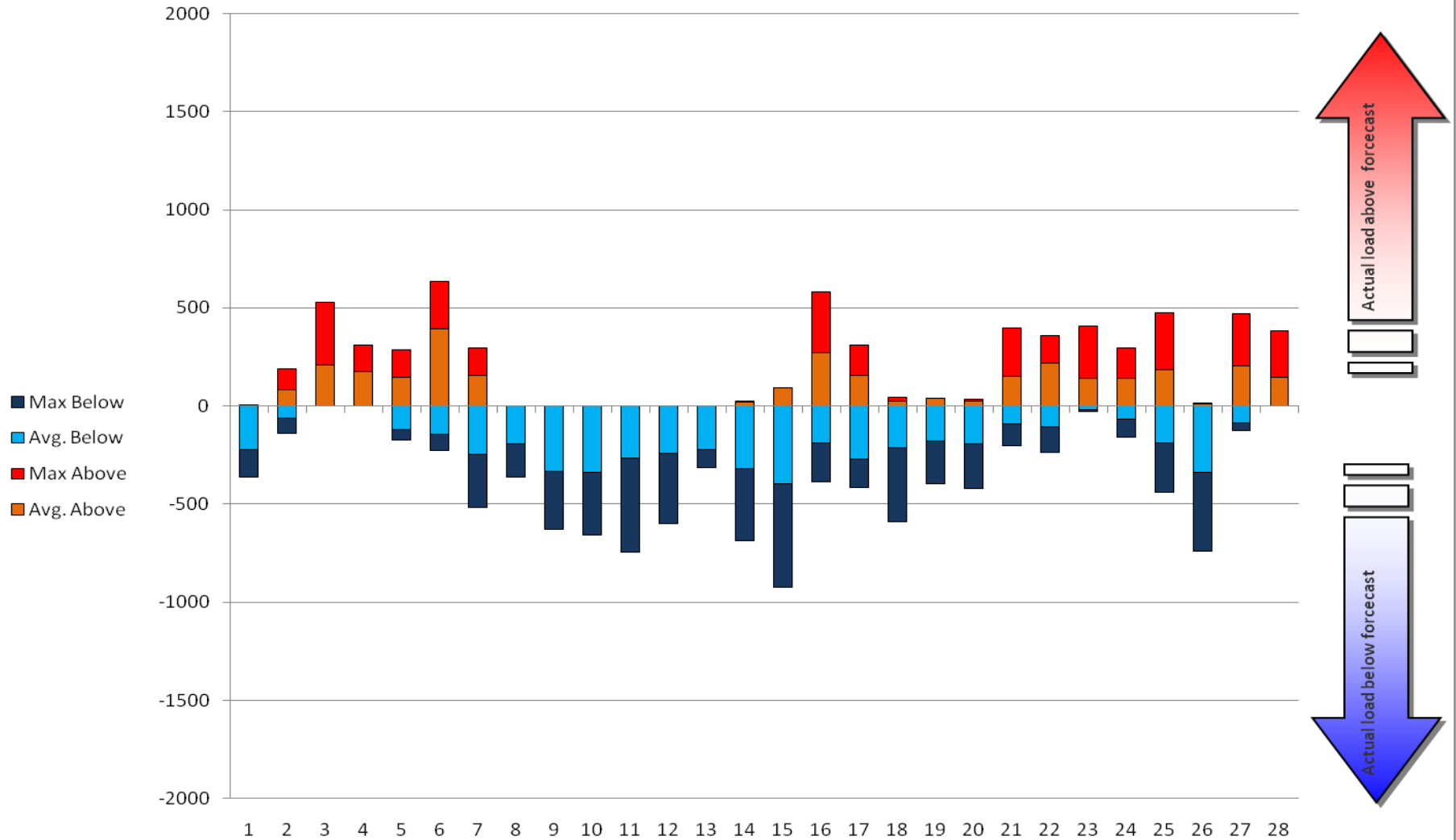
Target = 50%
Plus/Minus 5%



	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	62.0	39.0											51.0
Below %	38.0	61.0											49.0
Avg Above	178.0	106.0											143.0
Avg Below	-112.0	-181.0											-144.0
Avg All	74.0	-69.0											6.0

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

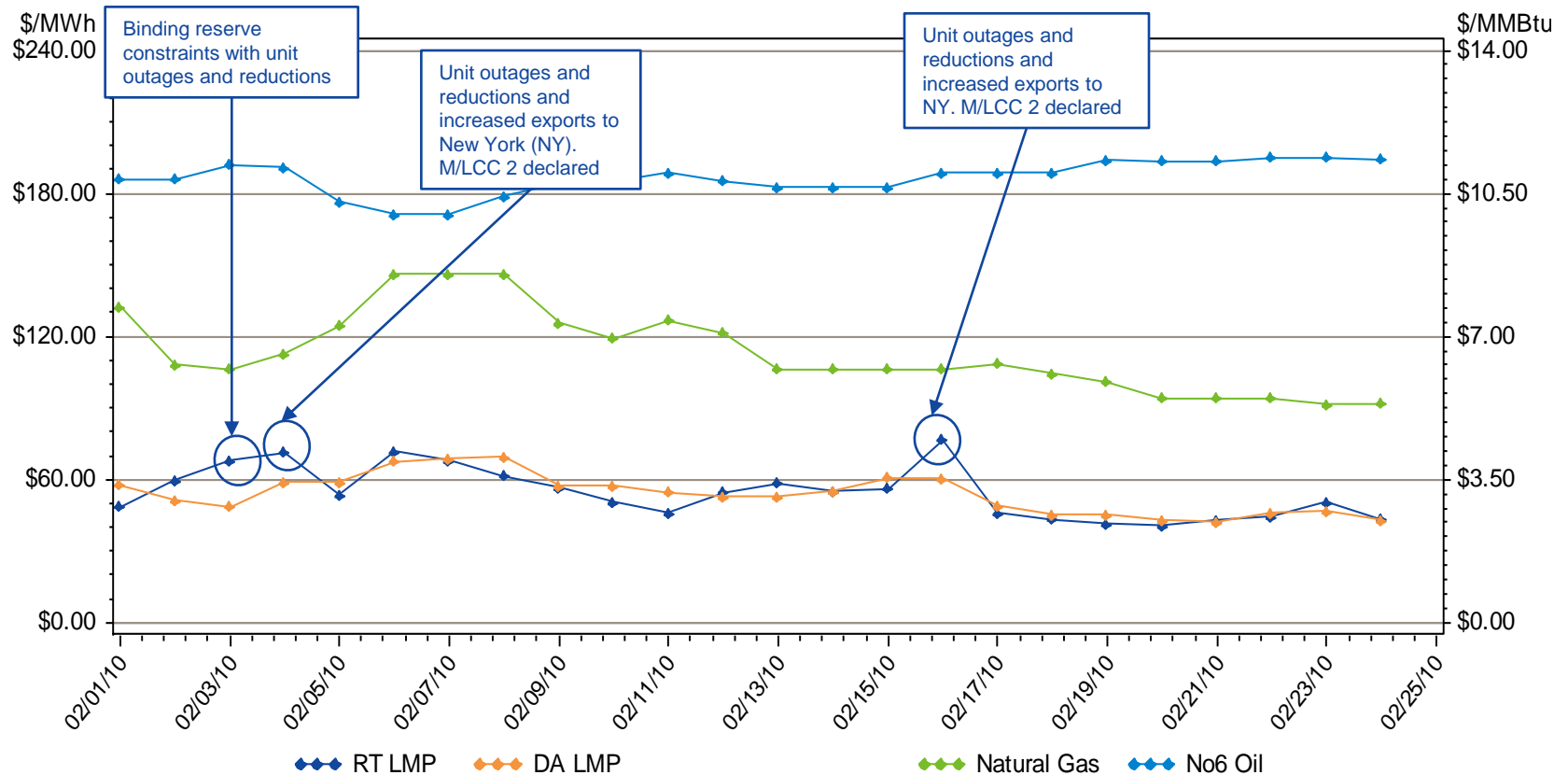
Deviation of Actual Load from Forecasted Load February 2010



ISO

Market Operations

DA and RT ISO-NE Hub Prices and Input Fuel Prices: February 1-24, 2010



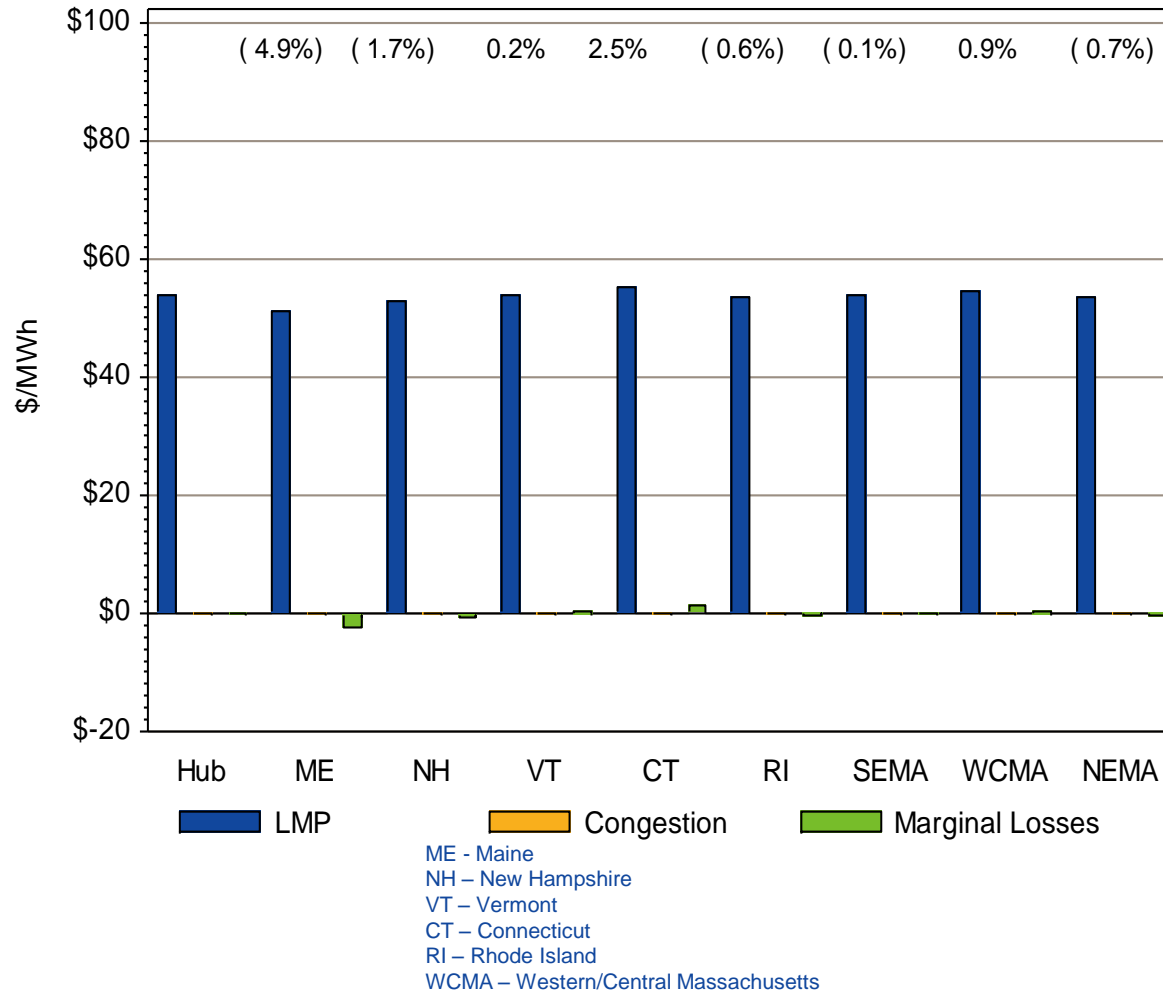
Underlying natural gas data furnished by:



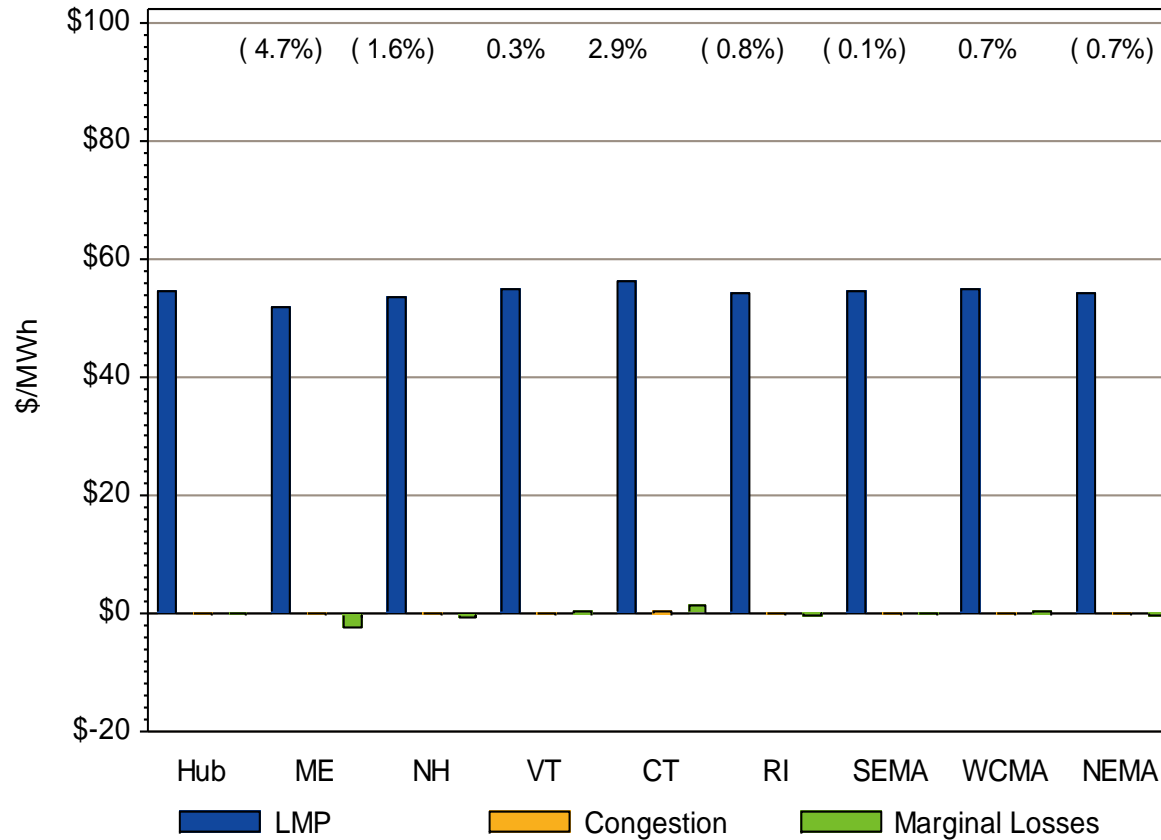
Average price difference over this period (DA-RT): \$-0.67
 Average price difference over this period ABS(DA-RT): \$5.42
 Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 10%

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 – February 2010

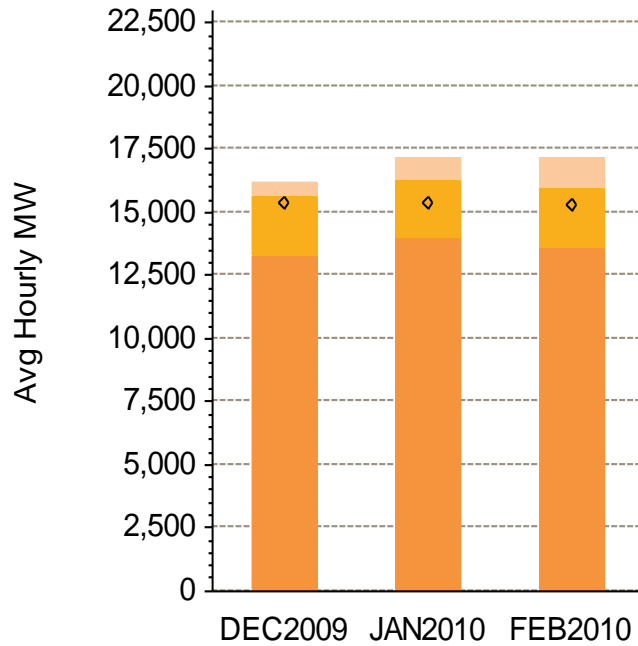


RT LMPs Average by Zone & Hub – February 2010



Components of Cleared DA Supply and Demand – Last Three Months

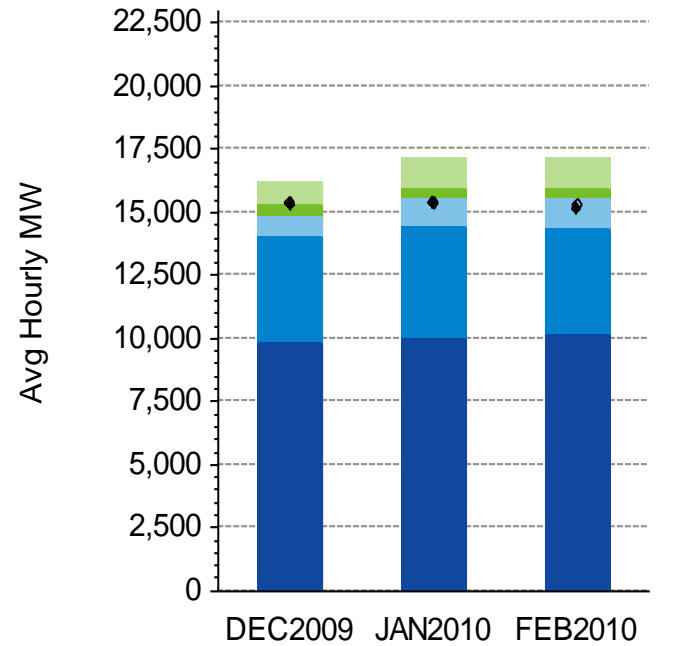
Supply



■ Gen ■ Incs
■ Imports ◇ DA Fcst Load

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

Demand

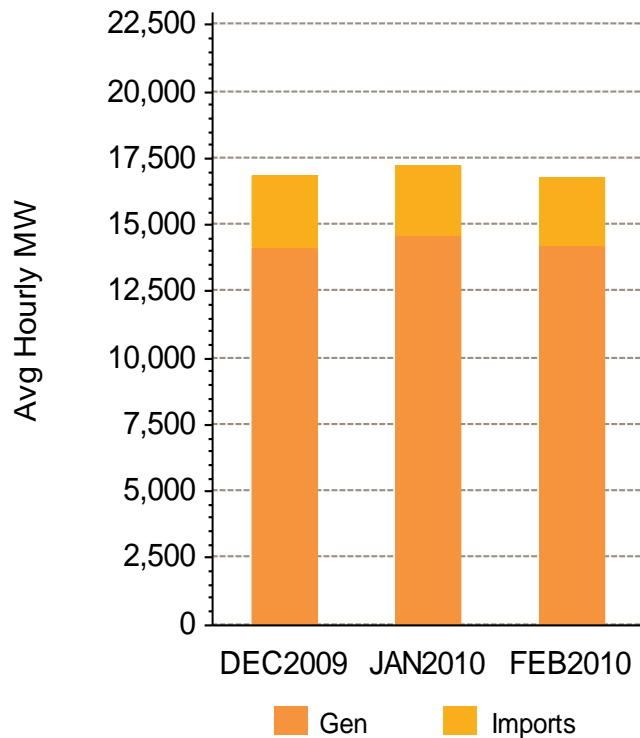


■ Fixed Dem ■ PrSens Dem ■ Decs
■ Losses ■ Exports ◇ Act Load

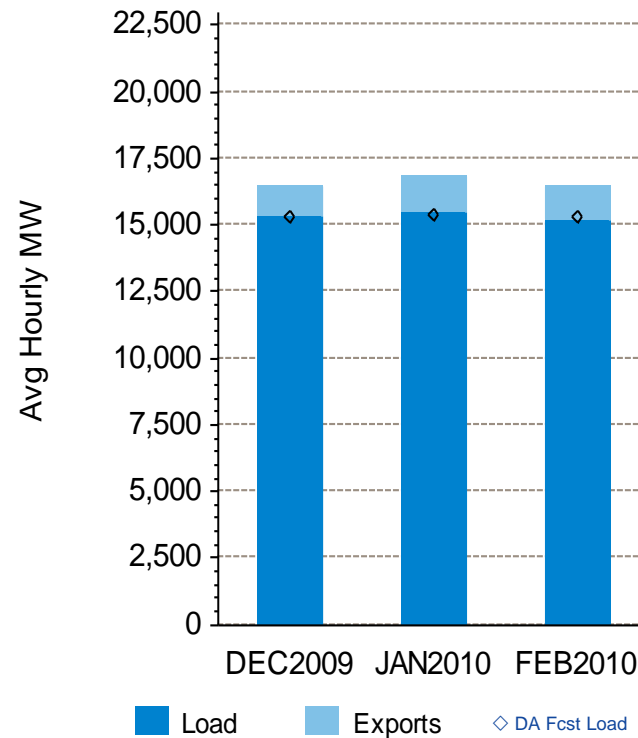
Fixed Dem – Fixed Demand
 PrSens Dem – Price Sensitive Demand
 Decs – Decrement Bids
 Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months

Supply

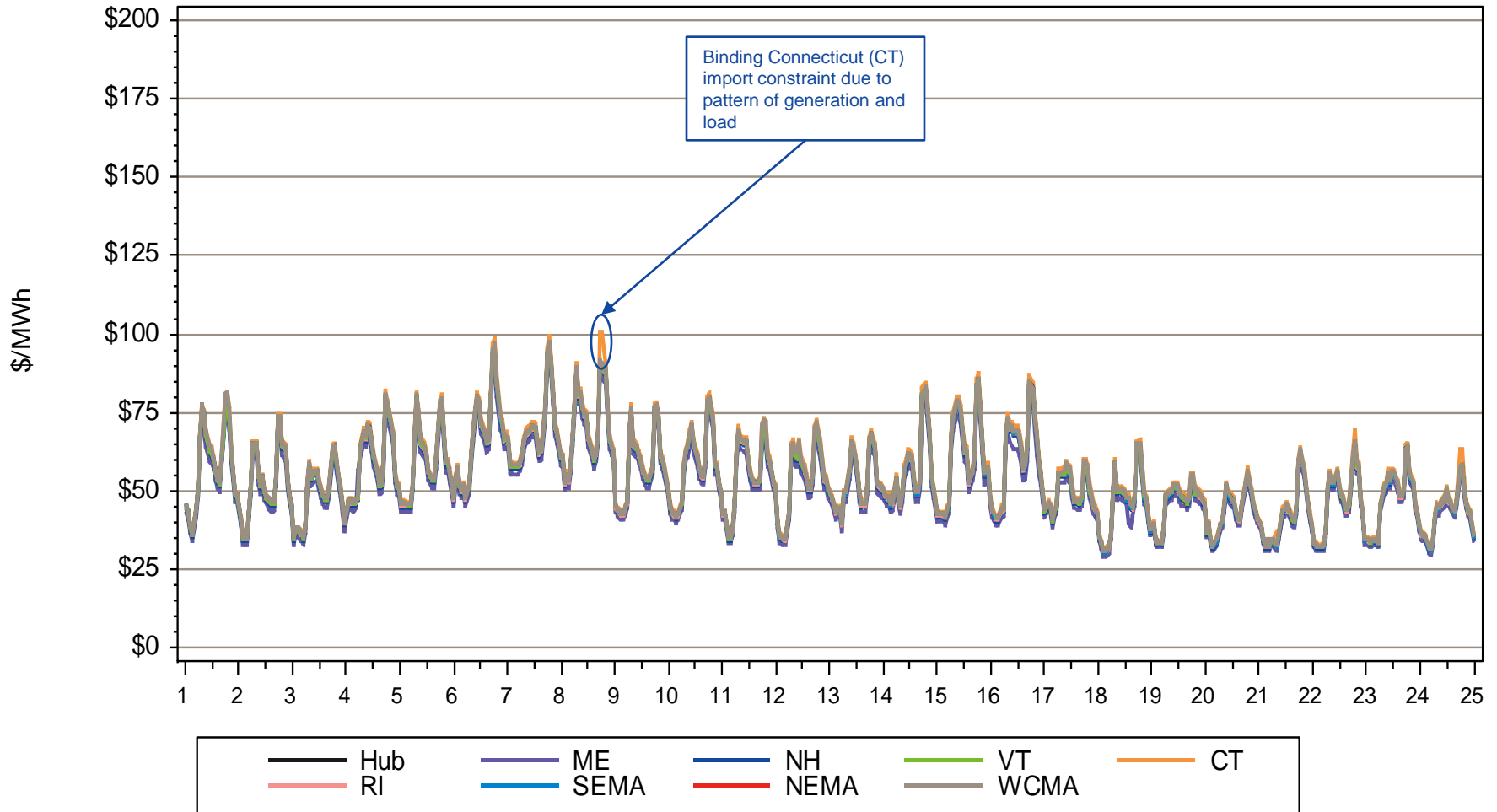


Demand



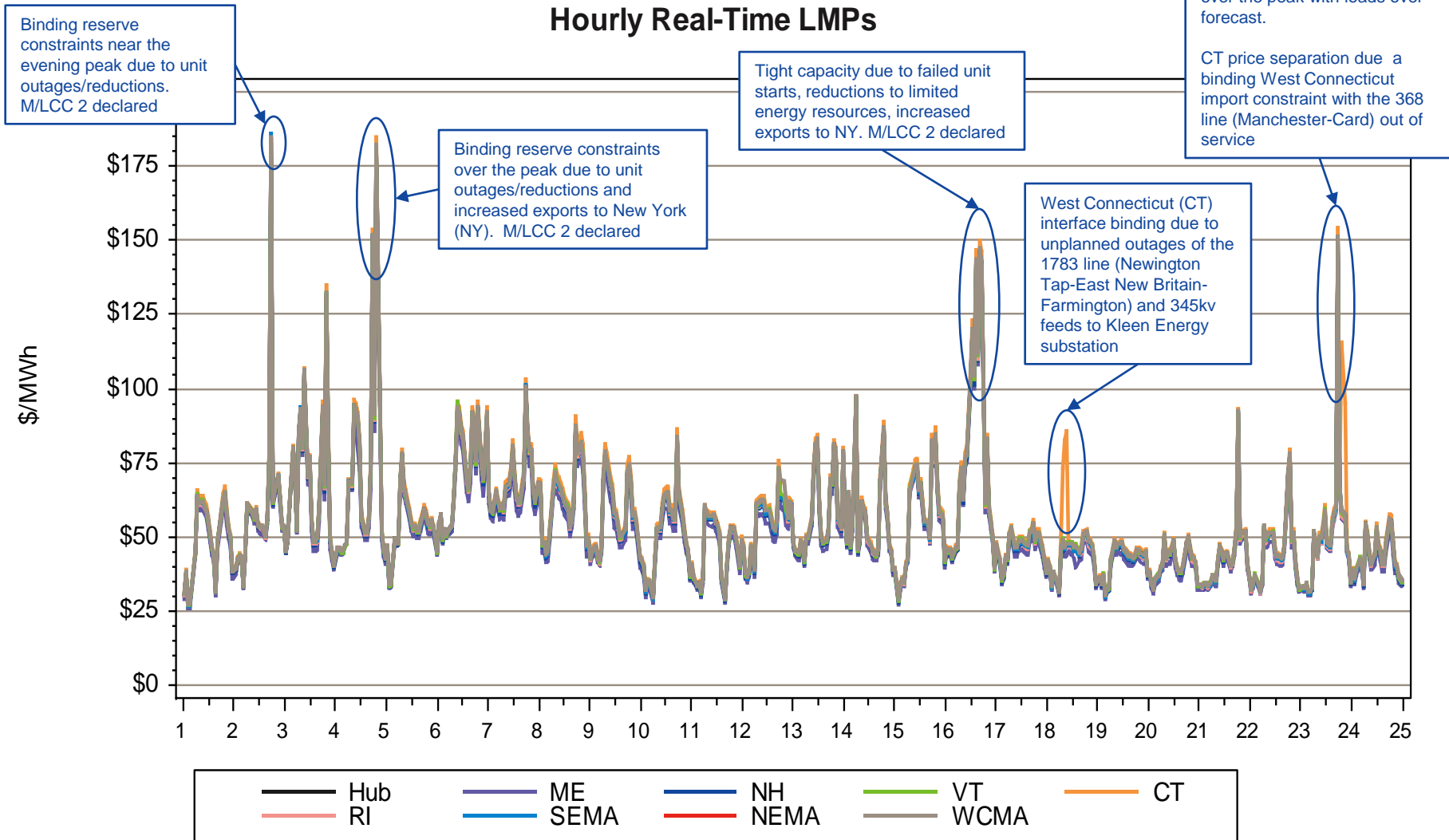
Hourly DA LMPs, February 1-24, 2009

Hourly Day-Ahead LMPs

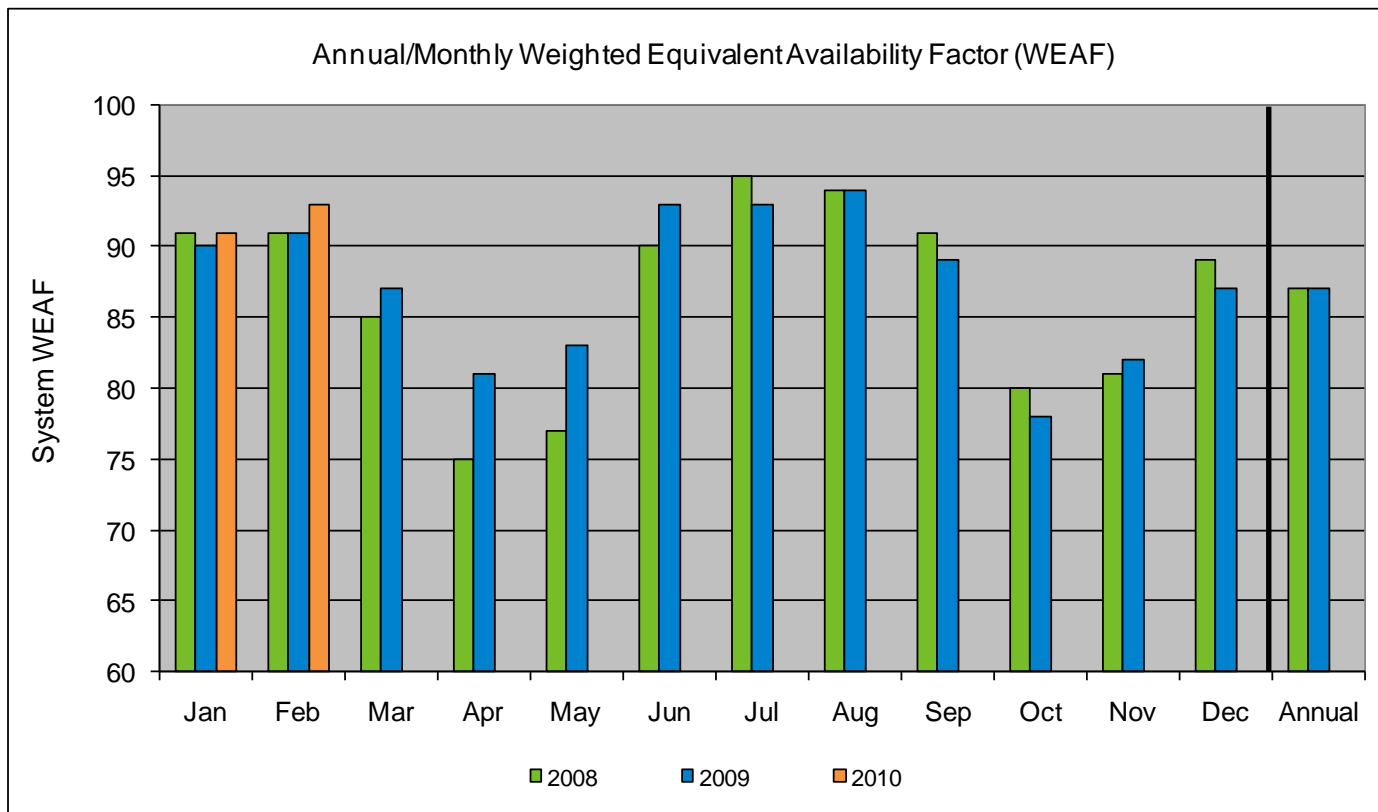


Hourly RT LMPs, February 1-24, 2010

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											92	2010
												87	2009
												87	2008
												90	2007

Back-up Detail

Load Response

Demand Response (as of March 1, 2010)

Ready To Respond*:			Approved**:	
Zone	Assets	Total MW	Assets	Total MW
CT	1,465	769.2	3	1.5
ME	132	522.1	1	0.4
NEMA	547	256.6	8	2.4
NH	203	102.5	0	0.0
RI	289	137.6	2	0.2
SEMA	393	132.6	0	0.0
VT	159	88.1	0	0.0
WCMA	519	265.2	3	1.4
Total	3,707	2,273.8	17	5.8

*Ready to Respond means the registration process is complete and the resource is eligible to participate in an Event

**Approved means the application for registration has been approved by ISO-NE

Demand Response (as of March 1, 2010)

Ready To Respond*:						Approved**:				
3,707 Assets 2,273.8 MW						17 Assets 05.8 MW				
Zone	Assets	RT Price	RT 30-Min	RT 2-Hour	Profiled	Assets	RT Price	RT 30-Min	RT 2-Hour	Profiled
CT	1,465	2.4	746.5	20.4	0.0	3	0.0	0.0	1.5	0.0
SWCT***	727	0.1	367.7	1.2	0.0	2	0.0	0.0	0.5	0.0
ME	132	0.0	399.3	111.8	11.0	1	0.0	0.4	0.0	0.0
NEMA	547	25.6	216.8	14.2	0.0	8	0.0	0.0	2.4	0.0
NH	203	4.5	92.6	5.4	0.0	0	0.0	0.0	0.0	0.0
RI	289	13.3	112.3	12.1	0.0	2	0.2	0.0	0.0	0.0
SEMA	393	8.2	107.5	16.8	0.0	0	0.0	0.0	0.0	0.0
VT	159	1.8	73.9	6.5	5.9	0	0.0	0.0	0.0	0.0
WCMA	519	14.8	214.6	35.9	0.0	3	0.0	0.0	1.4	0.0
Total	3,707	70.5	1,963.4	223.0	16.9	17	0.2	0.4	5.2	0.0

* Ready to Respond means the registration process is complete and the resource is eligible to participate in an Event

** Approved means the application for registration has been approved by ISO-NE

*** SWCT assets are included in CT values and are not included in Total

New Generation

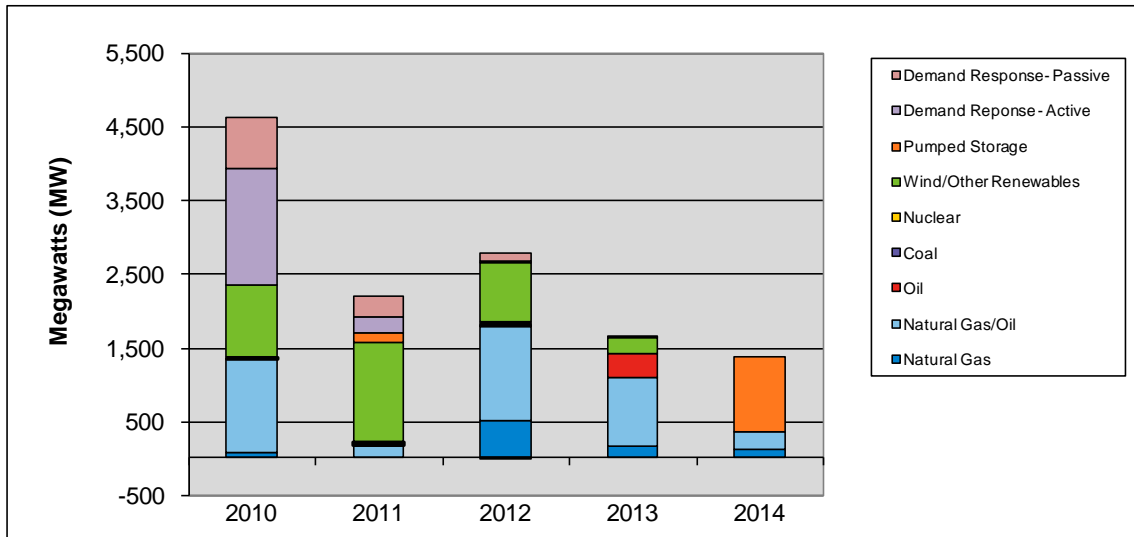
as of February 1, 2010

New Generation Update (as of Feb 1, 2010)

- One new generation project has applied for interconnection study since the January update, representing a total of 2 MW
 - The new project is an increase to a wind project currently in the interconnection queue
 - Projected in-service date is in 2010
- Two projects withdrew from the Queue, resulting in a net decrease in new generation projects of 333 MW
- In total, 92 generation projects are currently being tracked by the ISO, totaling approximately 9,743 MW*

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

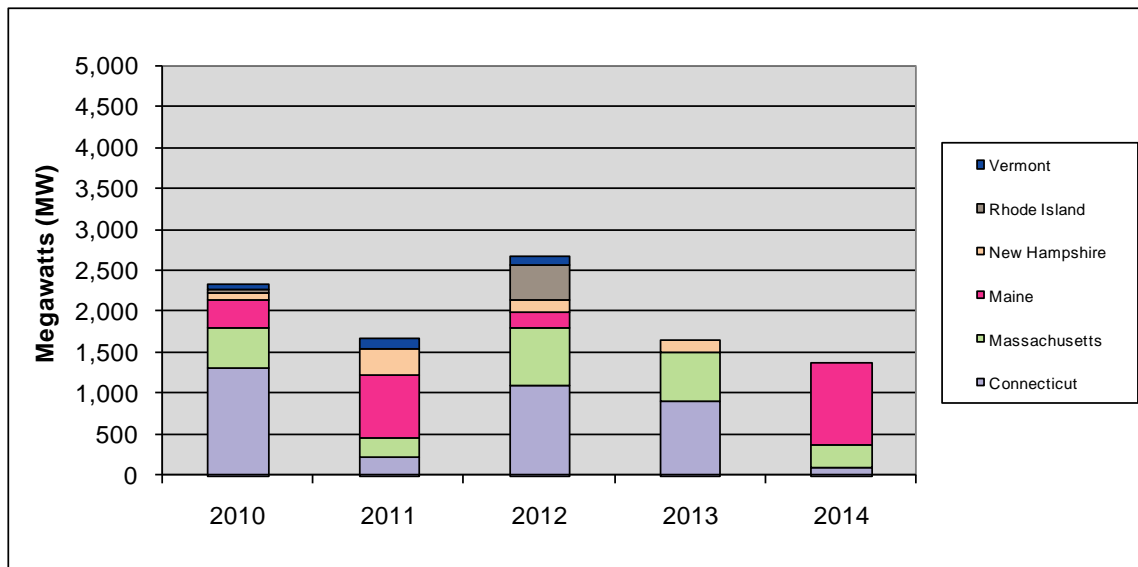
Actual and Projected Annual Capacity Additions By Supply Fuel Type and Demand Resource Type (as of Feb 1, 2010)



	2010	2011	2012	2013	2014	Total	% of Total
Demand Response - Passive	700	278	95	0	0	1,073	8.5
Demand Response - Active	1,579	221	-6	0	0	1,794	14.2
Pumped Storage	0	111	25	25	1,025	1,186	9.4
Wind & Other Renewables	990	1,359	817	210	0	3,376	26.8
Nuclear	0	45	0	0	0	45	0.4
Coal	17	0	36	0	0	53	0.4
Oil	0	13	30	323	0	366	2.9
Natural Gas/Oil	1,278	157	1,273	934	244	3,886	30.8
Natural Gas	67	0	498	159	107	831	6.6
Totals	4,631	2,184	2,768	1,651	1,376	12,610	100.0

•Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources

Actual and Projected Annual Generator Capacity Additions (as of Feb 1, 2010) By State



	2010	2011	2012	2013	2014	Total	% of Total
Vermont	82	140	99	0	0	321	3.3
Rhode Island	34	0	441	0	0	475	4.9
New Hampshire	76	304	130	152	0	662	6.8
Maine	347	770	203	0	1,000	2,320	23.8
Massachusetts	494	244	695	592	269	2,294	23.5
Connecticut	1,319	227	1,111	907	107	3,671	37.7
Totals	2,352	1,685	2,679	1,651	1,376	9,743	100.0

New Generation Projection By Fuel Type (as of Feb 1, 2010)

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	11	380	1	38	10	342
Coal	2	53	0	0	2	53
Hydro	10	1,208	1	8	9	1,200
Landfill Gas	2	36	0	0	2	36
Natural Gas	12	831	1	2	11	829
Natural Gas/Oil	15	3,886	5	1,182	10	2,704
Nuclear Uprates	2	45	0	0	2	45
Oil	3	366	0	0	3	366
Wind	35	2,938	5	206	30	2,732
Total	92	9,743	13	1,436	79	8,307

- 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 (as of Feb 1, 2010)

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	18	523	1	38	17	485
Intermediate	17	3,473	2	628	15	2,845
Peaker	22	2,809	5	564	17	2,245
Wind Turbine	35	2,938	5	206	30	2,732
Total	92	9,743	13	1,436	79	8,307

- 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 (as of Feb 1, 2010)

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	11	380	11	380	0	0	0	0	0	0
Coal	2	53	2	53	0	0	0	0	0	0
Hydro	10	1,208	0	0	6	21	4	1,187	0	0
Landfill Gas	2	36	2	36	0	0	0	0	0	0
Natural Gas	12	831	1	9	4	605	7	217	0	0
Natural Gas/Oil	15	3,886	0	0	7	2,847	8	1,039	0	0
Nuclear Upgrades	2	45	2	45	0	0	0	0	0	0
Oil	3	366	0	0	0	0	3	366	0	0
Wind	35	2,938	0	0	0	0	0	0	35	2,938
Total	92	9,743	18	523	17	3,473	22	2,809	35	2,938

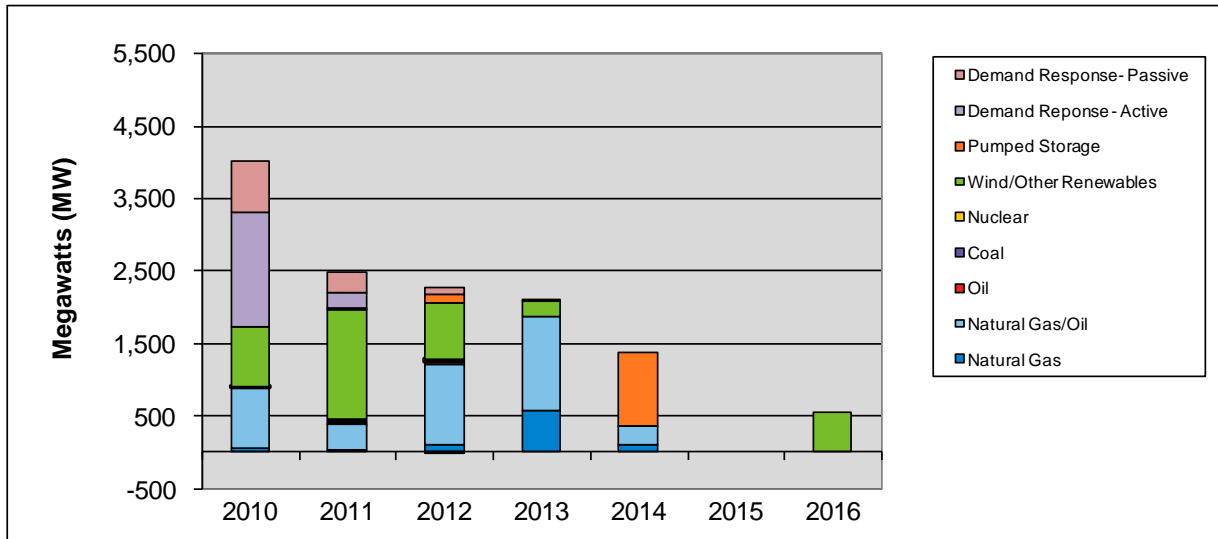
New Generation as of March 1, 2010

New Generation Update (as of March 1, 2010)

- One new generation project has applied for interconnection study since the February update, representing a total of 550 MW
 - The new project is a wind project
 - Projected in service in 2016
- Two projects withdrew from the Queue, resulting in a net increase in new generation projects of 143 MW
- In total, 92 generation projects are currently being tracked by the ISO, totaling approximately 9,880 MW*

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

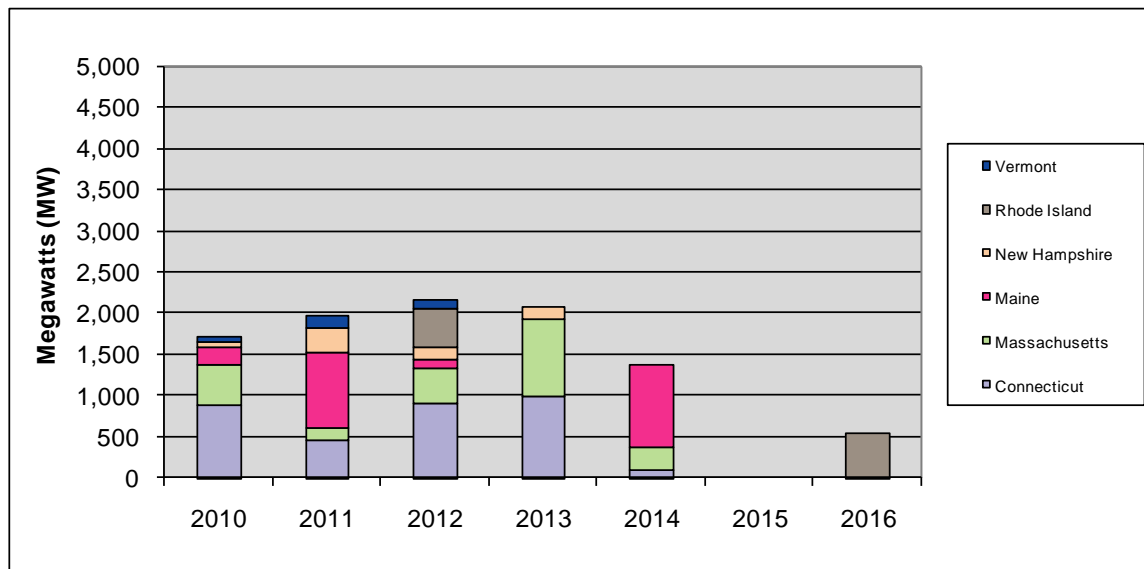
Actual and Projected Annual Capacity Additions By Supply Fuel Type and Demand Resource Type (as of March 1, 2010)



	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Demand Response - Passive	700	278	95	0	0	0	0	1,073	8.4
Demand Response - Active	1,579	221	-6	0	0	0	0	1,794	14.1
Pumped Storage	0	25	111	25	1,025	0	0	1,186	9.3
Wind & Other Renewables	824	1,499	774	210	0	0	550	3,857	30.3
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	0.3
Natural Gas/Oil	838	372	1,124	1,287	244	0	0	3,865	30.3
Natural Gas	48	19	87	570	107	0	0	831	6.5
Totals	4,006	2,472	2,251	2,092	1,376	0	550	12,747	100.0

•Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources

Actual and Projected Annual Generator Capacity Additions (as of March 1, 2010) By State



	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Vermont	61	140	99	0	0	0	0	300	3.0
Rhode Island	0	0	475	0	0	0	550	1,025	10.4
New Hampshire	76	312	138	152	0	0	0	678	6.9
Maine	217	900	118	0	1,000	0	0	2,235	22.6
Massachusetts	492	160	428	945	269	0	0	2,294	23.2
Connecticut	881	461	904	995	107	0	0	3,348	33.9
Totals	1,727	1,973	2,162	2,092	1,376	0	550	9,880	100.0

New Generation Projection By Fuel Type (as of March 1, 2010)

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	11	380	1	38	10	342
Coal	2	53	0	0	2	53
Hydro	9	1,224	0	24	9	1,200
Landfill Gas	2	36	0	0	2	36
Natural Gas	12	831	1	2	11	829
Natural Gas/Oil	15	3,865	5	1,161	10	2,704
Nuclear Upgrades	2	45	0	0	2	45
Oil	2	43	0	0	2	43
Wind	35	3,403	5	206	30	3,197
Total	90	9,880	12	1,431	78	8,449

- 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 (as of March 1, 2010)

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	18	523	1	38	17	485
Intermediate	16	3,489	1	644	15	2,845
Peaker	21	2,465	5	543	16	1,922
Wind Turbine	35	3,403	5	206	30	3,197
Total	90	9,880	12	1,431	78	8,449

- 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 (as of March 1, 2010)

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	11	380	11	380	0	0	0	0	0	0
Coal	2	53	2	53	0	0	0	0	0	0
Hydro	9	1,224	0	0	5	37	4	1,187	0	0
Landfill Gas	2	36	2	36	0	0	0	0	0	0
Natural Gas	12	831	1	9	4	605	7	217	0	0
Natural Gas/Oil	15	3,865	0	0	7	2,847	8	1,018	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
Wind	35	3,403	0	0	0	0	0	0	35	3,403
Total	90	9,880	18	523	16	3,489	21	2,465	35	3,403

Reliability Costs

Net Commitment Period Compensation (NCPC) Operating Costs

What are Daily NCPC Payments?

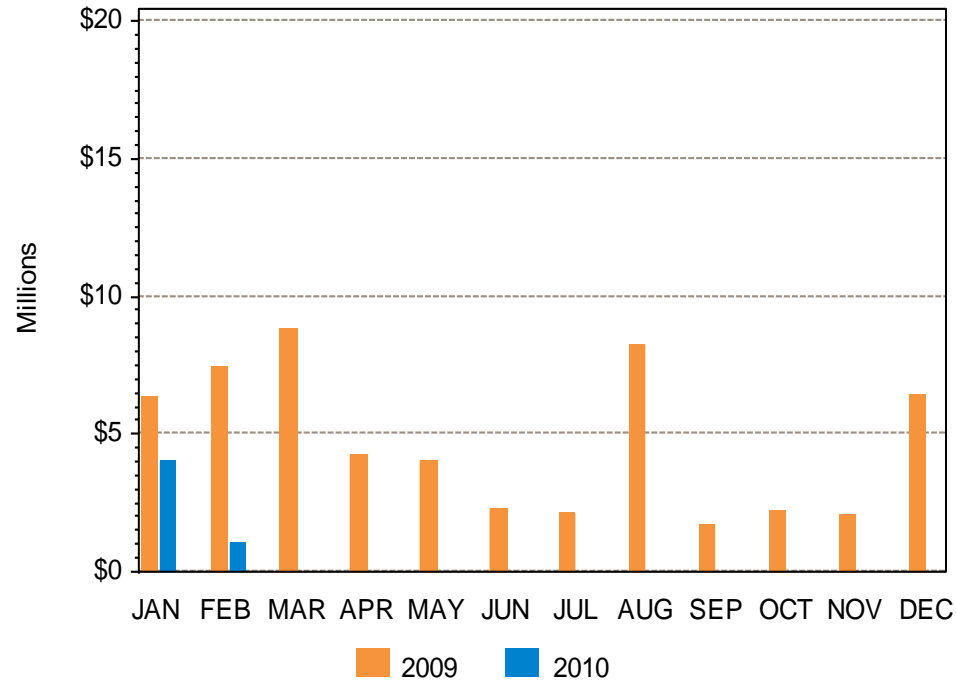
- “Make-whole” payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource’s offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day
- Typically, this is the result of some out-of-merit 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

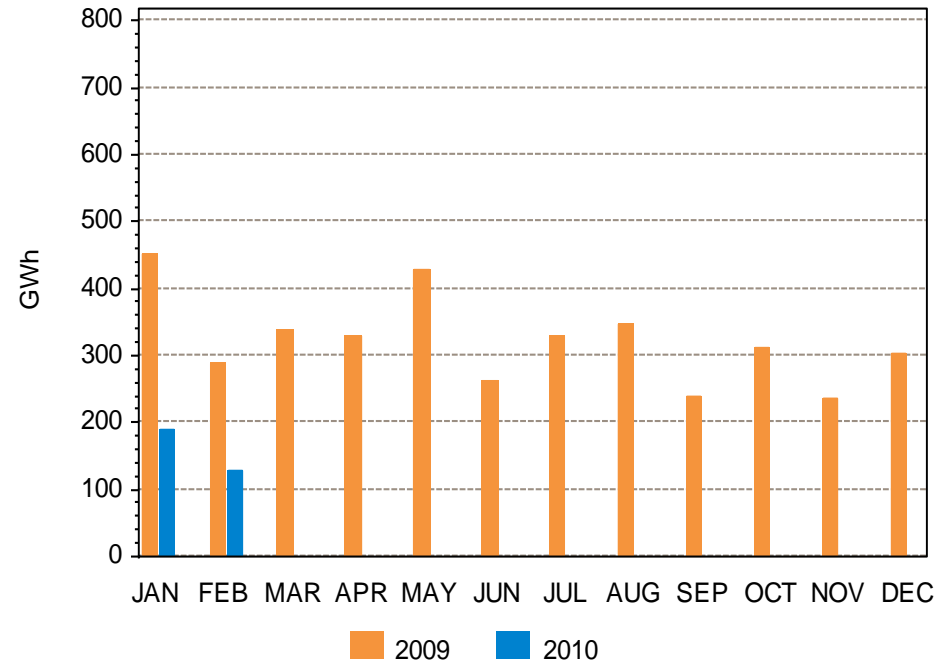
Voltage NCPC Payments	Reliability costs paid to resources operated by the ISO-NE to provide voltage control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (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

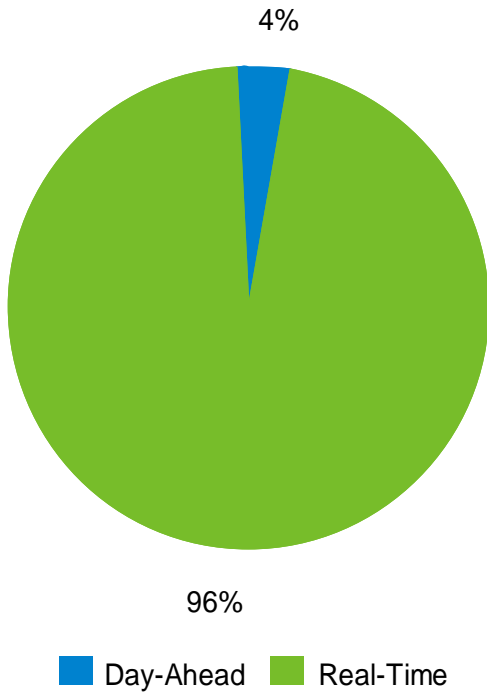


Note:

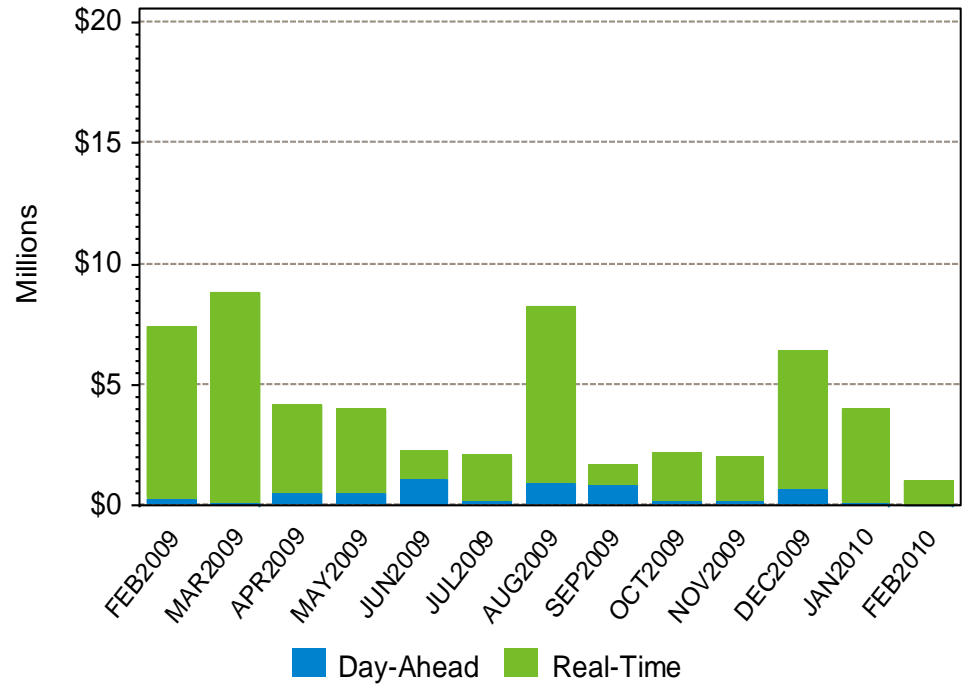
- Overall Reliability Cost MWh includes out of merit DA and RT 1st Contingency, 2nd Contingency, Voltage, and RT Distribution components.
- Energy includes daily totals of cleared DA energy and RT energy from resources receiving NCPC payments.

DA and RT NCPC Payments

FEB-10 Total = \$1.03 M

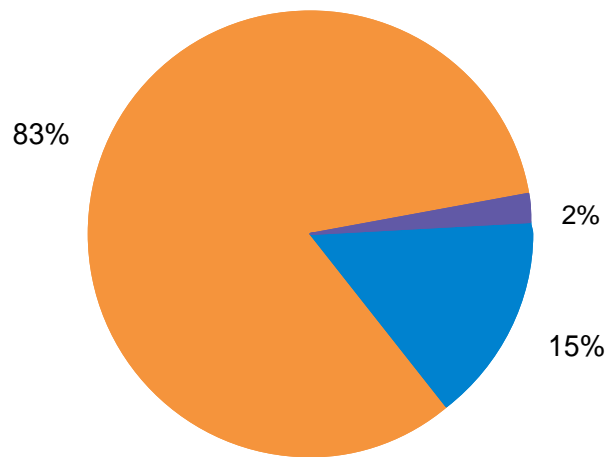


Last 13 Months



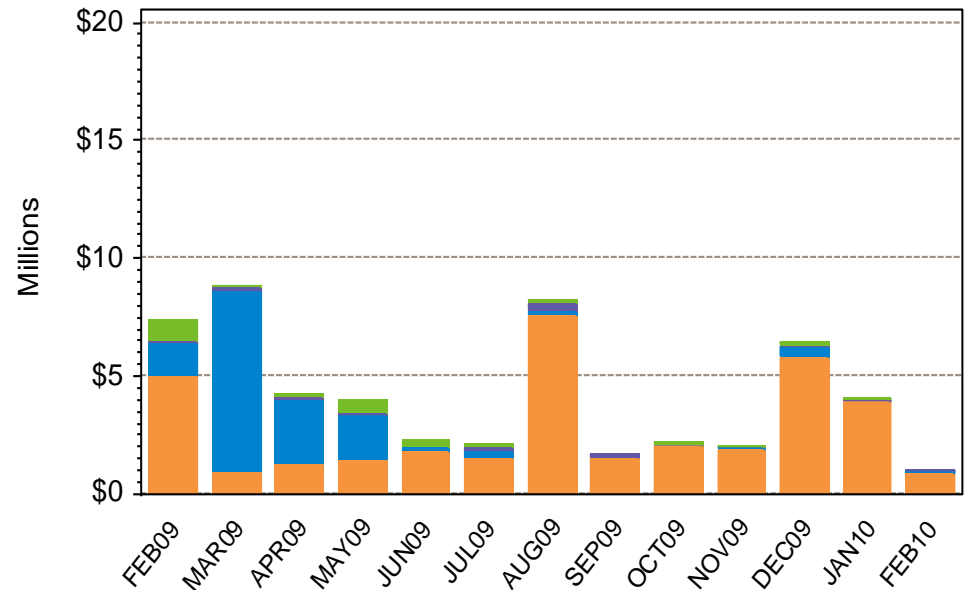
NCPC Payments by Type

FEB-10 Total = \$1.03 M



■ 1st C ■ 2nd C
■ Distrib

Last 13 Months

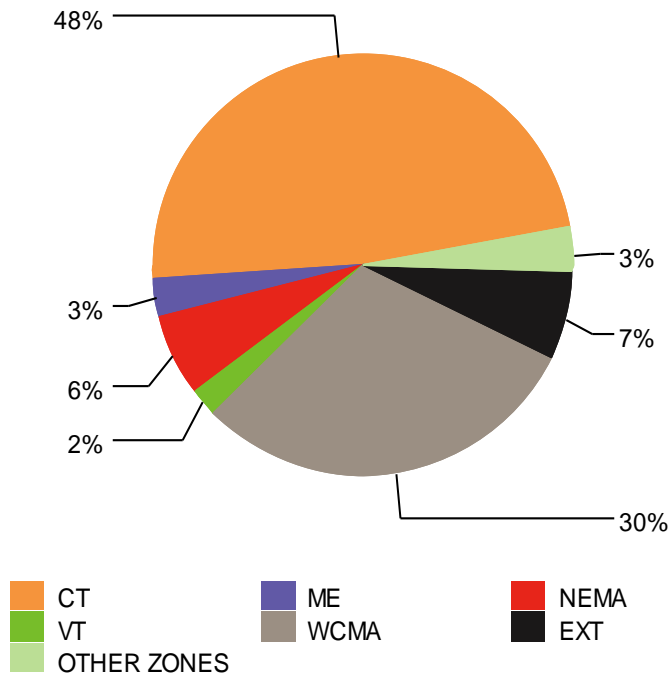


■ 1st C ■ 2nd C
■ Voltage ■ Distrib

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

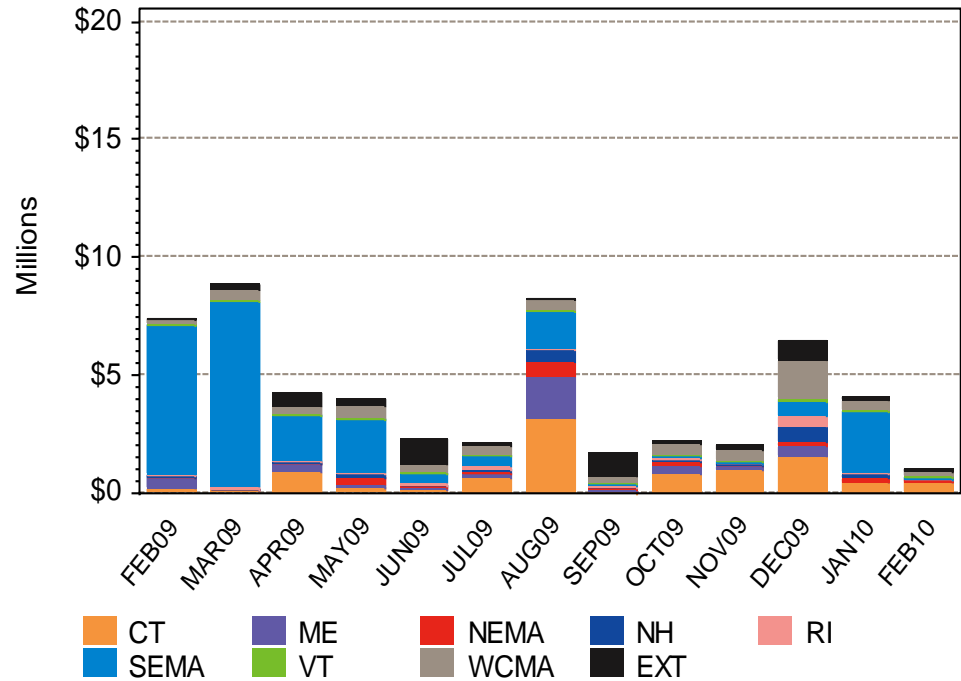
NCPC Payments by Location

FEB-10 Total = \$1.03 M



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

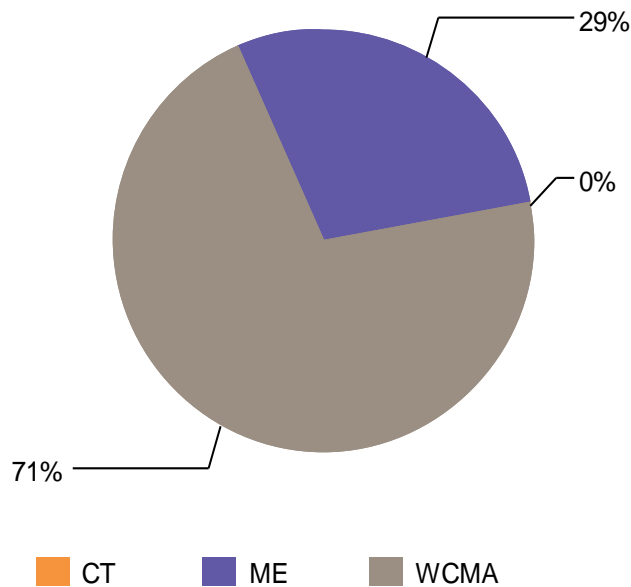
Last 13 Months



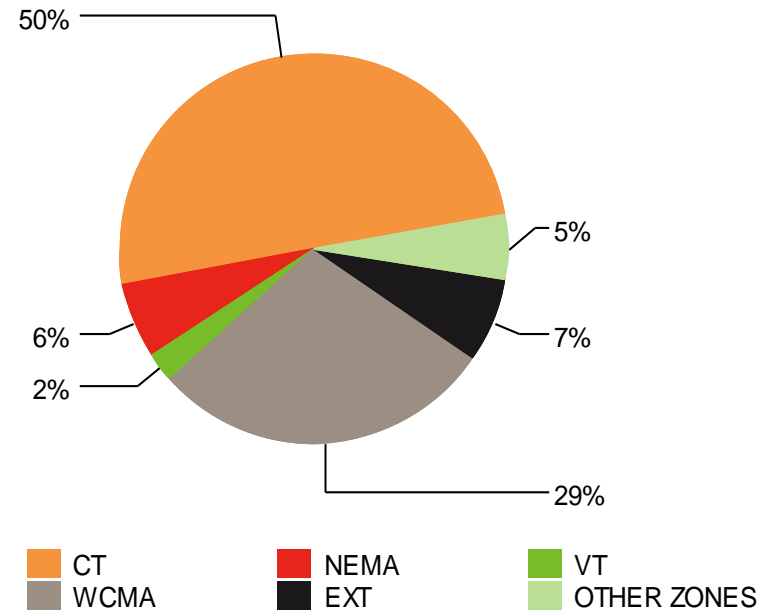
VT – Vermont Region
 SEMA – Southeast Massachusetts Region
 WCMA – Western/Central Massachusetts Region
 NEMA – Northeast Massachusetts Region
 EXT – External Locations

DA and RT NCPC Payments by Location

FEB-10 Day-Ahead Total = \$0.03 M

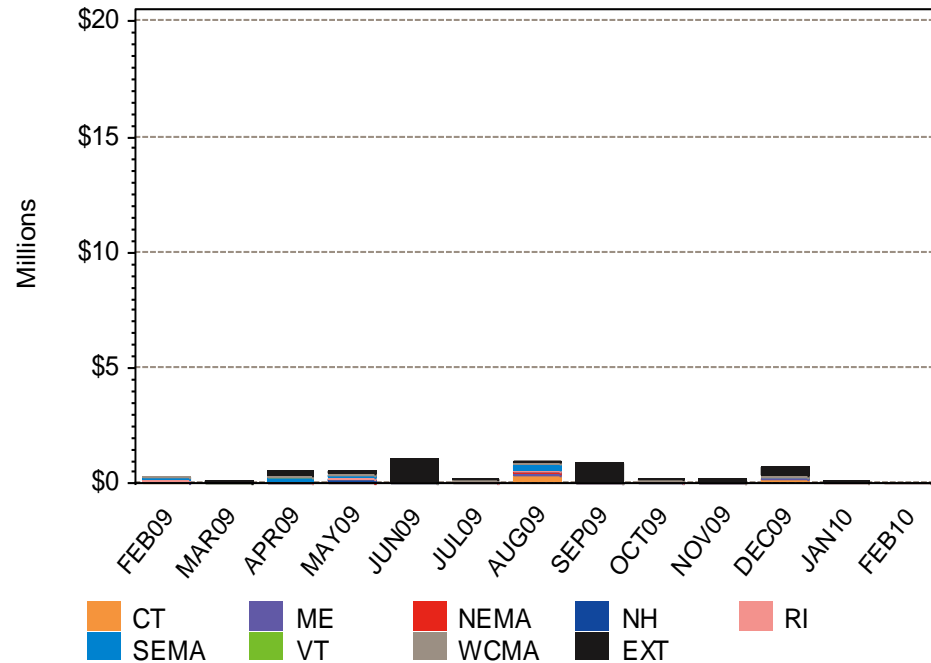


FEB-10 Real-Time Total = \$1.00 M

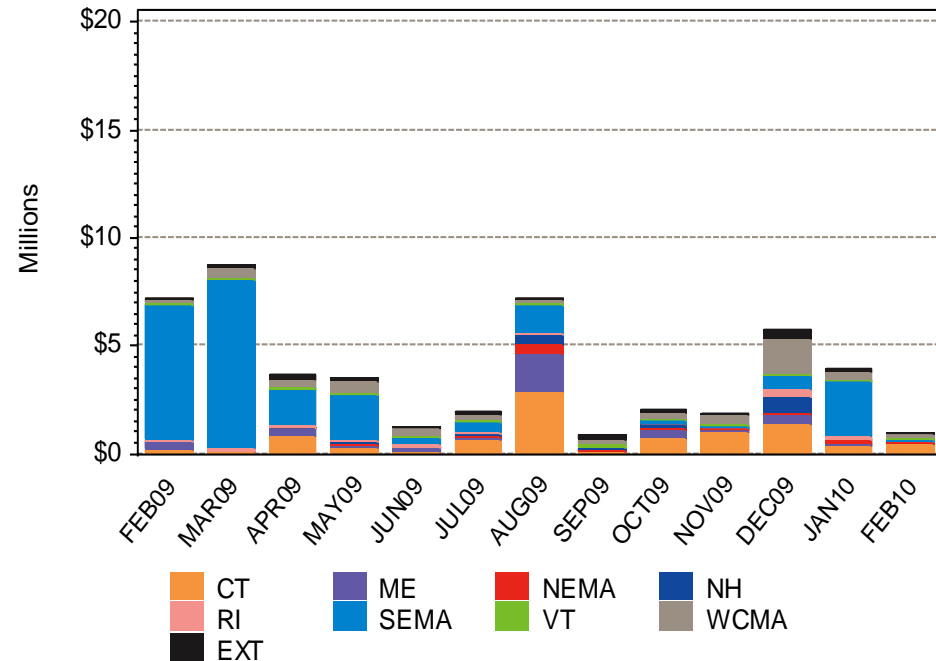


DA and RT NCPC Payments by Location, Last 13 Months

Day-Ahead, Last 13 Months

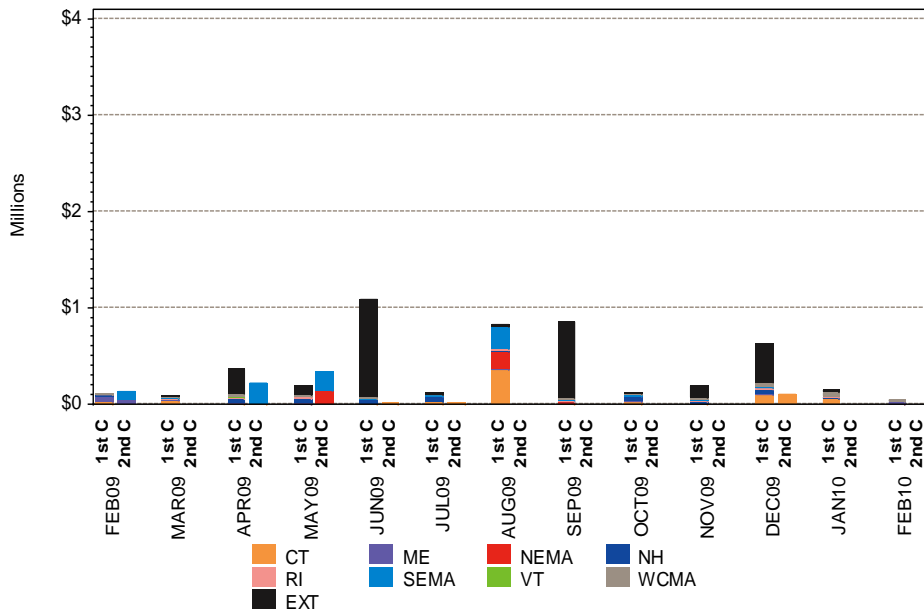


Real-Time, Last 13 Months

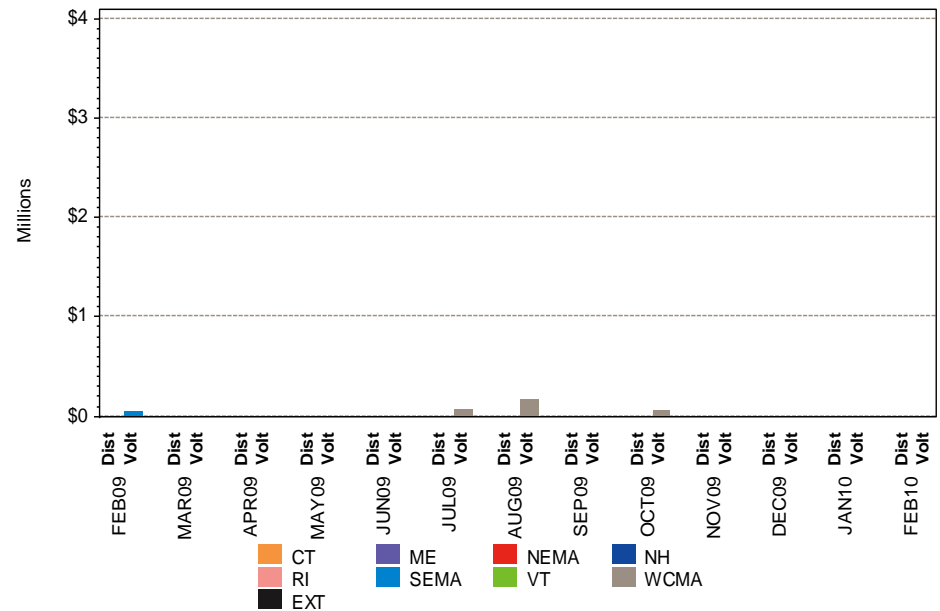


DA NCPC Payments by Type and Location

First and Second Contingency Payments

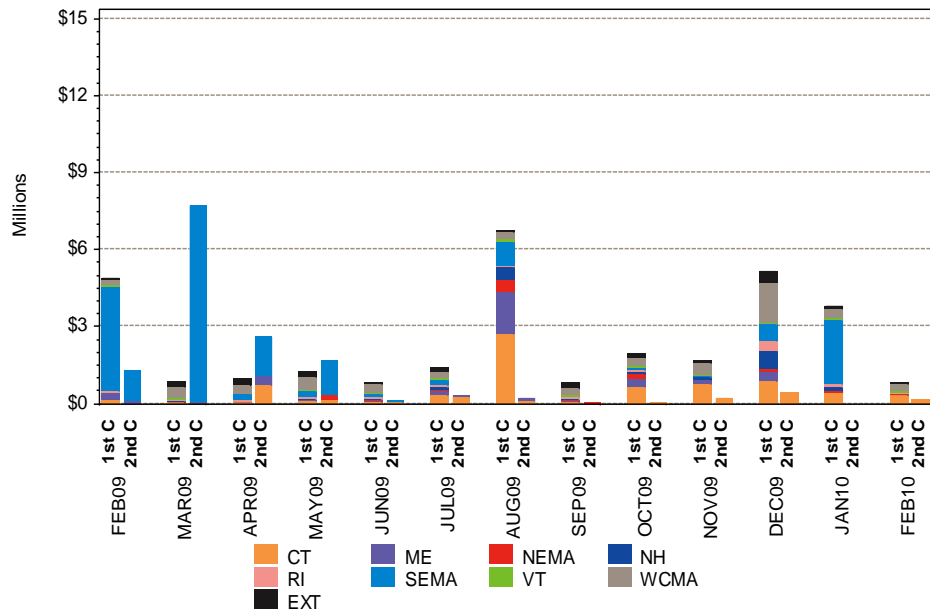


Voltage and Distribution Payments

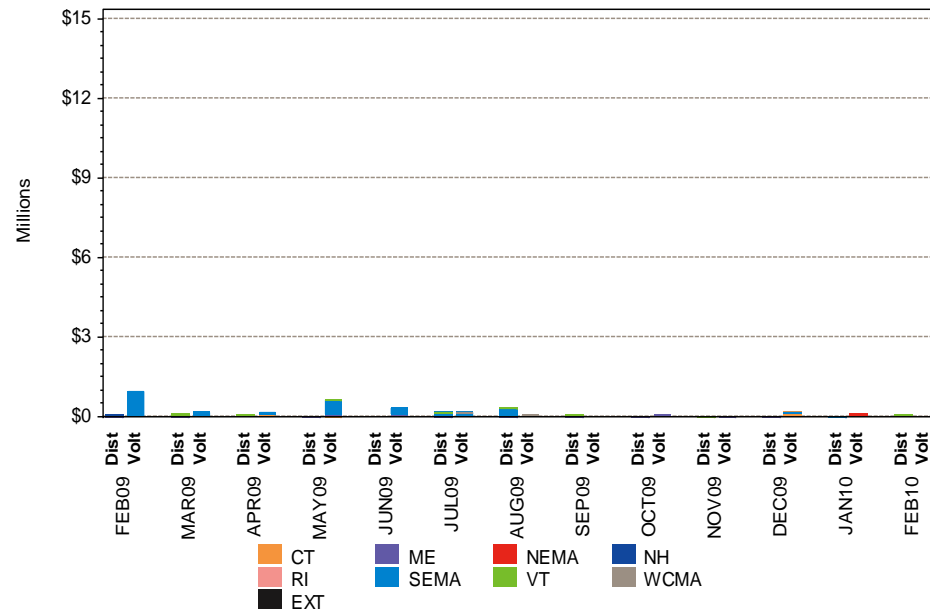


RT NCPC Payments by Type and Location

First and Second Contingency Payments

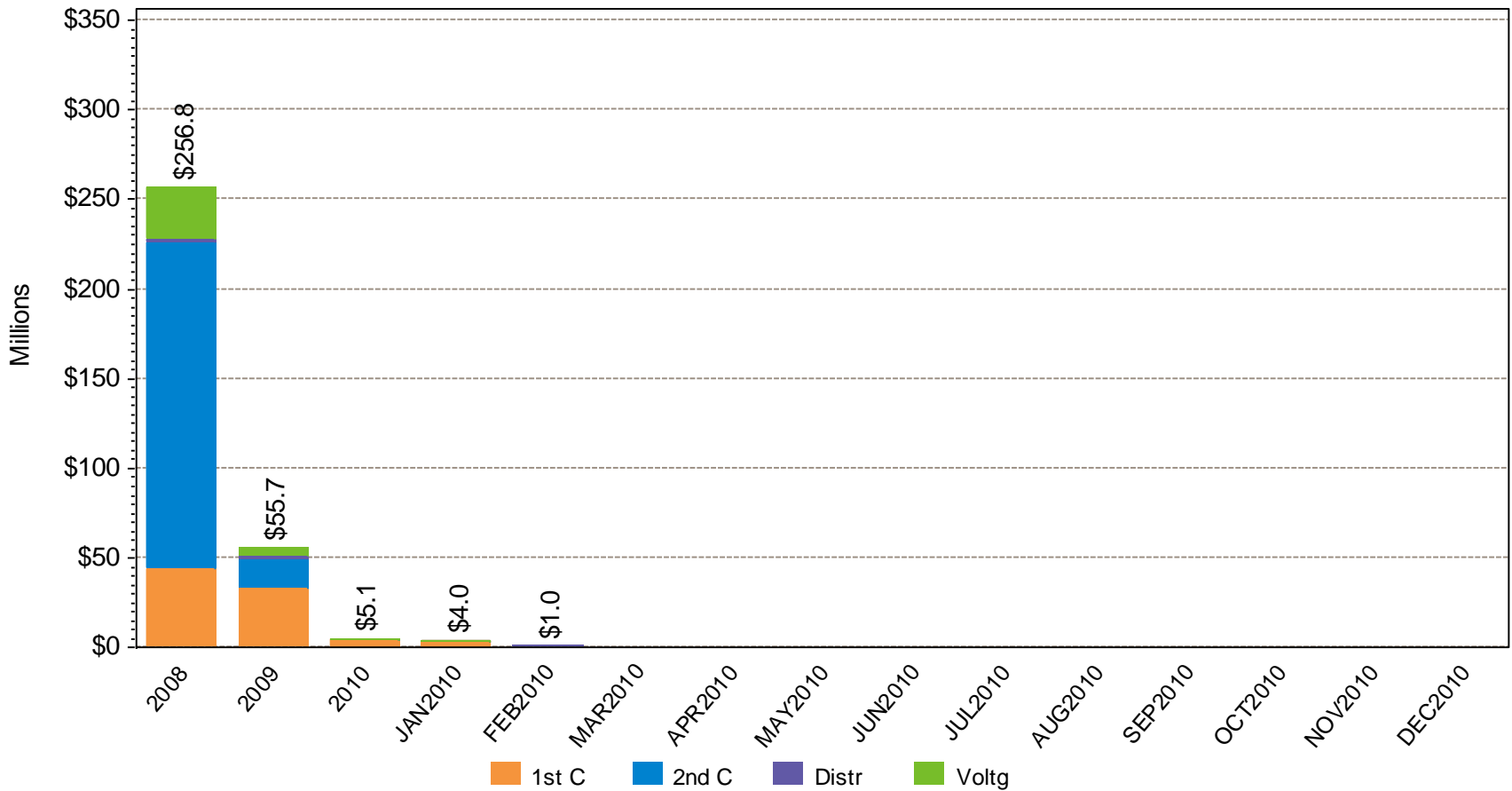


Voltage and Distribution Payments



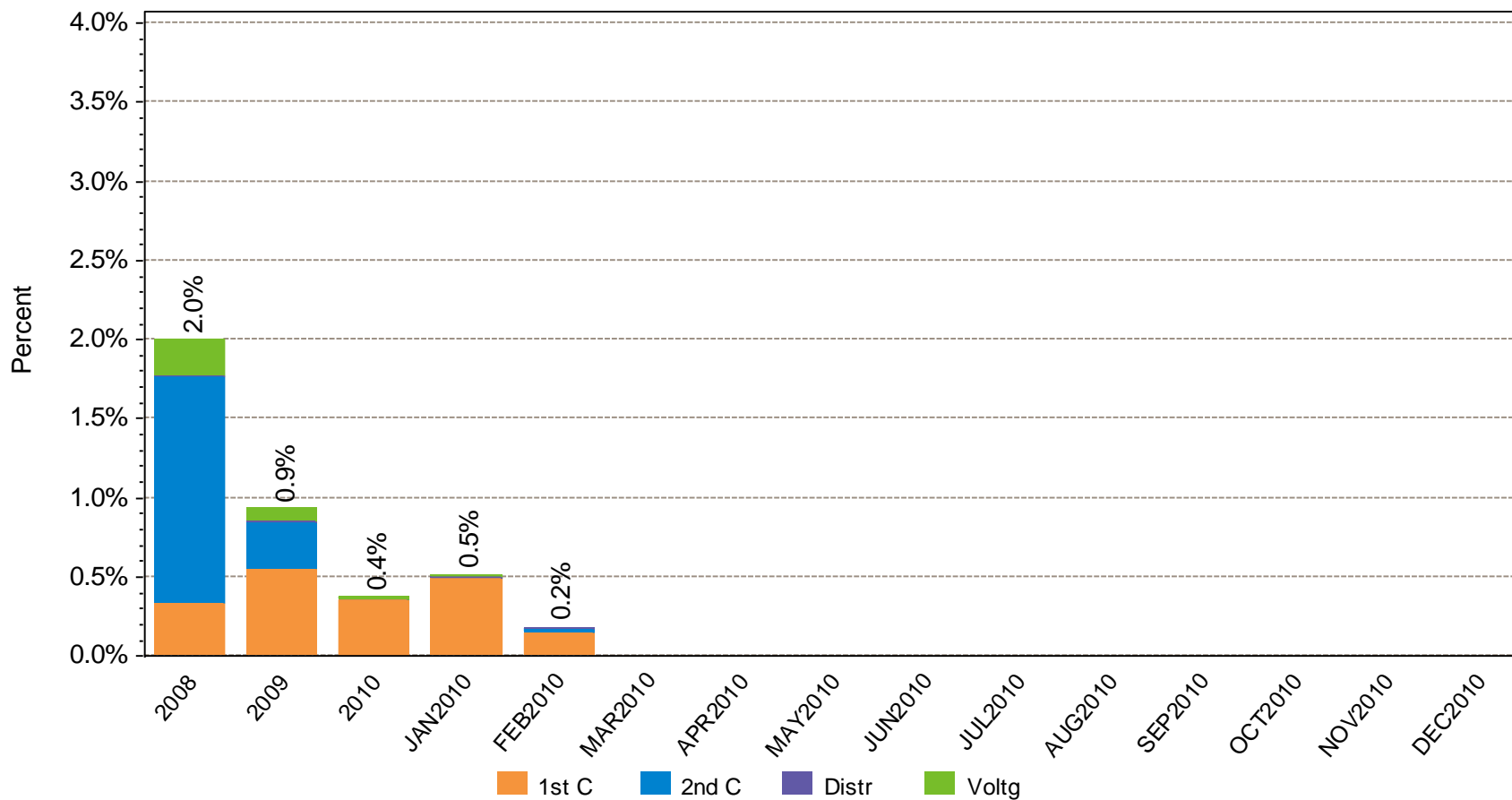
NCPC Payments by Type

Payments by Type of NCPC



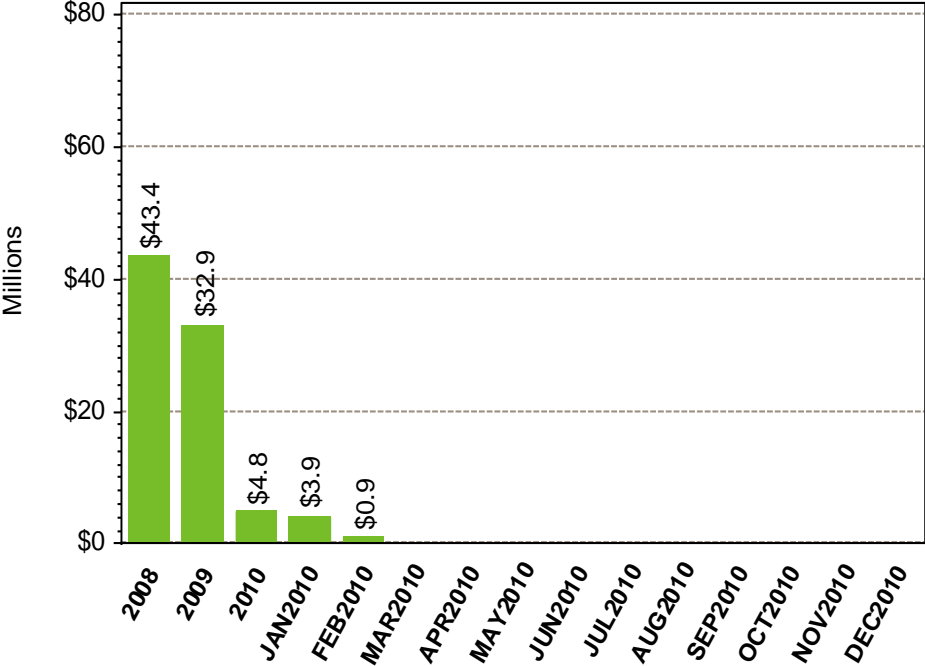
NCPC Payments by Percent of Energy Market

NCPC By Type as Percent of Energy Market

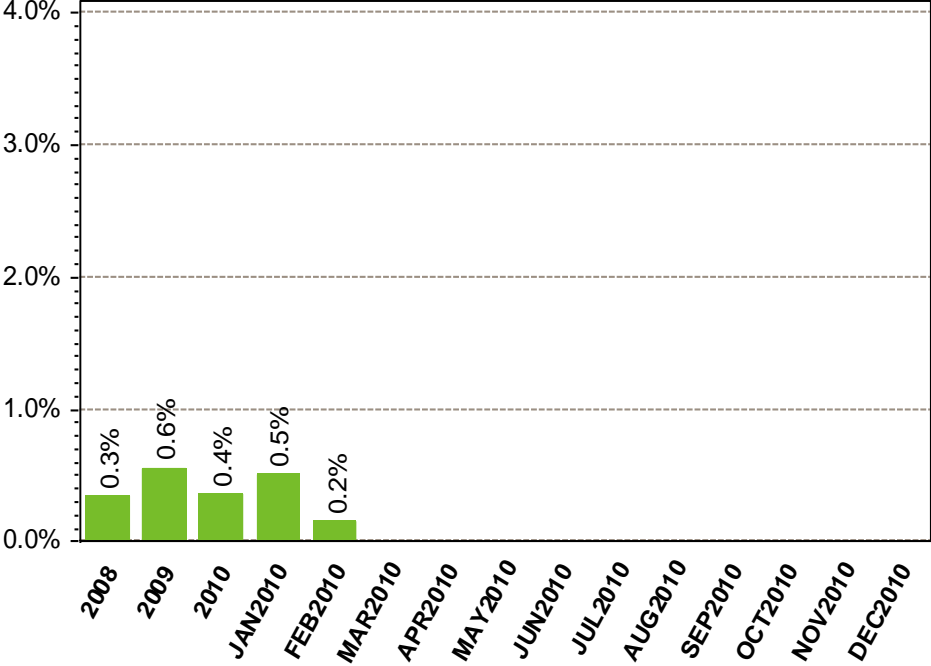


First Contingency NCPC Payments

Value of Payments



% of Energy Market Value

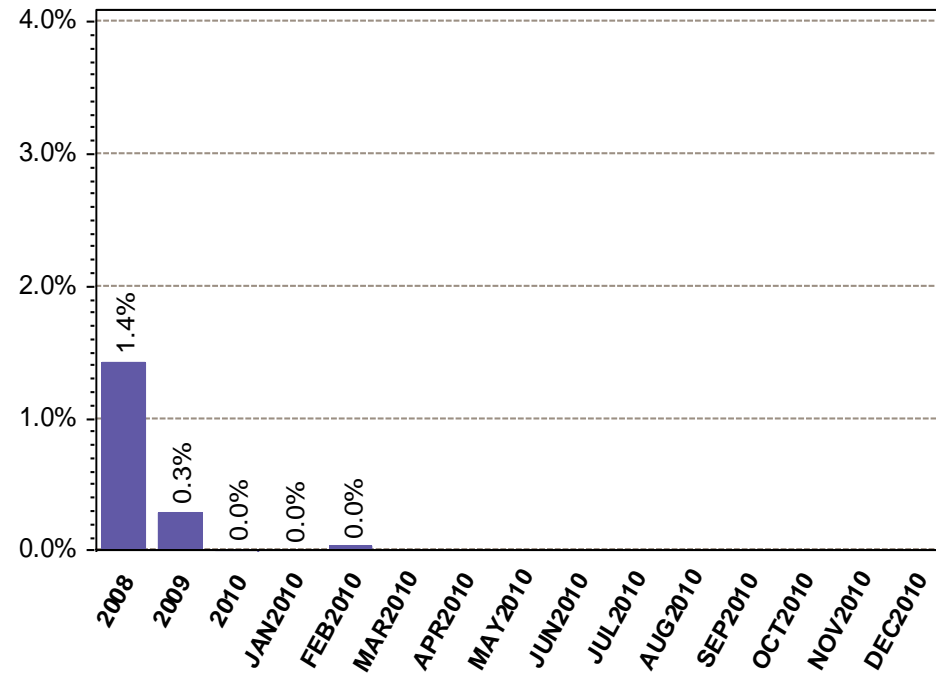
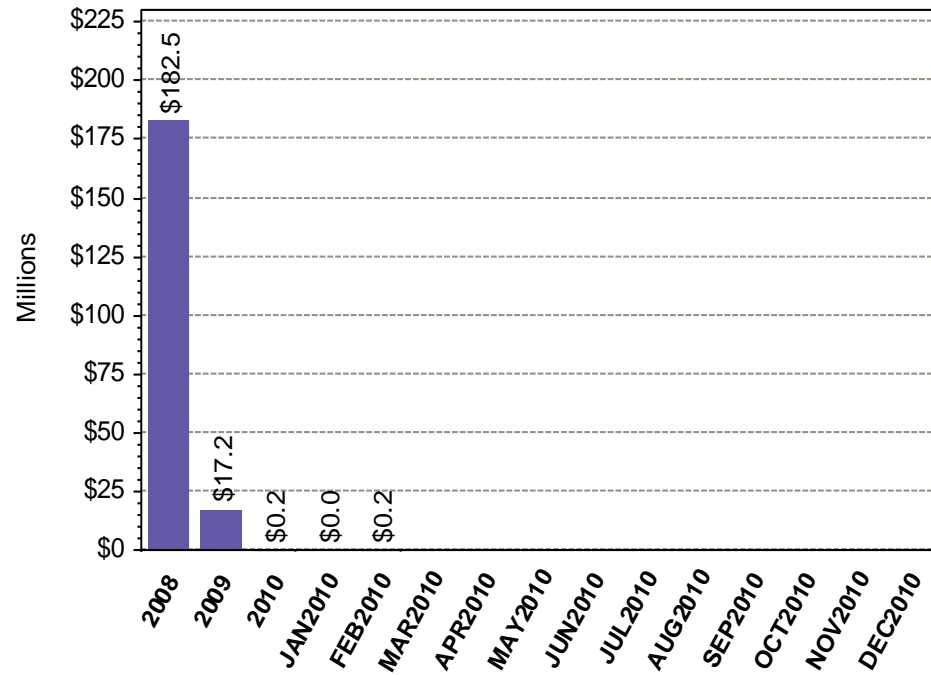


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Second Contingency NCPC Payments

Value of Payments

% of Energy Market Value

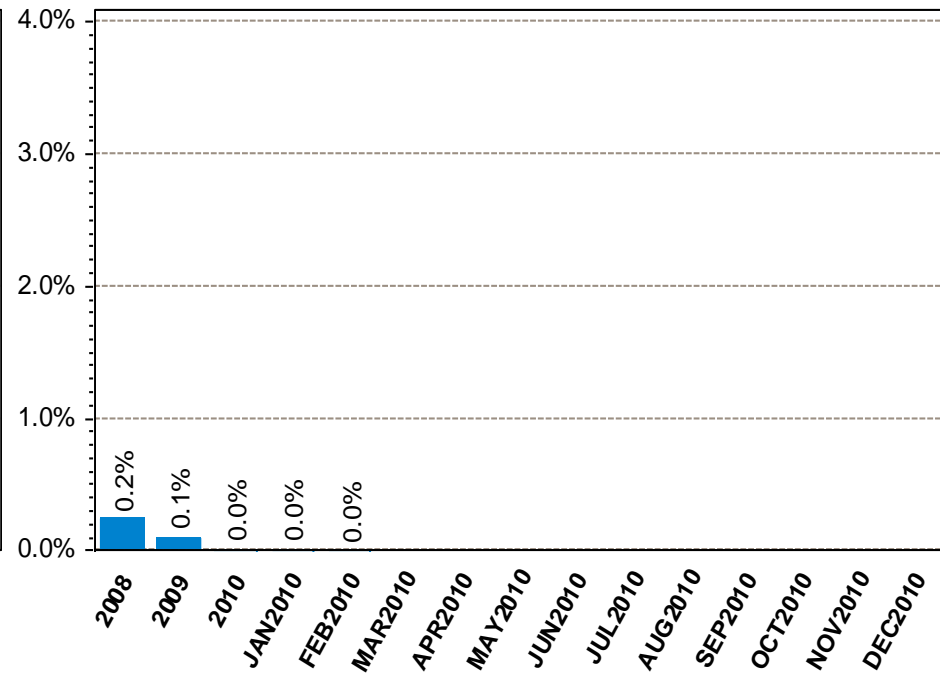
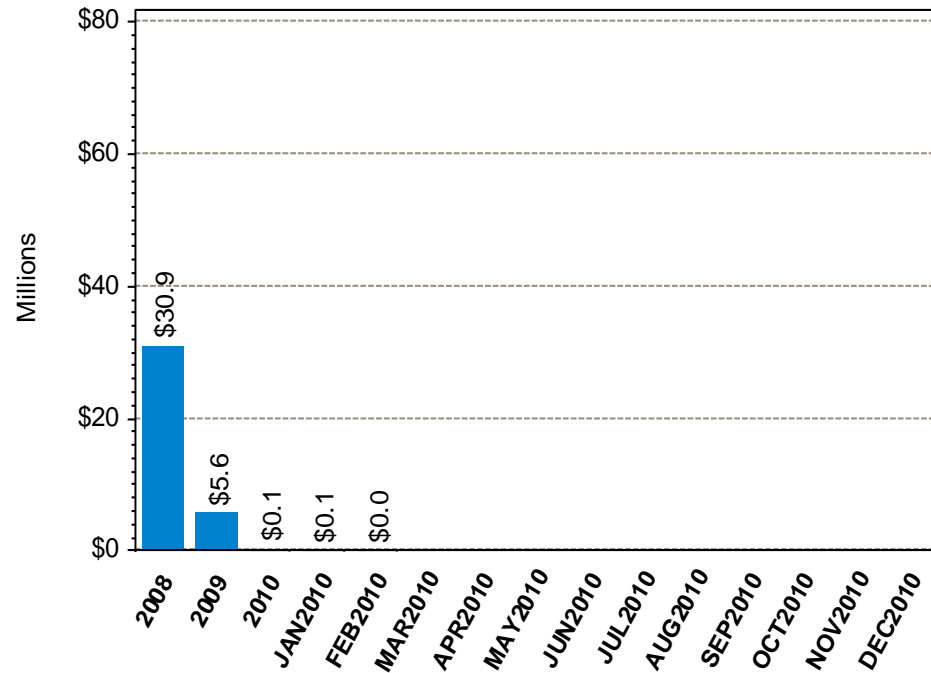


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

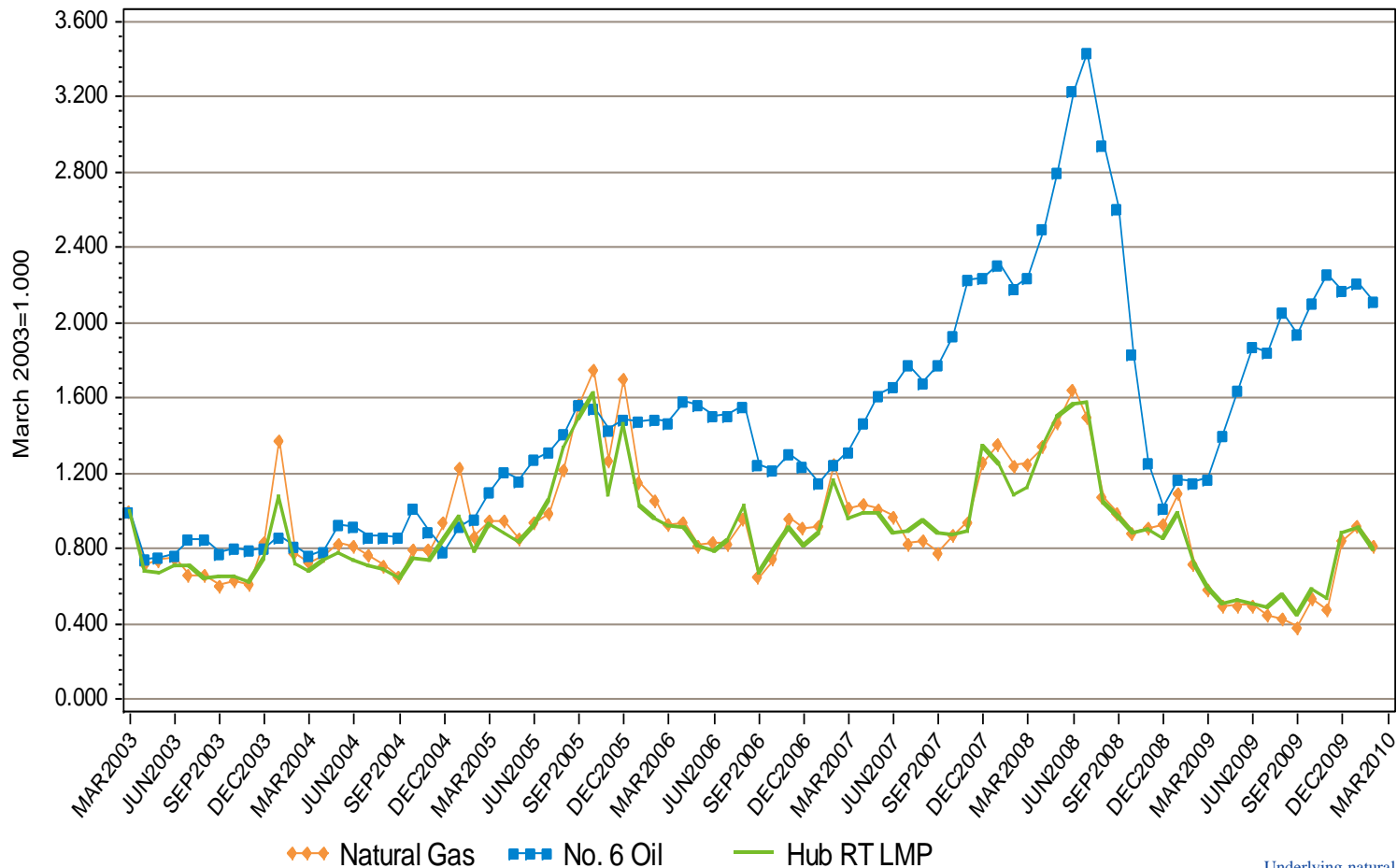
The following slides outline

- 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%
February-09	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$49.06	\$50.06	\$47.67	\$48.61	\$49.48	\$48.93	\$50.64	\$49.73	\$49.38
Real-Time	\$49.14	\$50.26	\$47.37	\$48.72	\$49.60	\$49.09	\$49.98	\$49.86	\$49.51
RT Delta %	0.2%	0.4%	-0.6%	0.2%	0.2%	0.3%	-1.3%	0.3%	0.3%
February-10	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$53.54	\$55.27	\$51.29	\$53.02	\$54.04	\$53.60	\$53.89	\$54.41	\$53.93
Real-Time	\$54.19	\$56.21	\$52.01	\$53.70	\$54.77	\$54.15	\$54.54	\$54.98	\$54.60
RT Delta %	1.2%	1.7%	1.4%	1.3%	1.4%	1.0%	1.2%	1.0%	1.2%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	9.1%	10.4%	7.6%	9.1%	9.2%	9.5%	6.4%	9.4%	9.2%
Yr over Yr RT	10.3%	11.8%	9.8%	10.2%	10.4%	10.3%	9.1%	10.3%	10.3%

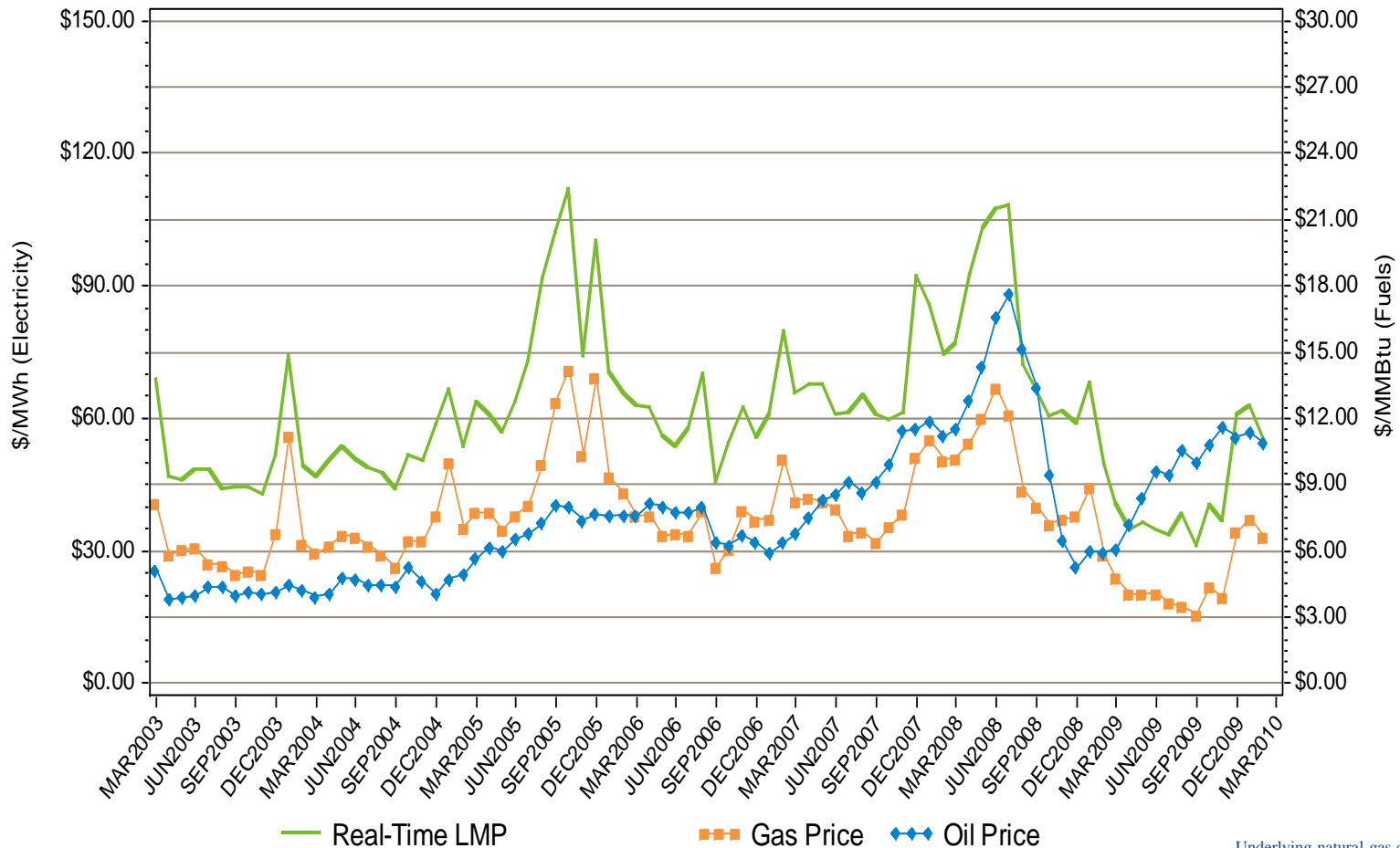
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:



Monthly Average Fuel Price and RT Hub LMP



Underlying natural gas data furnished by:



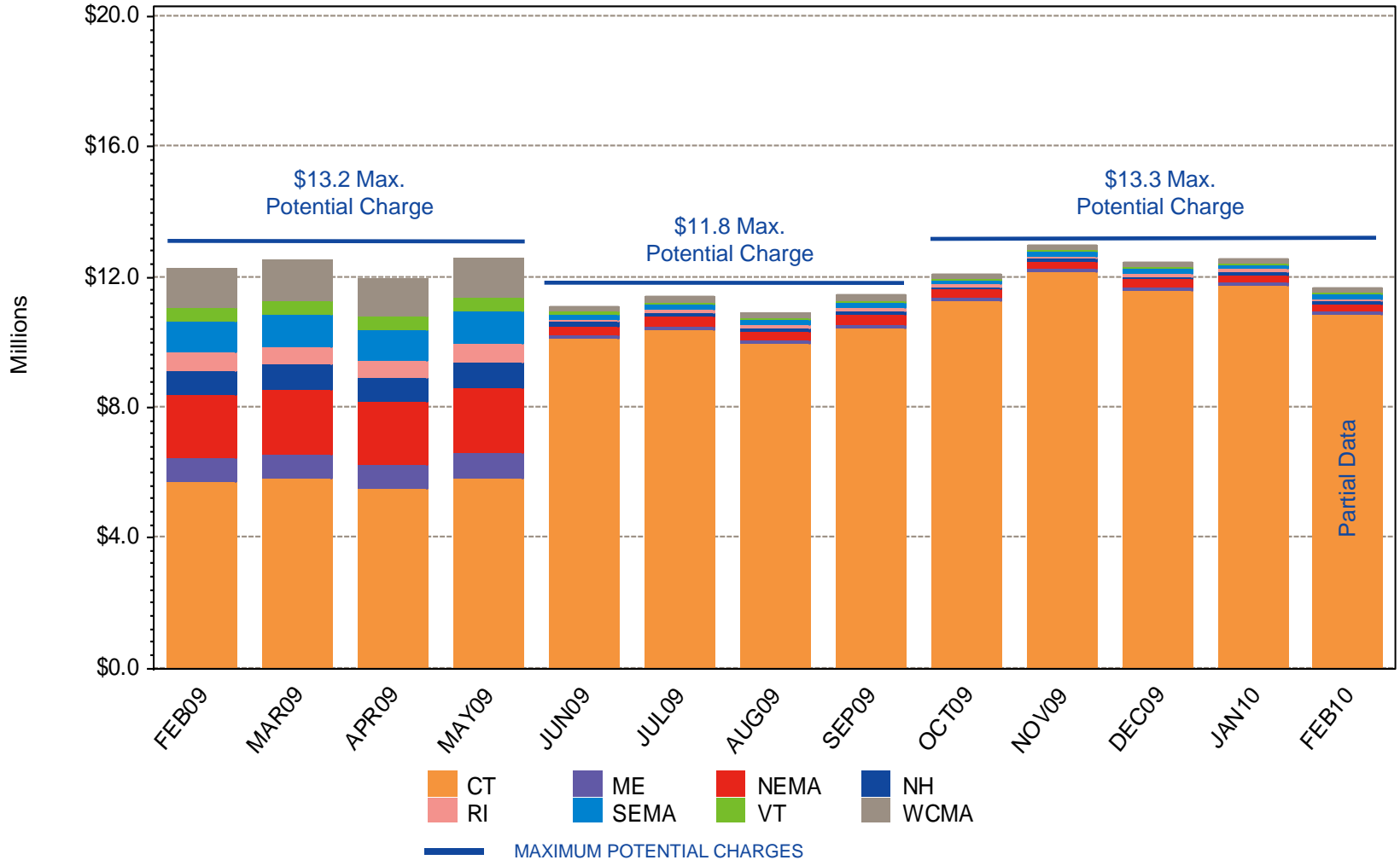
Reserve Market Results – February 2010

- Maximum potential Forward Reserve Market payments of \$11.9M were reduced by credit reductions of \$116K, failure-to-reserve penalties of \$174K and failure-to-activate penalties of \$0M, resulting in a net payout of \$11.7M or 97% of maximum
 - Rest of System: \$1.43M/\$1.52M (94%)
 - Southwest Connecticut: \$3.69M/\$3.8M (97%)
 - Connecticut: \$6.53M/\$6.63M (99%)
 - NEMA/Boston: n/a
- \$1.04M total Real-Time credits were reduced by \$85K in Forward Reserve Energy Obligation Charges for a net of \$949K in Real-Time Reserve payments
 - Rest of System: 60 hours, \$717K
 - Southwest Connecticut: 66 hours, \$33K
 - Connecticut: 66 hours, \$120K
 - NEMA: 60 hours, \$80K
- The system reserve bias factor was not used during February

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

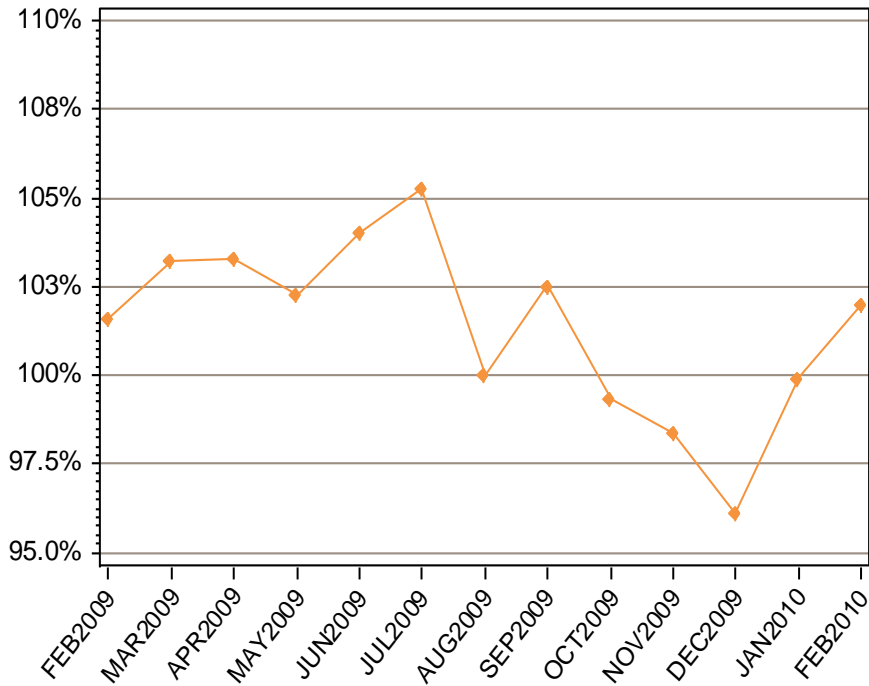
LFRM Charges to Load by Load Zone (\$)

LFRM Charges by Zone, Last 13 Months

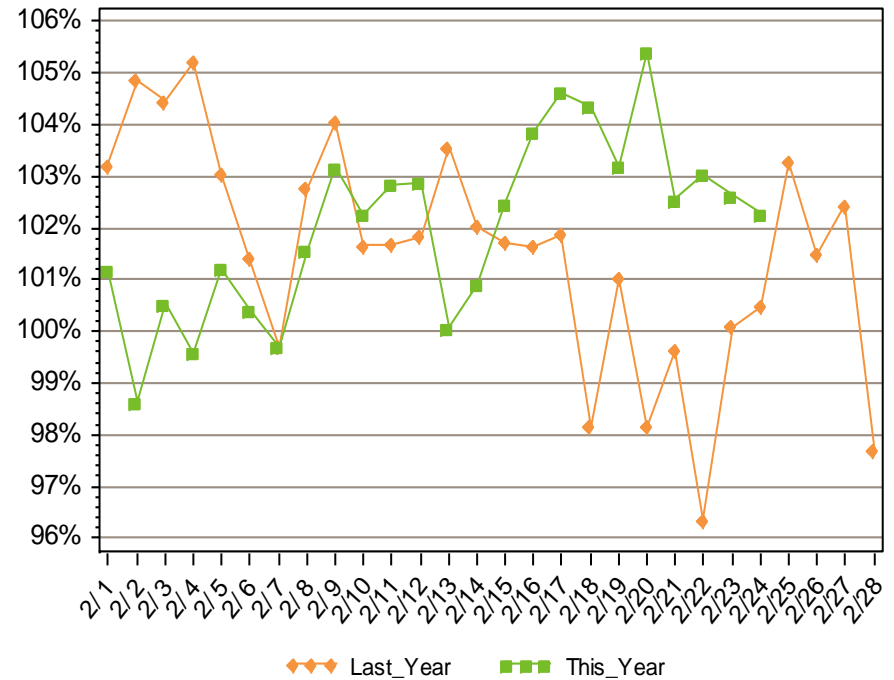


DA Load Obligation Percent of RT Load Obligation

Monthly, Last 13 Months

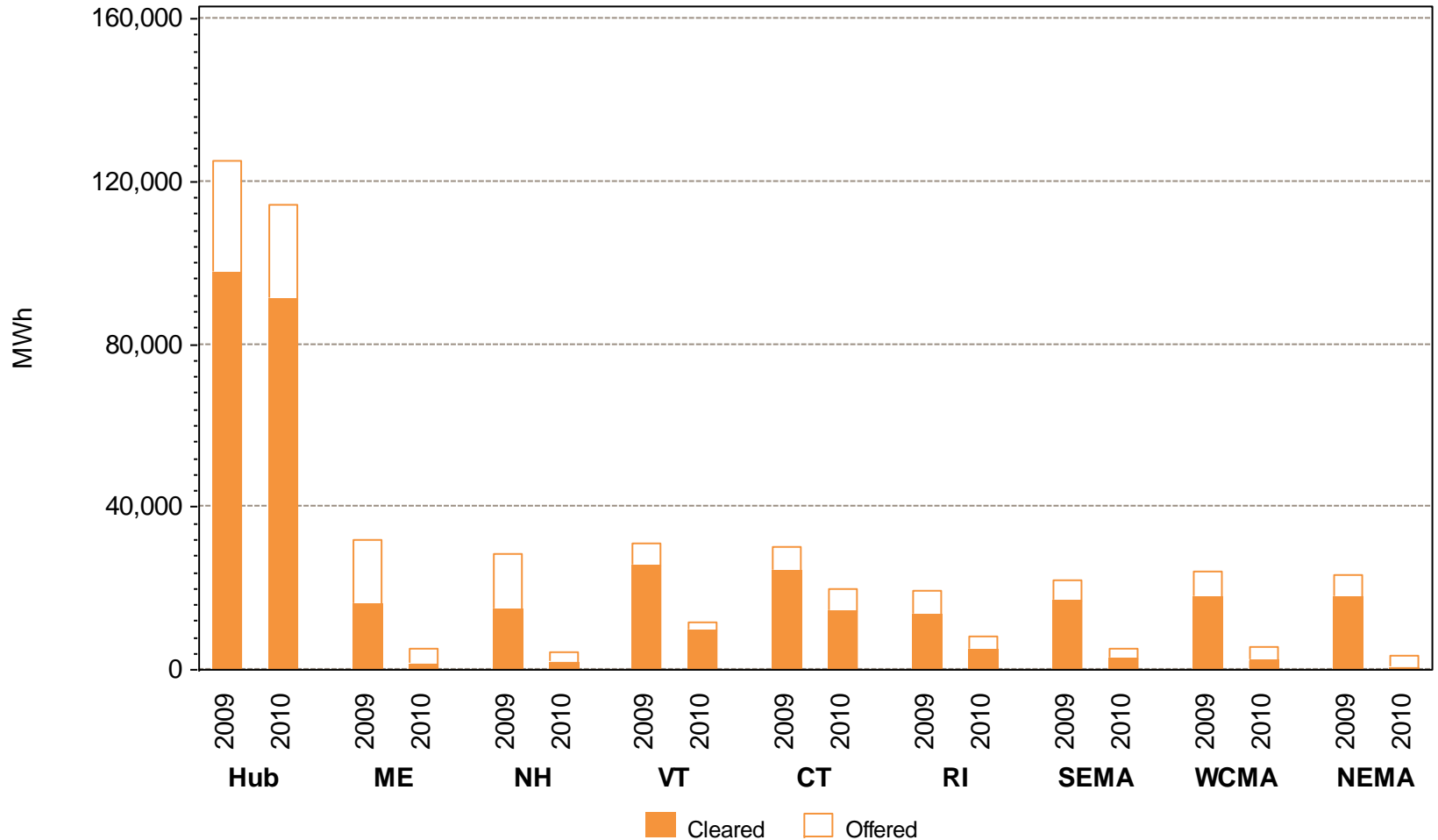


Daily, This Year vs. Last Year



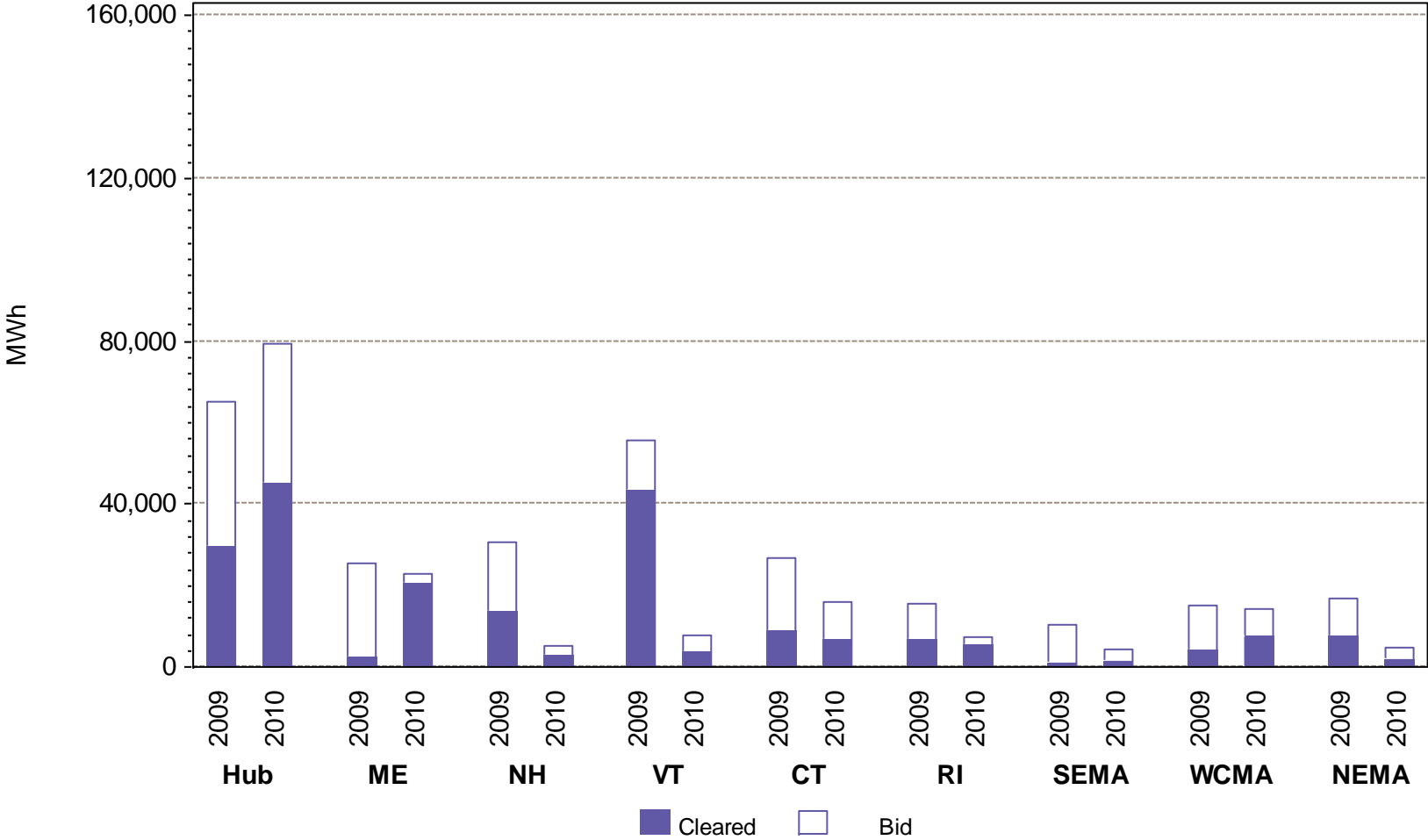
Zonal Increment Offers and Cleared Amounts

February Monthly Totals by Zone



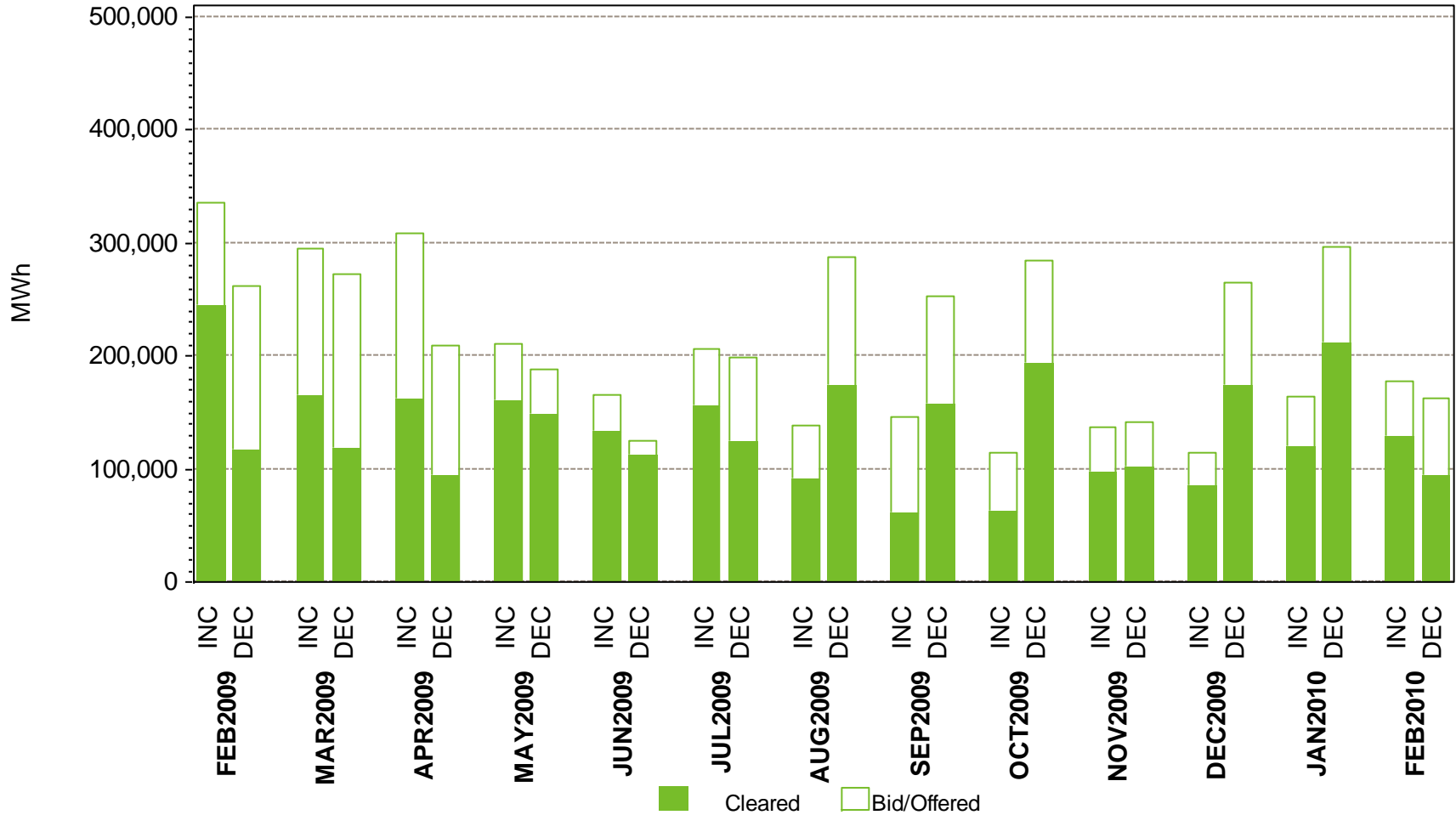
Zonal Decrement Bids and Cleared Amounts

February Monthly Totals by Zone



Total Increment Offers and Decrement Bids

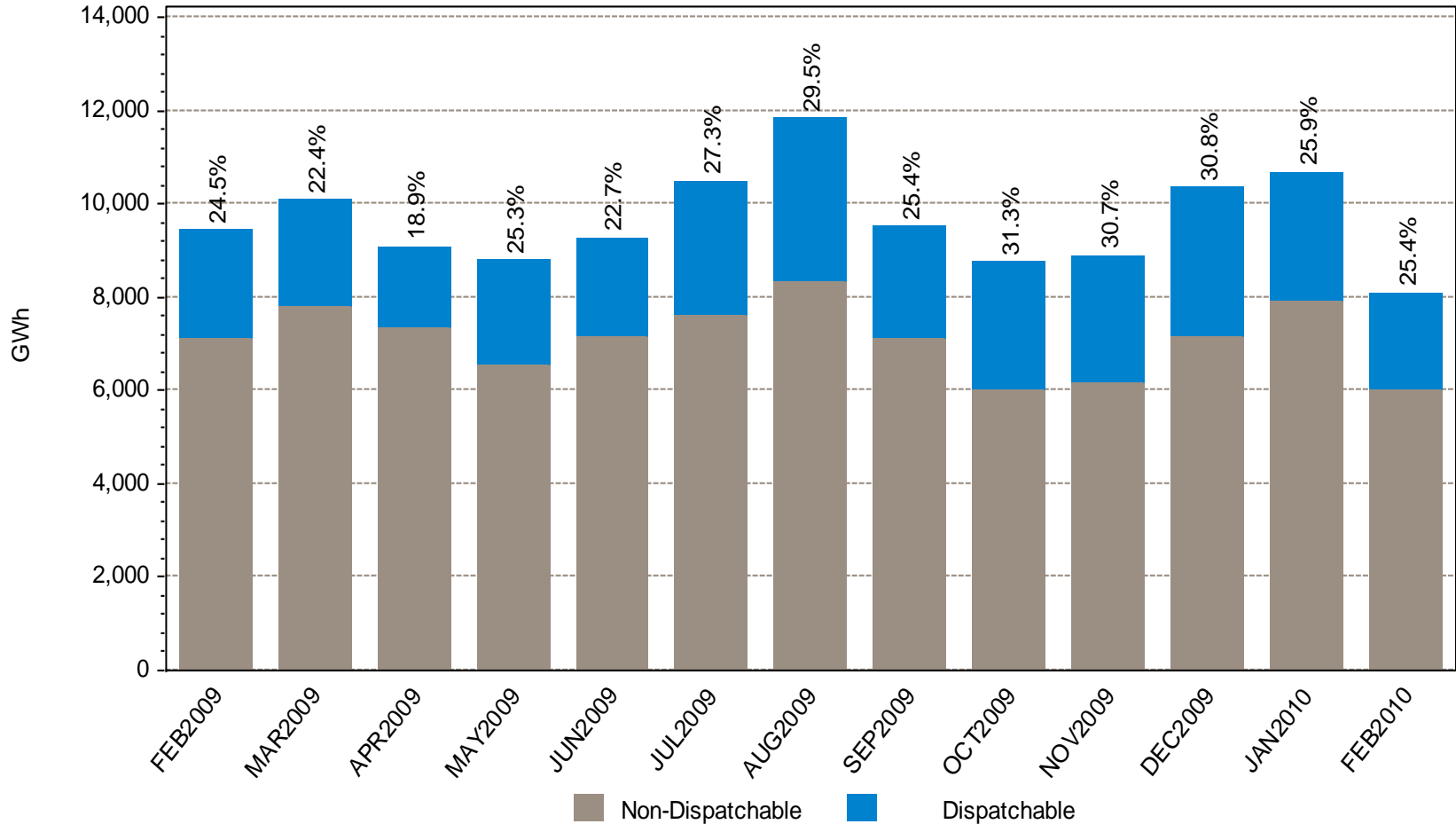
Zonal Level, Last 13 Months



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation

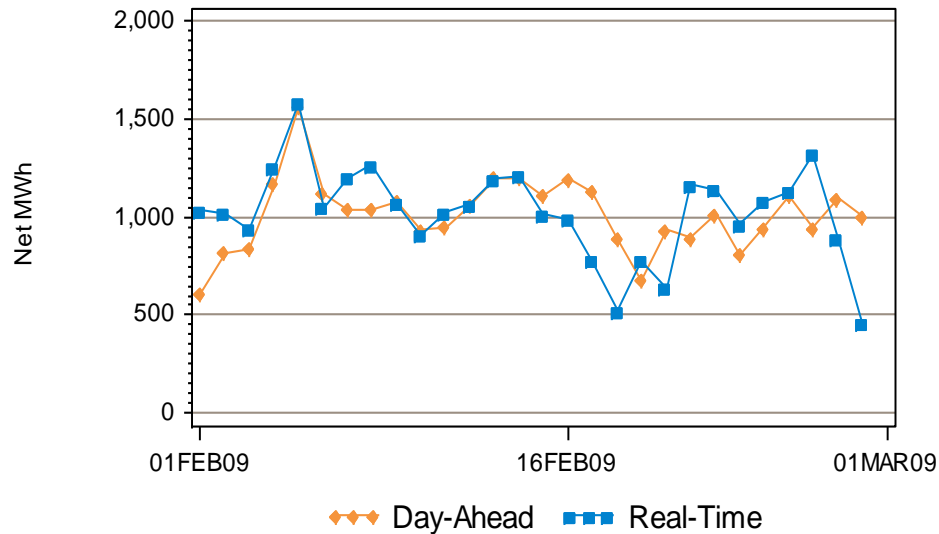
Total Monthly Energy; Dispatchable % Shown



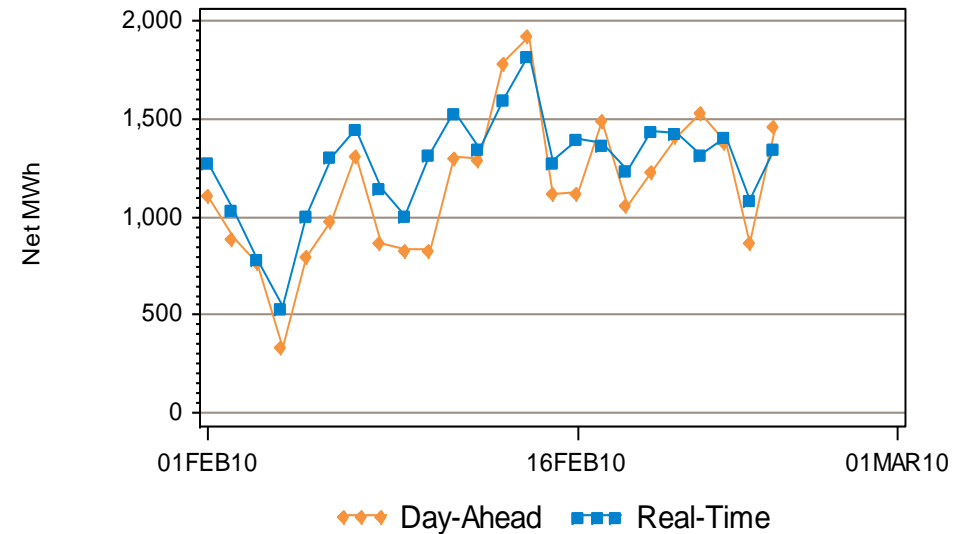
DA vs. RT Net Interchange

February 2010 vs. February 2009

Hourly Average by Day, Last Year



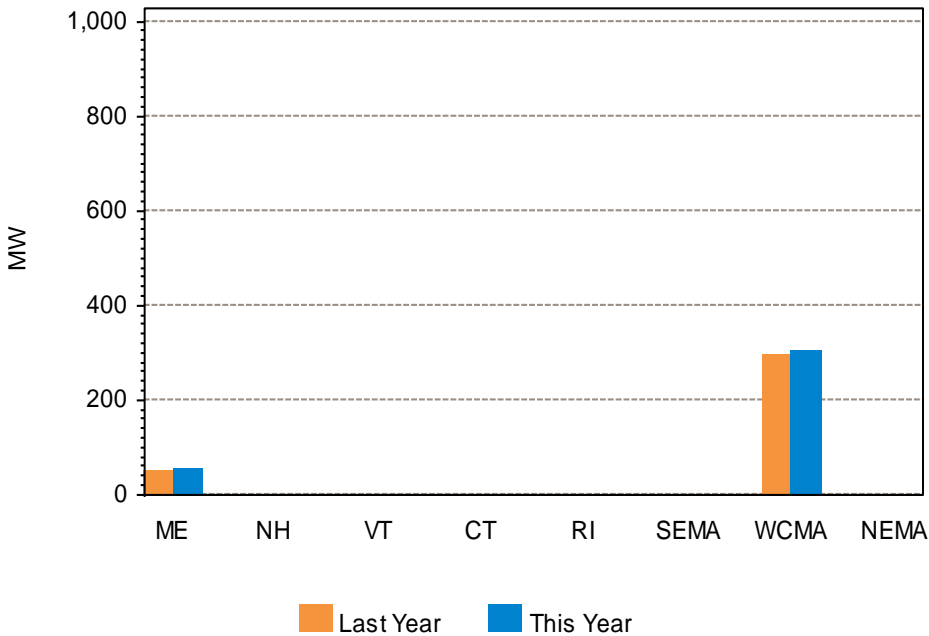
Hourly Average by Day, This Year



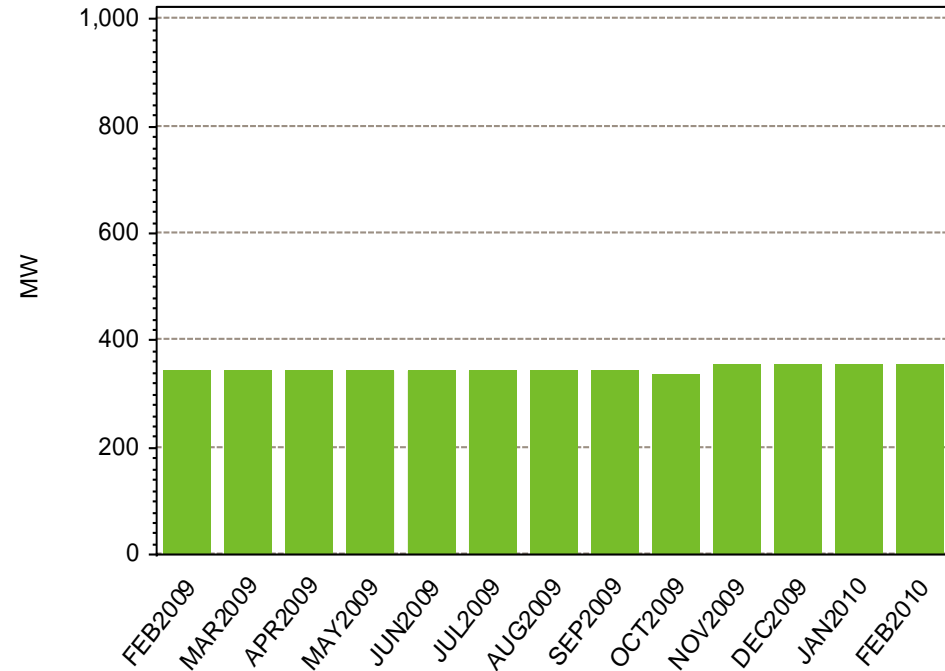
Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports

Delisted Capacity, February 2010

Delisted Capacity by Zone, This Year vs. Last Year



Total, Last 13 Months



During the Installed Capacity (ICAP) Transition Period, assets must de-list for the entire Commitment Period. The current Winter Commitment Period spans October 2009 through May 2010. The Summer Commitment Period will encompass June 2010 through September 2010.

Reliability Agreement Status Summary

Reliability Agreements

<u>Unit</u>	<u>Annual Fixed Cost⁽¹⁾</u>	<u>Summer MW*</u>	<u>\$/kw-month⁽¹⁾</u>	<u>Effective Date</u> "R" = Requested
Status: Effective with Final Federal Energy Regulatory Commission (FERC) Approval				
NRG Energy - Middletown 2-4, 10	\$49,611,273	770	\$5.37	01/01/06
NRG Energy - Montville 5, 6, 10 & 11	\$28,696,612	494	\$4.84	01/01/06
Berkshire Power	\$26,000,000	229	\$9.46	07/01/05
Con Edison - West Springfield 3	\$7,050,000	94	\$6.25	05/01/05
Pittsfield Generating - Altresco	\$13,000,000	141	\$7.68	12/01/05
Con Edison - West Springfield Gas Turbine GT-1 and GT-2	\$9,800,000	74	\$11.04	03/31/06
Public Service Enterprise Group (PSEG) - New Haven Harbor	\$37,492,000	448	\$6.97	11/18/04
PSEG - Bridgeport Harbor 2	\$14,008,000	130	\$8.98	11/18/04
NRG Energy - Norwalk Harbor 1, 2	\$32,000,000	330	\$8.08	06/19/07
Status: Terminated or Termination Pending				
NRG Energy - Devon 7 & 8 (10/1/04 & 6/7/04)	\$19,692,116	212 (retired)	\$7.74	08/01/02
Mirant Kendall Steam 1-3 & Jet 1 (5/1/07)	\$7,920,000	70	\$9.43	10/08/04
Exelon New - Boston 1 (11/16/06)	\$30,000,000	350 (deactivated)	\$7.14	01/01/02
NRG Energy - Devon 11-14 (1/1/07)	\$19,692,116	118	\$13.91	01/01/06
Boston Generating - Mystic 8 & 9 (1/1/07)	\$155,000,000	1373	\$9.41	01/01/06
PPL Corporation - Wallingford 2-5 (6/1/07)	\$22,000,000	167	\$10.98	02/01/03
Bridgeport Energy (6/1/07)	\$50,500,000	445	\$9.46	06/01/05
Dominion - Salem Harbor (last payment 7/07; obligation ended 10/08.)	\$3,375,000	741	\$0.38	07/22/05
Milford Power 1 & 2 (9/30/08)	\$72,500,000	521	\$11.60	11/03/04

⁽¹⁾Does not reflect the netting of Market Revenues, including transition payments, that are in excess of variable costs. Where FERC Settlements are pending, the settlement Annual Fixed Cost is shown.

*2009 Forecast Report of Capacity, Energy, Loads, and Transmission, or capacity at deactivation/retirement

<http://www.iso-ne.com/trans/celt/report/index.html>

Requests for Reliability Determinations

<u>Unit</u>	<u>Summer MW*</u>	<u>Zone Location</u>	<u>Date Received</u>	<u>Date of Determination</u>
Status: Needed for System Reliability				
FPL Energy Yarmouth (aka Wyman) 1 & 2	103	ME	12/11/08	06/23/09
Status: Needed for System Reliability as of date of determination - Generator did not pursue a Reliability Agreement				
Con Edison - West Springfield 10	17	WCMA	08/19/05	02/23/06
Status: Not Needed for System Reliability as of Date of Determination				
FPL Energy - Yarmouth 4	603	ME	02/11/05	05/26/05
Indeck Enfield and Jonesboro	46	ME	11/15/05	12/28/05
Ridgewood and Blackstone Tupperware	3	RI	03/02/05	05/26/05
Lowell Cogeneration	28	WCMA	10/24/05	12/28/05
Millennium Power	326	WCMA	04/08/05	06/15/05
Taunton - Cleary	26	WCMA	05/11/05	12/28/05
Con Edison - Newington	505	NH	08/19/05	12/28/05
Con Edison - Doreen	16	WCMA	08/19/05	02/23/06
Lake Road 1-3	752	RI	09/23/05	12/28/05
Granite Ridge	660	NH	11/21/05	03/31/06
Calpine - Westbrook	510	ME	10/31/05	04/26/06
Braintree - Potter 2	75	SEMA	N/A	05/25/06
Boston Generating - Fore River	682	SEMA	N/A	05/25/06
Calpine - Rumford Power	245	ME	10/31/05	12/06/06
Con Edison - Woodland Road	16	WCMA	08/19/05	02/26/07
Lowell Power (1.3.9 granted, retired 7/1/08)	N/A	WCMA	03/21/05	05/17/05
Calpine - Androscoggin (1.3.9 granted, not deactivated)	127	ME	01/27/06	04/04/06
Mirant Kendall Steam 1-3, CT	209	NEMA	03/26/07	07/12/07
Boston Generating - Mystic 7	578	NEMA	11/12/08	05/19/09

*2009 Forecast Report of Capacity, Energy, Loads, and Transmission, or capacity at deactivation/retirement

Regional System Plan (RSP)

Regional System Plan

- Planning Advisory Committee (PAC) meeting on planning process is now scheduled for March 8 to discuss
 - RSP Planning Process
 - RSP10 Scope of Work
- PAC meeting is planned for March 18 to discuss
 - Long-term Load Forecast
 - Transmission Updates
 - Fuel Diversity Discussion

Process for Submitting Economic Study Requests

- All communications to ISO should be sent to PACMatters@ISO-NE.com
- Submit requests by April 1
- To better coordinate presentations, ISO will advise all requestors of all received requests and the time allotted for each presentation by April 8
 - Presentation materials due to ISO by April 15
 - Requestor presentations to be held at the April 27 PAC meeting
 - Draft ISO Scope of Work for Economic Studies will be discussed at the May 25 PAC meeting

Interregional Planning and Coordination

- Inter-Area Planning Stakeholder Advisory Committee (IPSAC) WebEx meeting will be scheduled to discuss the Draft Northeast Coordinated System Plan 2009 Report (NCSP09) status and Next Steps
 - Stakeholders will be given three weeks to review the Draft NCSP prior to the IPSAC WebEx
- Environmental Advisory Group (EAG) teleconference scheduled for April 16

Eastern Interconnection Planning Collaborative (EIPC)

- EIPC has revised the proposal to address the issues raised at the meetings held in January with DOE and Eastern Interconnection States Planning Council (EISPC). The revised proposal was submitted to DOE on February 23
- DOE has asked that EIPC not wait and get started on the work
- EIPC has started the work to roll-up our regional plans to create a model for analysis
- Keystone has initiated the work to form the Stakeholder Steering Committee

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 3/1/10

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	3
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 3/1/10

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

Upgrade	Expected In-service	Present Stage
Expand the Carver substation	Nov-12	1
Build new 345 kV line from Carver to Sandwich	Nov-12	1
Expand Sandwich to include 345-115 kV autotransformer	Nov-12	1
Build new 115 kV line from Canal to Barnstable	Nov-12	1
Upgrade the D21 line from Bell Rock to High Hill	Nov-12	1
342/322 DCT (Separation or Exclusion)	Nov-12	1

- A lower SEMA long-term study was initiated in 4Q 2007 with an estimated completion date of 1Q 2009. Final long-term report posted on 1/20/09
- Two study updates presented to PAC during 2008
- Proposed long-term upgrades presented at 1/21/09 PAC meeting
- Received RC recommendation for I.3.9 approval on 10/20/09
- ISO I.3.9 approval on 11/5/09
- Siting effort to commence in 2010

Maine Power Reliability Program (MPRP)

Status as of 3/1/10

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

Vermont Southern Loop Project

Status as of 3/1/10

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	Jun-11*	3
Vernon 345/115 kV substation	Jun-11*	3
Newfane 345/115 kV substation	Jun-11*	3
Loop new 345 kV line into Newfane	Jun-11*	3
Coolidge 345 kV substation expansion	Jun-11*	3

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

* The Southern Loop Project is significantly ahead of schedule and some portions may be placed in service in 2010

New England East-West Solutions (NEEWS)

Status as of 3/1/10

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
- Need for IRP and CCRP under study

Transmission Siting Update

- New England East-West Solutions
 - ISO involvement in RI siting for RIRP complete
 - Siting application filed with MA and CT for Springfield portion in October 2008
 - Springfield – CT
 - ISO provided 9 hours of oral testimony on 10/27/09 and 10/28/09
 - No further ISO involvement anticipated
 - CT Siting Council approved entire project except for the Manchester – Meekville Junction double-circuit separation portion (known as MMP)
 - Springfield – MA
 - ISO provided three days of oral testimony the last week of January
 - No further ISO involvement anticipated

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
 - Siting proceedings currently in progress
 - Hearings have been completed, but the possibility of future technical conferences and settlement discussions still exists
 - ISO continues to respond to data requests

Operable Capacity Analysis

Winter/Spring 2010 Operable Capacity Analysis (MW)

	May-10* 50/50 Forecast (Reference Load)	May-10* 90/10 Forecast (Extreme Load)
Installed Resources (Based on the February Seasonal Claimed Capability (SCC) Report)	33,562	SAME
Net ICAP Purchases	58	SAME
New Generation	200	SAME
Net Resources***	33,820	SAME
Assumed Outages**	9,892	SAME
Generation at Risk Due to Gas Supply	0	SAME
Peak Load Exposure (adjusted for Other Demand Resources)	20,681	22,154 (+1473)
Reserve Requirement	1800	SAME
Operable Capacity Required	22,481	23,954 (+1473)
Operable Capacity Margin***	1450	-30 (-1480)

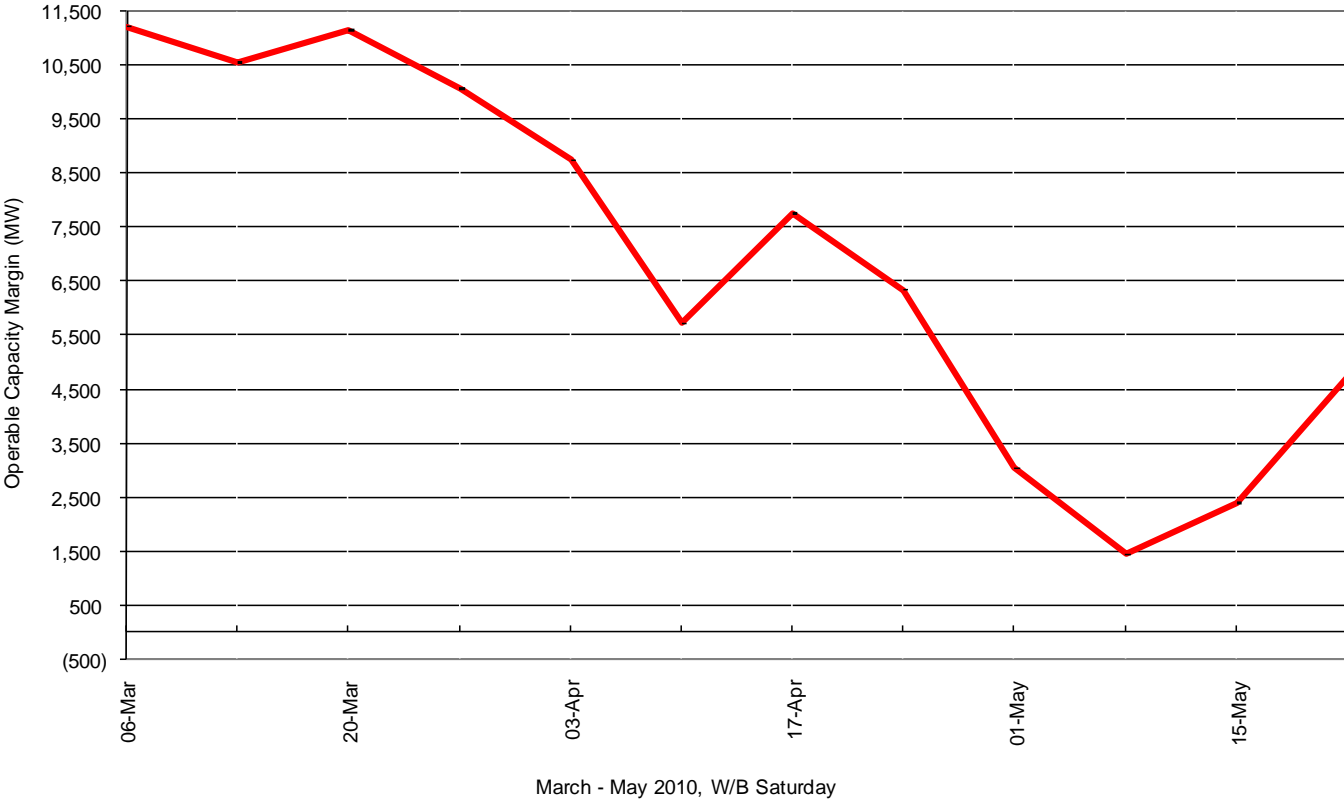
•Based on week with lowest Operable Capacity Margin, week beginning May 8th. Mystic 8 & 9 limited to 1,200 MW. Does not include Settlement Only Resources (approx. 250 MW) and Demand Response Resources (2,291 MW).

** Assumed Outages include 3,400 MW of Unplanned Outages, and 6,492 MW of Planned Outages

*** Rounded to the nearest ten

Winter/Spring 2010 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)

New England Operable Capacity Margins
WITH KNOWN EXTERNAL TRANSACTIONS - 50/50 FORECAST



Winter/Spring 2010 Operable Capacity Analysis (MW) 90/10 Forecast (Extreme)

New England Operable Capacity Margins
WITH KNOWN EXTERNAL TRANSACTIONS - 90/10 FORECAST



Possible Relief Under OP4 (before 6/1/10)

OP 4 Action Number	Action Description	Amount Assumed Obtainable Under OP 4 (MW)
3	Interrupt 2-hour and Profile DR Resources*	253
6	Reduce 30-minute Operating Reserves	600
9	Interrupt 30-minute DR Resources*	824
11	Schedule Emergency Energy Transactions	1,000
12	Interrupt Additional DR Resources*	1,143
	Voltage Reduction requiring > 10 minutes	82
13	Voltage Reduction requiring < 10 minutes	366
15	Radio and TV Appeal	200
Total		4,468

- Total Demand Response MW, including voluntary price response = 2,291 MW (voluntary price response = 71 MW)
- Demand Response based on data as of 1/29/2010
- OP-4 Actions based on a 28,048 MW system load

Summer 2010 Operable Capacity Analysis (MW)

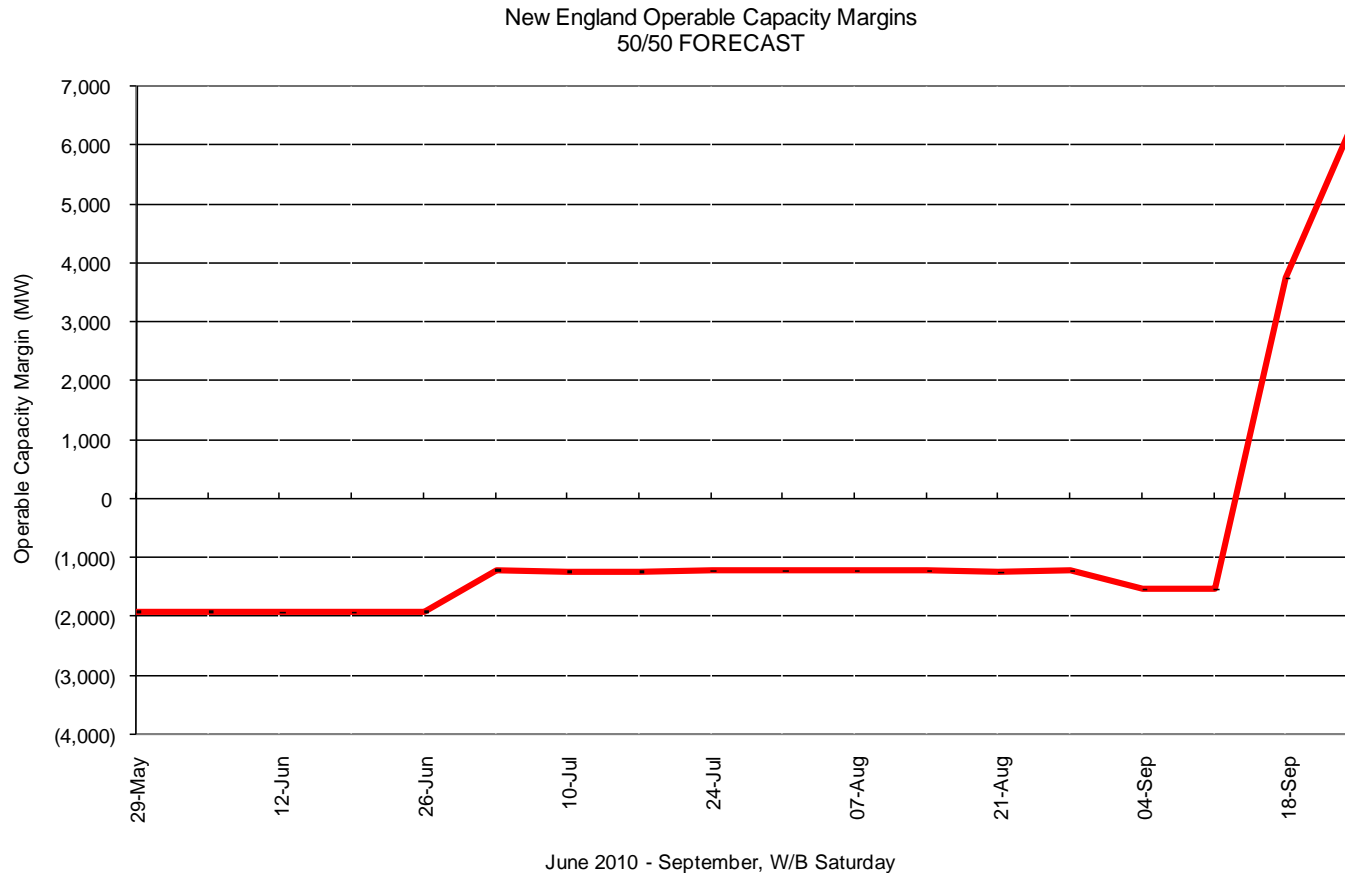
	June-10* 50/50 Forecast (Reference Load)	June-10* 90/10 Forecast (Extreme Load)
Available Capacity (based on resource Capacity Supply Obligation, CSO minus Planned Outages)	29,856	SAME
External Node Available capacity	373	SAME
Non Commercial Supply	0	SAME
Net Capacity	30,229	SAME
Allowance for Unplanned Outages	2,800	SAME
Generation at Risk Due to Gas Supply	0	SAME
Peak Load Exposure (adjusted for Other Demand Resources)	27,560	29,510 (+1950)
Reserve Requirement	1,800	SAME
Operable Capacity Required	29,360	31,310 (+1950)
Operable Capacity Margin***	(1,930)	(3,880) (-1950)

•Based on week with lowest Operable Capacity Margin, weeks beginning June 12th and June 19th. Mystic 8 & 9 limited to 1,200 MW. Does not include Settlement Only Resources and Demand Response Resources.

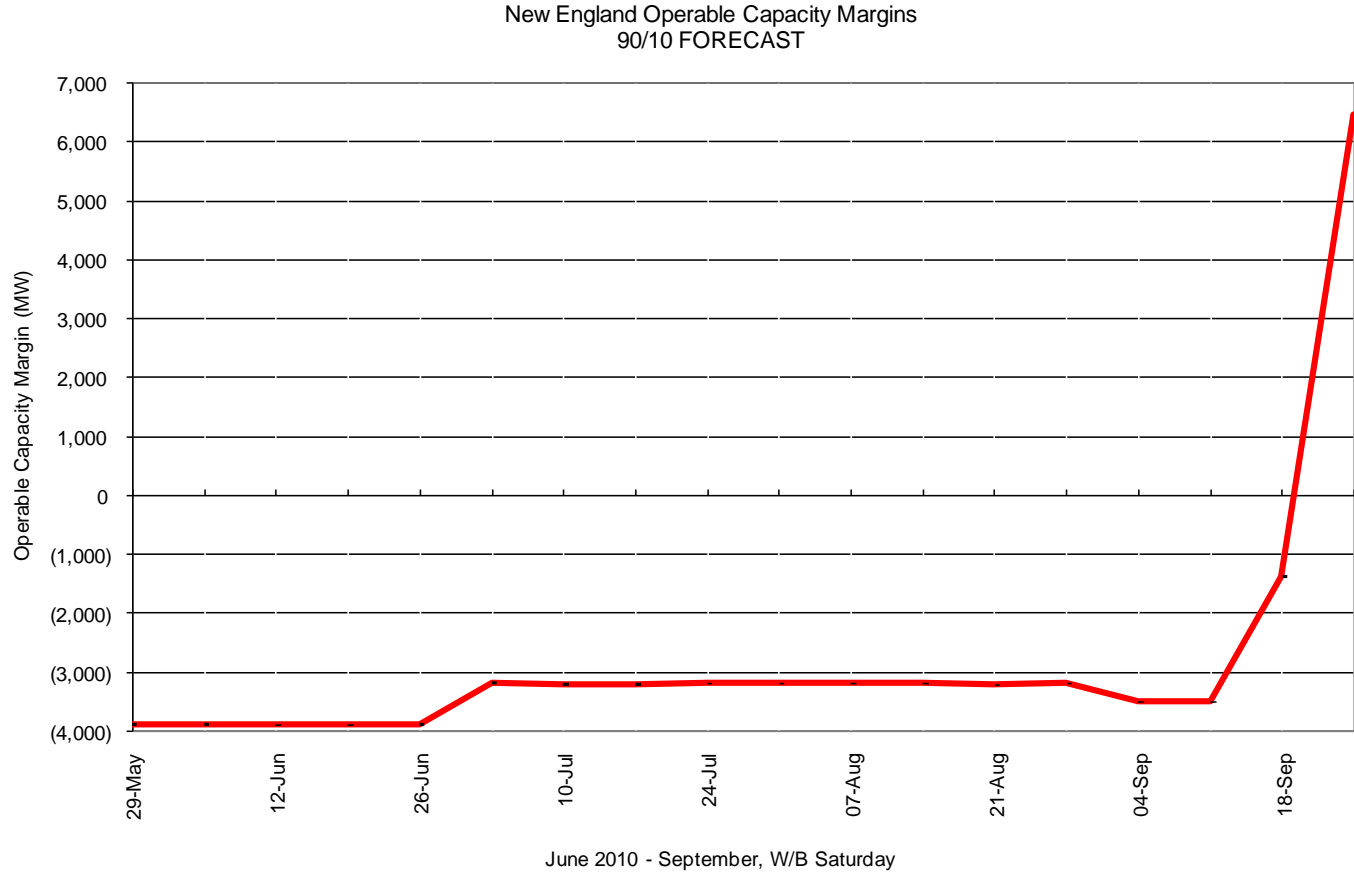
** Assumed Outages include 2,800 MW of Unplanned Outages, and 0 MW of Planned Outages

*** Rounded to the nearest ten

Summer 2010 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)



Summer 2010 Operable Capacity Analysis (MW) 90/10 Forecast (Extreme)



Appendix

Winter/Spring 2010 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

March 1 , 2010 - WITH KNOWN EXTERNAL CONTRACTS - 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.

Week Beginning, Saturday															
Year	Month	Day	Installed Seasonal Claimed Capability (SCC) [Note 1] <i>(MW)</i>	Net Interchange (NYPP, NB, HQ, Highgate) [Note 2] <i>(MW)</i>	New Generation [Note 3] <i>(MW)</i>	De-listed ICAP resources [Note 4] <i>(MW)</i>	Net Capacity [Note 5] <i>(MW)</i>	Peak Load Exposure [Note 6] <i>(MW)</i>	Operating Reserve Requirement [Note 7] <i>(MW)</i>	(Planned Outages) Total Known Maintenance [Note 8] <i>(MW)</i>	Allowance for Unplanned Outages [Note 8] <i>(MW)</i>	Generation at Risk Due to Gas Supply [Note 9] <i>(MW)</i>	Total Capacity <i>(MW)</i>	Operable Capacity Margin (+/-) <i>(MW)</i>	Extent of OP 4 Actions That May be Necessary (OP 4 Actions up to and including) [Note 10]
	March	6	33,544	1,789	200	290	35,529	19,424.00	1,800	884	2,200	0	32,445	11,220	
		13	33,544	1,789	200	290	35,529	19,230.00	1,800	1,748	2,200	0	31,581	10,550	
		20	33,544	1,789	200	290	35,529	18,867.00	1,800	1,515	2,200	0	31,814	11,150	
		27	33,555	1,789	200	290	35,539	18,306.00	1,800	3,167	2,200	0	30,172	10,070	
	April	3	33,555	58	200	290	33,808	17,804.00	1,800	3,258	2,200	0	28,350	8,750	
		10	33,555	58	200	290	33,808	17,554.00	1,800	6,020	2,700	0	25,088	5,730	
		17	33,555	58	200	290	33,808	17,048.00	1,800	4,505	2,700	0	26,603	7,760	
2010		24	33,555	58	200	290	33,808	16,785.00	1,800	6,179	2,700	0	24,929	6,340	
	May	1	33,562	58	200	290	33,818	16,748.00	1,800	8,816	3,400	0	21,602	3,050	
		8	33,562	58	200	290	33,818	20,681.00	1,800	6,492	3,400	0	23,926	1,450	
		15	33,562	58	200	290	33,818	21,669.00	1,800	4,545	3,400	0	25,873	2,400	
		22	33,562	58	200	290	33,818	22,587.00	1,800	1,298	3,400	0	29,120	4,730	

Notes: Please note that the information contained within the Capacity Analysis is a deterministic projection of system conditions which could materialize during any given week of the year

1. Installed Capability per the February 1, 2010 SCC report, Energy Management System units, with an adjustment for capability increases and decreases expected during the analysis period (SCC = Seasonal Claimed Capability). The Operable Capacity does not reflect possible transmission constraints within the ISO New England system.
2. Net Interchange is based on known capacity-backed (ICAP) contracts. This column combines monthly data, as it becomes available, with preliminary contract totals recorded in the 2009 Capacity, Energy, Loads, and Transmission - CELT Report.
3. New Generation information includes a) generation recently commercial but not yet reflected in the ISO New England SCC Report totals used in the Installed Capability Column, and b) future generation as assumed by ISO-NE System Planning Department. This value is rounded to the nearest hundred.
4. Delisted capacity is only known for the current month. Projections are based on known delisted capacity sales.
5. Net Capacity = (SCC) + (Interchange) + (New Generation) - (Delisted ICAP Sold) In this equation, values for SCC, Interchange and De-listed ICAP sold are rounded to the nearest ten (SCC = Seasonal Claimed Capability).
6. Peak Load Exposure per data included in the 2009 CELT Report with an adjustment for Other Demand Resources.
7. Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency.
8. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance.
9. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions.
10. Relief from certain OP 4 Actions varies depending on system conditions.

Winter/Spring 2010 Operable Capacity Analysis (MW) 90/10 Forecast (Extreme)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

March 1 , 2010 - WITH KNOWN EXTERNAL CONTRACTS - 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.

Week Beginning, Saturday			Installed Seasonal Claimed Capability (SCC) [Note 1]	Net Interchange (NYPP, NB, HQ, Highgate) [Note 2]	New Generation [Note 3]	De-listed ICAP resources [Note 4]	Net Capacity [Note 5]	Peak Load Exposure [Note 6]	Operating Reserve Requirement [Note 7]	(Planned Outages) Total Known Maintenance [Note 8]	Allowance for Unplanned Outages [Note 8]	Generation at Risk Due to Gas Supply [Note 9]	Total Capacity [Note 10]	Operable Capacity Margin (+/-)	Extent of OP 4 Actions That May be Necessary (OP 4 Actions up to and including) [Note 10]
Year	Month	Day	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	
	March	6	33,544	1,789	200	290	35,529	20,103	1,800	884	2,200	0	32,445	10,540	
		13	33,544	1,789	200	290	35,529	19,902	1,800	1,748	2,200	0	31,581	9,880	
		20	33,544	1,789	200	290	35,529	19,527	1,800	1,515	2,200	0	31,814	10,490	
2010	April	27	33,555	1,789	200	290	35,539	18,946	1,800	3,167	2,200	0	30,172	9,430	
		3	33,555	58	200	290	33,808	18,428	1,800	3,258	2,200	0	28,350	8,120	
		10	33,555	58	200	290	33,808	18,170	1,800	6,020	2,700	0	25,088	5,120	
2010	May	17	33,555	58	200	290	33,808	17,647	1,800	4,505	2,700	0	26,603	7,160	
		24	33,555	58	200	290	33,808	17,375	1,800	6,179	2,700	0	24,929	5,750	
		1	33,562	58	200	290	33,818	17,336	1,800	8,816	3,400	0	21,602	2,470	
	May	8	33,562	58	200	290	33,818	22,154	1,800	6,492	3,400	0	23,926	(30)	Action 2
		15	33,562	58	200	290	33,818	23,211	1,800	4,545	3,400	0	25,873	860	
		22	33,562	58	200	290	33,818	24,193	1,800	1,298	3,400	0	29,120	3,130	

- Notes: Please note that the information contained within the Capacity Analysis is a deterministic projection of system conditions which could materialize during any given week of the year
1. Installed Capability per the February 1, 2010 SCC report. Energy Management System units, with an adjustment for capability increases and decreases expected during the analysis period (SCC = Seasonal Claimed Capability). The Operable Capacity does not reflect possible transmission constraints within the ISO New England system.
 2. Net Interchange is based on known capacity-backed (ICAP) contracts. This column combines monthly data, as it becomes available, with preliminary contract totals recorded in the 2009 Capacity, Energy, Loads, and Transmission - CELT Report.
 3. New Generation information includes a) generation recently commercial but not yet reflected in the ISO New England SCC Report totals used in the Installed Capability Column, and b) future generation as assumed by ISO-NE System Planning Department. This value is rounded to the nearest hundred.
 4. Delisted capacity is only known for the current month. Projections are based on known delisted capacity sales.
 5. Net Capacity = (SCC) + (Interchange) + (New Generation) - (Delisted ICAP Sold) In this equation, values for SCC, Interchange and De-listed ICAP sold are rounded to the nearest ten (SCC = Seasonal Claimed Capability).
 6. Peak Load Exposure per data included in the 2009 CELT Report with an adjustment for Other Demand Resources.
 7. Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency.
 8. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance.
 9. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions.
 10. Relief from certain OP 4 Actions varies depending on system conditions.

Summer 2010 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

March 1, 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.

Week Beginning, Saturday

STUDY WEEK	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL OPCAP MW	NET OPCAP SUPPLY MW	NON COMMERCIAL CAPACITY MW	LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	GEN RISK DUE TO GAS SUP MW	UNPLANNED OUTAGES MW	OPCAP MARGIN MW	OPCAP FROM OP4 MW	OPCAP MARGIN OP4 MW
05/29/2010	29,867	373	30,241	0	27,560	1,800	0	2,800	(1,919)	488	(1,432)
06/05/2010	29,866	373	30,239	0	27,560	1,800	0	2,800	(1,921)	488	(1,433)
06/12/2010	29,856	373	30,229	0	27,560	1,800	0	2,800	(1,931)	488	(1,443)
06/19/2010	29,856	373	30,229	0	27,560	1,800	0	2,800	(1,931)	488	(1,443)
06/26/2010	29,867	373	30,240	0	27,560	1,800	0	2,800	(1,920)	488	(1,432)
07/03/2010	29,867	373	30,240	0	27,560	1,800	0	2,100	(1,220)	488	(732)
07/10/2010	29,845	373	30,218	0	27,560	1,800	0	2,100	(1,242)	488	(754)
07/17/2010	29,844	373	30,218	0	27,560	1,800	0	2,100	(1,242)	488	(755)
07/24/2010	29,863	373	30,236	0	27,560	1,800	0	2,100	(1,224)	488	(736)
07/31/2010	29,858	373	30,231	0	27,560	1,800	0	2,100	(1,229)	488	(741)
08/07/2010	29,860	373	30,233	0	27,560	1,800	0	2,100	(1,227)	488	(739)
08/14/2010	29,855	373	30,228	0	27,560	1,800	0	2,100	(1,232)	488	(744)
08/21/2010	29,837	373	30,211	0	27,560	1,800	0	2,100	(1,249)	488	(762)
08/28/2010	29,860	373	30,233	0	27,560	1,800	0	2,100	(1,227)	488	(739)
09/04/2010	29,539	373	29,913	0	27,560	1,800	0	2,100	(1,547)	488	(1,060)
09/11/2010	29,540	373	29,914	0	27,560	1,800	0	2,100	(1,546)	488	(1,059)
09/18/2010	27,261	373	27,634	0	19,995	1,800	0	2,100	3,739	488	4,227
09/25/2010	27,365	373	27,738	0	17,260	1,800	0	2,100	6,578	488	7,066

1. Available OPCAP MW based on reouse Capacity Supply Obligations, CSO, during the Forward Capacity Market procurement period from June 2010 through May 2011 taking into account Planned Outage reductions.
2. External Node Available OPCAP MW based on external Capacity Supply Obligations, CSO, during the Forward Capacity Market procurement period from June 2010 through May 2011.
3. NET OPCAP SUPPLY = AVAIL OPCAP + EXTERNAL NODE AVAIL OPCAP. AVAIL OPCAP takes into account known Planned Outages.
4. Peak Load Exposure per data included in the 2009 CELT Report with an adjustment for Other Demand Resources.
5. Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency.
6. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance.
7. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions.

Summer 2010 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

March 1, 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.

Week Beginning, Saturday												
STUDY WEEK	LZ EXPORT LTD AVAIL OPCAP MW	EXTERNAL NODE AVAIL OPCAP MW	OPCAP SUPPLY MW	NON COMMERCIAL CAPACITY MW	LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	GEN RISK DUE TO GAS SUP MW	UNPLANNED OUTAGES MW	OPCAP MARGIN MW	OPCAP FROM OP4 MW	OPCAP MARGIN OP4 MW	
05/29/2010	29,867	373	30,241	0	29,510	1,800	0	2,800	(3,869)	488	(3,382)	
06/05/2010	29,866	373	30,239	0	29,510	1,800	0	2,800	(3,871)	488	(3,383)	
06/12/2010	29,856	373	30,229	0	29,510	1,800	0	2,800	(3,881)	488	(3,393)	
06/19/2010	29,856	373	30,229	0	29,510	1,800	0	2,800	(3,881)	488	(3,393)	
06/26/2010	29,867	373	30,240	0	29,510	1,800	0	2,800	(3,870)	488	(3,382)	
07/03/2010	29,867	373	30,240	0	29,510	1,800	0	2,100	(3,170)	488	(2,682)	
07/10/2010	29,845	373	30,218	0	29,510	1,800	0	2,100	(3,192)	488	(2,704)	
07/17/2010	29,844	373	30,218	0	29,510	1,800	0	2,100	(3,192)	488	(2,705)	
07/24/2010	29,863	373	30,236	0	29,510	1,800	0	2,100	(3,174)	488	(2,686)	
07/31/2010	29,858	373	30,231	0	29,510	1,800	0	2,100	(3,179)	488	(2,691)	
08/07/2010	29,860	373	30,233	0	29,510	1,800	0	2,100	(3,177)	488	(2,689)	
08/14/2010	29,855	373	30,228	0	29,510	1,800	0	2,100	(3,182)	488	(2,694)	
08/21/2010	29,837	373	30,211	0	29,510	1,800	0	2,100	(3,199)	488	(2,712)	
08/28/2010	29,860	373	30,233	0	29,510	1,800	0	2,100	(3,177)	488	(2,689)	
09/04/2010	29,539	373	29,913	0	29,510	1,800	0	2,100	(3,497)	488	(3,010)	
09/11/2010	29,540	373	29,914	0	29,510	1,800	0	2,100	(3,496)	488	(3,009)	
09/18/2010	27,261	373	27,634	0	25,096	1,800	0	2,100	(1,362)	488	(874)	
09/25/2010	27,365	373	27,738	0	17,371	1,800	0	2,100	6,467	488	6,955	

1. Available OPCAP MW based on reouse Capacity Supply Obligations, CSO, during the Forward Capacity Market procurement period from June 2010 through May 2011 taking into account Planned Outage reductions.
2. External Node Available OPCAP MW based on external Capacity Supply Obligations, CSO, during the Forward Capacity Market procurement period from June 2010 through May 2011.
3. NET OPCAP SUPPLY = AVAIL OPCAP + EXTERNAL NODE AVAIL OPCAP. AVAIL OPCAP takes into account known Planned Outages.
4. Peak Load Exposure per data included in the 2009 CELT Report with an adjustment for Other Demand Resources.
5. Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency.
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