

# NEPOOL Participants Committee Report

## April 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**
  - March natural gas prices over the period were 27% lower while oil prices were 4.1% higher than February 2010 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were down 26.6% from February 2010 averages

Underlying natural gas data furnished by:



# Highlights (cont'd.)

- **Daily Net Commitment Period Compensation (NCPC)\***
  - March payments total \$1.3M over the period, up \$97K from February
  - First Contingency payments total \$1.1M, up \$8K from February
    - \$823K paid to internal resources, down \$141K from February
      - \$51K charged to DALO, \$772K to RT Deviations
    - \$240K paid to resources at external locations, up \$149K from February
      - \$62K charged to DALO at external locations, \$178K to RT Deviation
  - Second Contingency payments total \$21K, down \$135K from the February total of \$156K
  - Voltage payments total \$256K, up \$256K from February
  - Distribution payments total \$4K, down \$32K from February
  - NCPC payments as percent of Energy Market value were 0.3%

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

# Highlights (cont'd.)

- Planning Advisory Committee (PAC) meeting is planned for April 27 to discuss several topics including Stakeholder Requests for 2010 Economic Studies
- Eastern Interconnection Planning Collaborative (EIPC) work is underway. Key stakeholder meeting is scheduled for April 22-23

# Highlights (cont'd.)

- The lowest Spring Operable Capacity Margin is being calculated for the week beginning May 8<sup>th</sup>.
- The lowest Summer Operable Capacity Margin is being calculated for the week beginning June 5<sup>th</sup>.

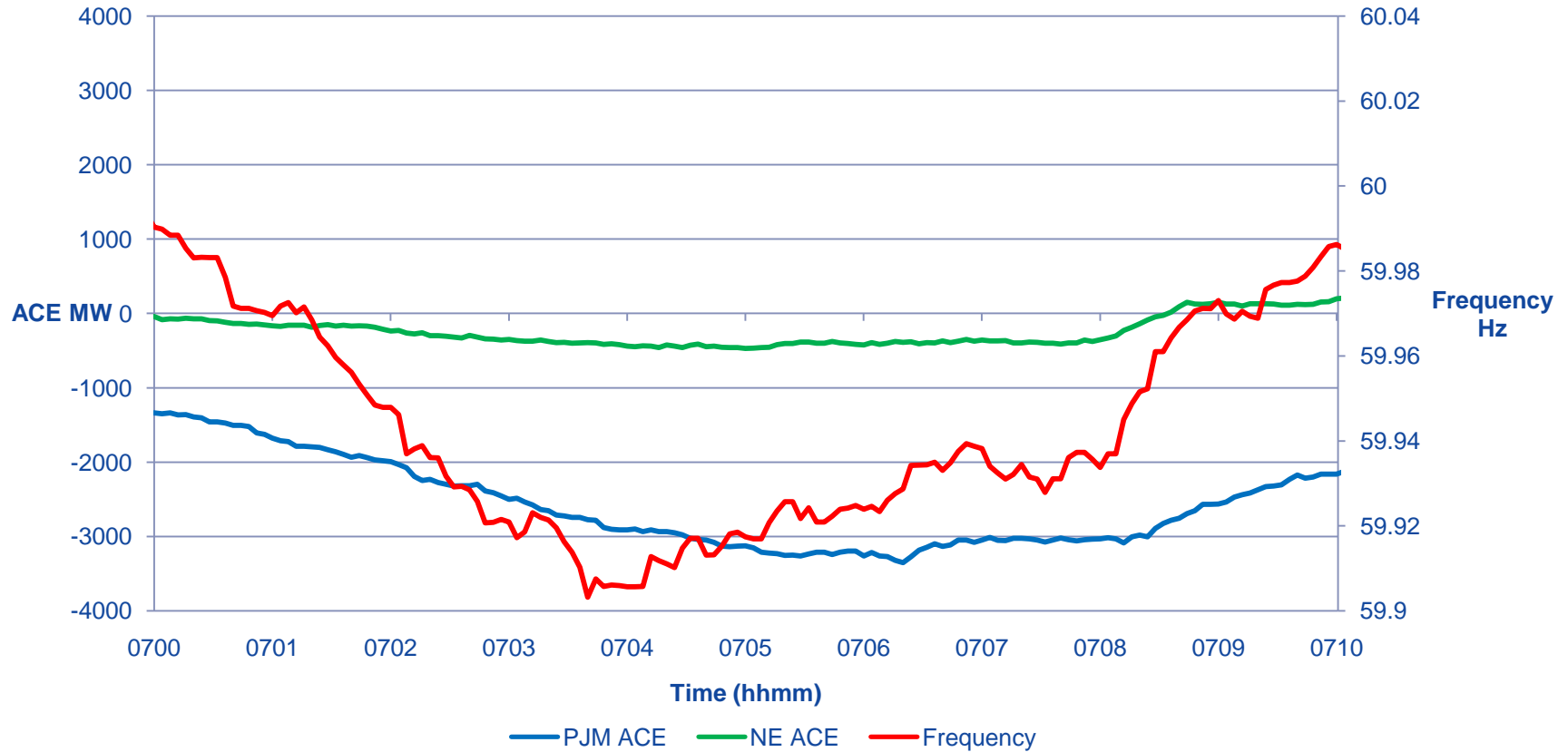
# Eastern Interconnection Frequency Excursions During March

# Noticeable Frequency Excursions

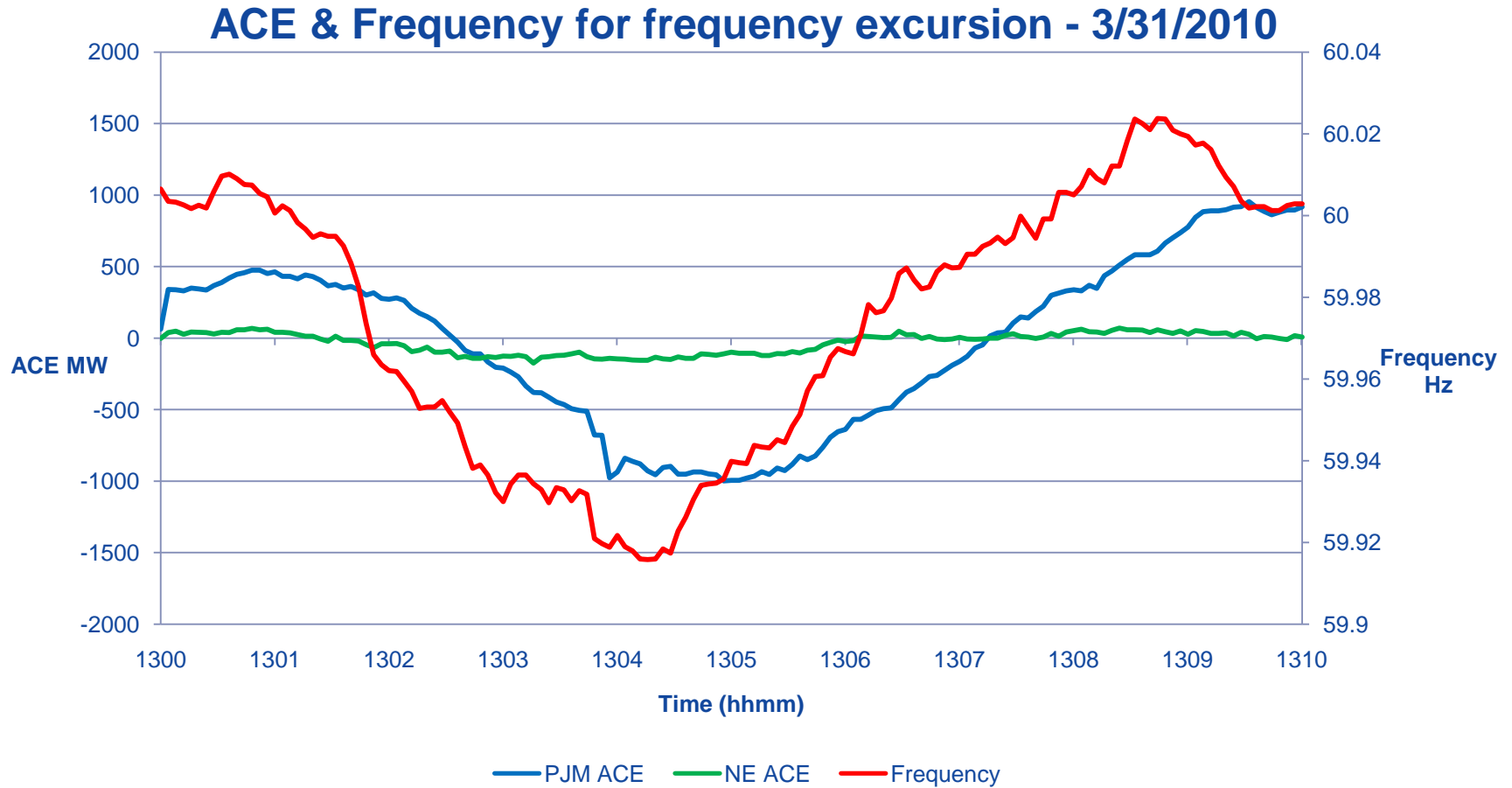
- Two noticeable frequency excursions experienced during March
  - 3/18/10 @ 07:03 Hrs frequency dropped to 59.903 Hz
  - 3/31/10 @ 13:04 Hrs frequency dropped to 59.915 Hz
- 3/18/10 event - PJM was off schedule (area control error ACE -3,000 MW) and requested NPCC shared activation of reserve to assist in recovering their ACE
- 3/31/10 event - cause unknown, although PJM off schedule by -1,500 MW.

# March 18, 2010 - Frequency Excursion

## ACE & Frequency for frequency excursion - 3/18/2010



# March 31, 2010 - Frequency Excursion



Note: time error correction (59.98Hz) started at 13:00

# Frequency Excursions Subject to Industry Review

- Normal process is for the industry to review frequency excursions
- NPCC and NERC working groups will review these frequency excursion events
- These events will also be used to collect data on the overall frequency response of the Eastern Interconnection





# Capital Projects Update

# Introduction

- The ISO's 2010 project portfolio has a higher risk profile in comparison to previous years
- The first half of 2010 will mark the completion of the following projects
  - Upgrade of the Oracle database
  - Installation of a state-of-the-art Communications Infrastructure to communicate with and dispatch assets
  - SMD Software Upgrade Phase II
  - Forward Capacity Market (FCM) Phase III
  - Demand Resource Integration (DRI)

# Consolidated Project Dashboard

- Based on the current status, the following table is a consolidated dashboard of the projects listed on Slide 3

<b>Budget</b>	
<b>Schedule</b>	
<b>Scope</b>	
<b>Risks*</b>	

- \* If risks are not adequately mitigated, it may impact project scope, budget or schedule

# Project Risks

- The risk in the 2010 project portfolio is introduced by the following elements
  - High degree of interdependency across projects
  - Complexity and uniqueness of the projects being implemented
  - High degree of impact to ISO reliability and market functions
  - High degree of readiness required from market participants
  - Limited flexibility in implementation timelines

# Project Interdependencies

- The DRI and FCM projects are dependent on the upgraded Oracle database and new Communications Infrastructure
  - An upgrade of the Oracle database platform is essential to stay current with the vendor's product evolution
  - The current Demand Resource communication infrastructure is not secure and vulnerable to failure
- The ISO has been upgrading the SMD software in a phased manner to deal with technology obsolescence and to improve performance and efficiency
  - These upgrades are required for implementation of certain components of the DRI project

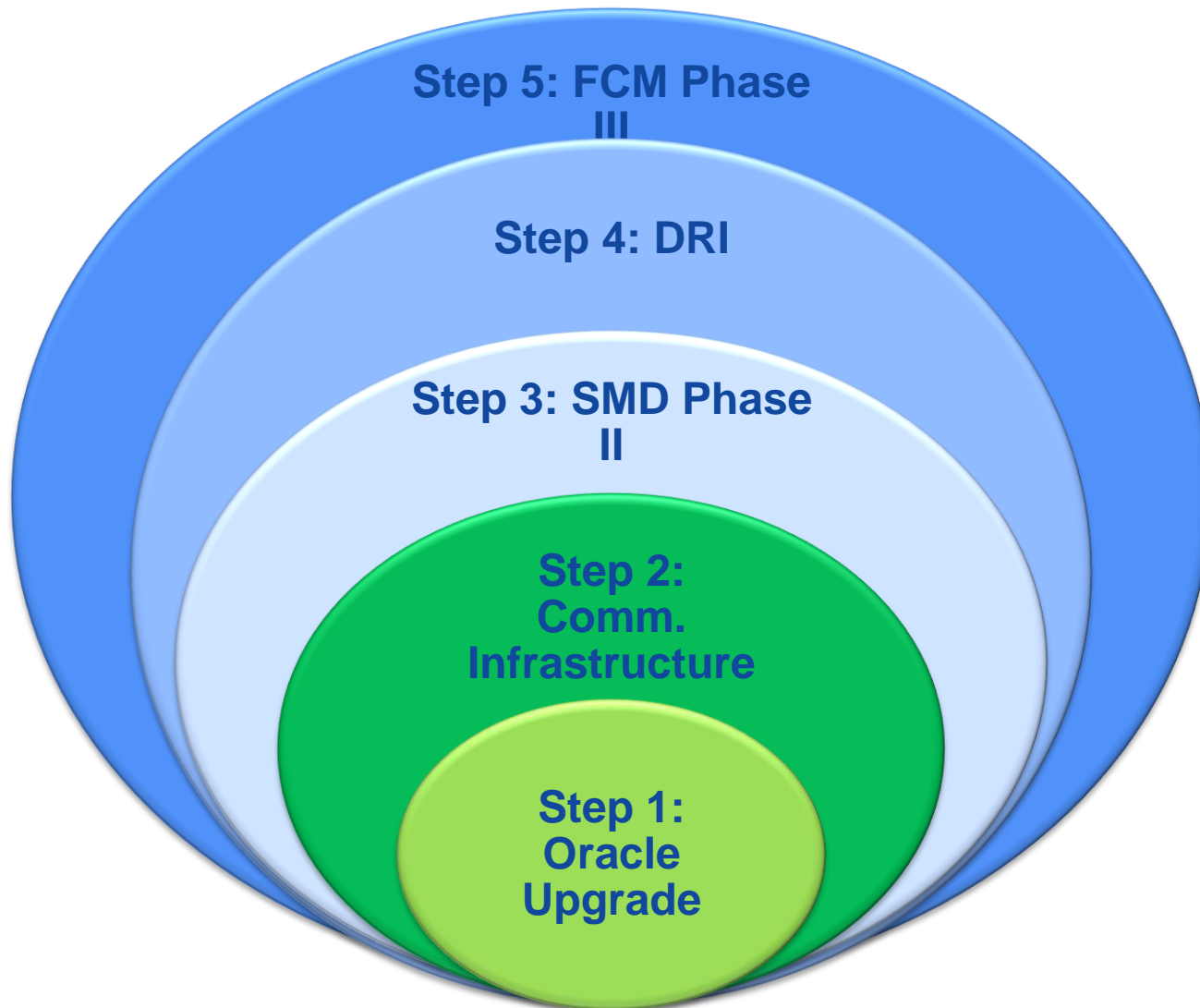
# Project Interdependencies (Continued)

- The Settling of the FCM depends on the timely implementation of the DRI project
  - Settlement of demand resources is based on complicated baseline measures and resulting performance calculations for demand resources
  - Baseline and performance calculations for demand resources require the new Communications Infrastructure
- Delays in one project impact other projects
  - Delays in the Oracle upgrade would affect the SMD Phase II project, which would affect the DRI project, which would affect the FCM Phase III project
  - Similarly, delays in the readiness of the Communications Infrastructure would affect the DRI project, which would affect the FCM Phase III project

# Project Sequencing

- The ISO project sequence calls for the following steps
  - Step 1: Complete implementation of Oracle Upgrade of Markets Database in March (Completed)
  - Step 2: Complete implementation of Communications Infrastructure by May 24
  - Step 3: Complete implementation of SMD Phase II by May 28
  - Step 4: Complete implementation of DRI by May 31
  - Step 5: Complete implementation of FCM Phase III by May 31
  - **Step 6: Projects completed and in-service on June 1**

# Project Sequencing (Continued)



# Risk Mitigation

- The ISO has taken the following steps to mitigate the implementation risks
  - Ensure that these projects continue to be fully resourced
    - Resource needs are continually monitored
    - Any resource gaps are proactively identified and resourced via consultants
  - Weekly project meetings and quick issue escalation
  - Build an extended testing period into the project schedule
  - Test projects in an integrated, rather than sequential, manner
  - Use ‘live’ data and execute end-to-end tests

# Risk Mitigation (Continued)

- The ISO has taken the following steps to mitigate the implementation risks
  - Stress-testing of the systems
  - Sandbox testing with participants to ensure their readiness
  - Simulator-based training for control room operators
  - Regular training sessions for employees and participants
  - Active change management to minimize scope increase
  - Pre-implementation audits by Internal Audit and KPMG to ensure readiness of controls

# System Operations

# System Operations

<b><u>Weather Patterns:</u></b>	Boston	Temperature – Above Average Precipitation – Much Above Average	Hartford	Temperature – Above Average Precipitation – Much Above Average
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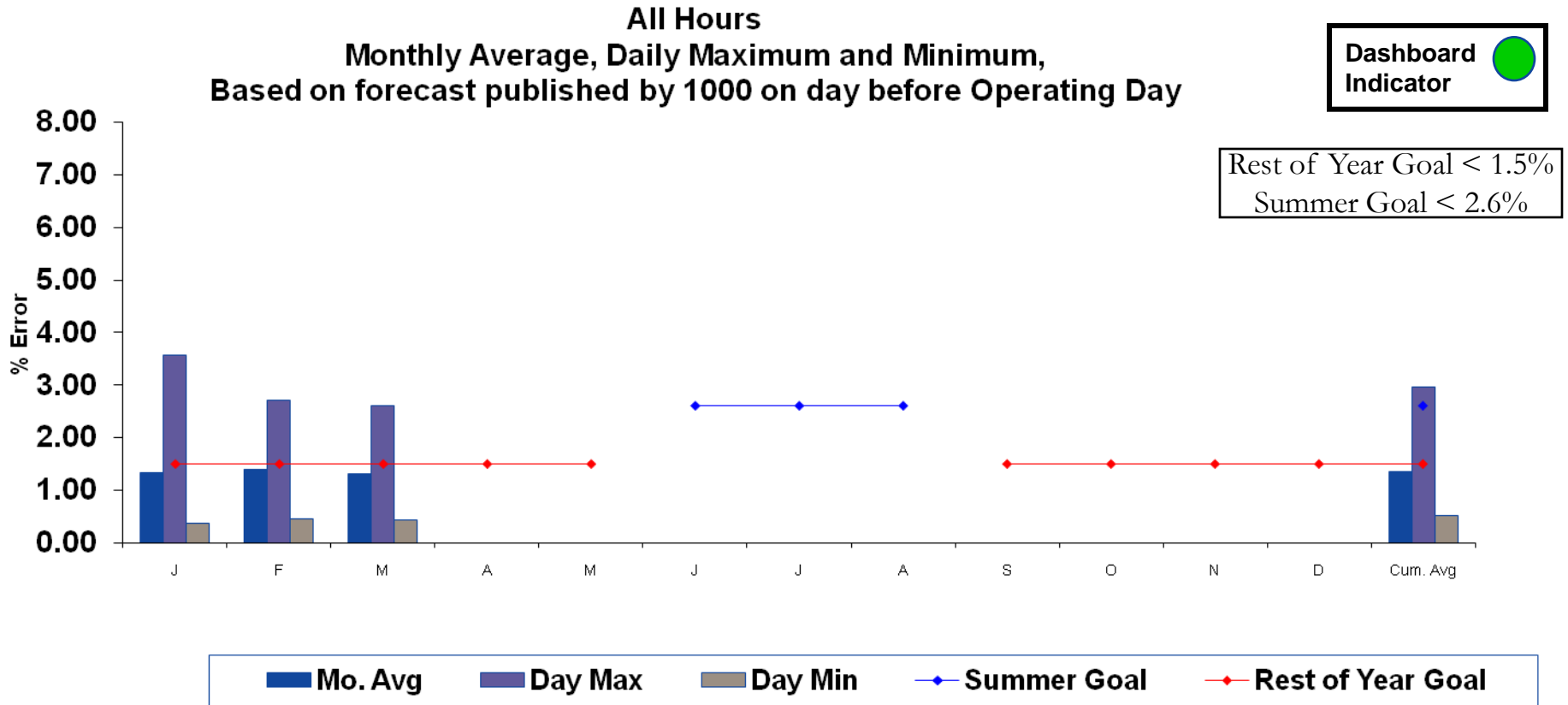
<b><u>Peak Load:</u></b>	18153 MW	<b>March 3, 2010</b>	19:00
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<b><u>Minimum Generation Emergencies :</u></b> 3/21, 3/25
<b><u>MLCC2:</u></b> 3/14 - Real time contract curtailment due to low reserves.

<b><u>OP-4 :</u></b> 3/14 - Initial reserve issues followed by MK2 trip, PAWP trip, BSW2 OOS due to lack of water, NFD3 OOS due to lack of water, plus numerous fast start units OOS due to failure to start.
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<b><u>NPCC Shared Activation of Reserve Events:</u></b>			
Mar 15	Loss of Canal 2	ISO-NE	570 MW
Mar 18	Low ACE (No generation loss identified- frequency 59.91 hz.)	PJM	
Mar 23	Loss of Rockport 2	PJM	1300 Mw

# 2010 System Operations - Load Forecast Accuracy



	J	F	M	A	M	J	J	A	S	O	N	D	Avg	
<b>Mo Avg</b>	1.33	1.39	1.31										1.34	Mo Avg
<b>Day Max</b>	3.57	2.72	2.62										2.97	Day Max
<b>Day Min</b>	0.37	0.45	0.43										0.40	Day Min
<b>Summer Goal</b>						2.60	2.60	2.60						
<b>Rest of Year Goal</b>	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50		
Current YTD ROY Avg.													1.43	

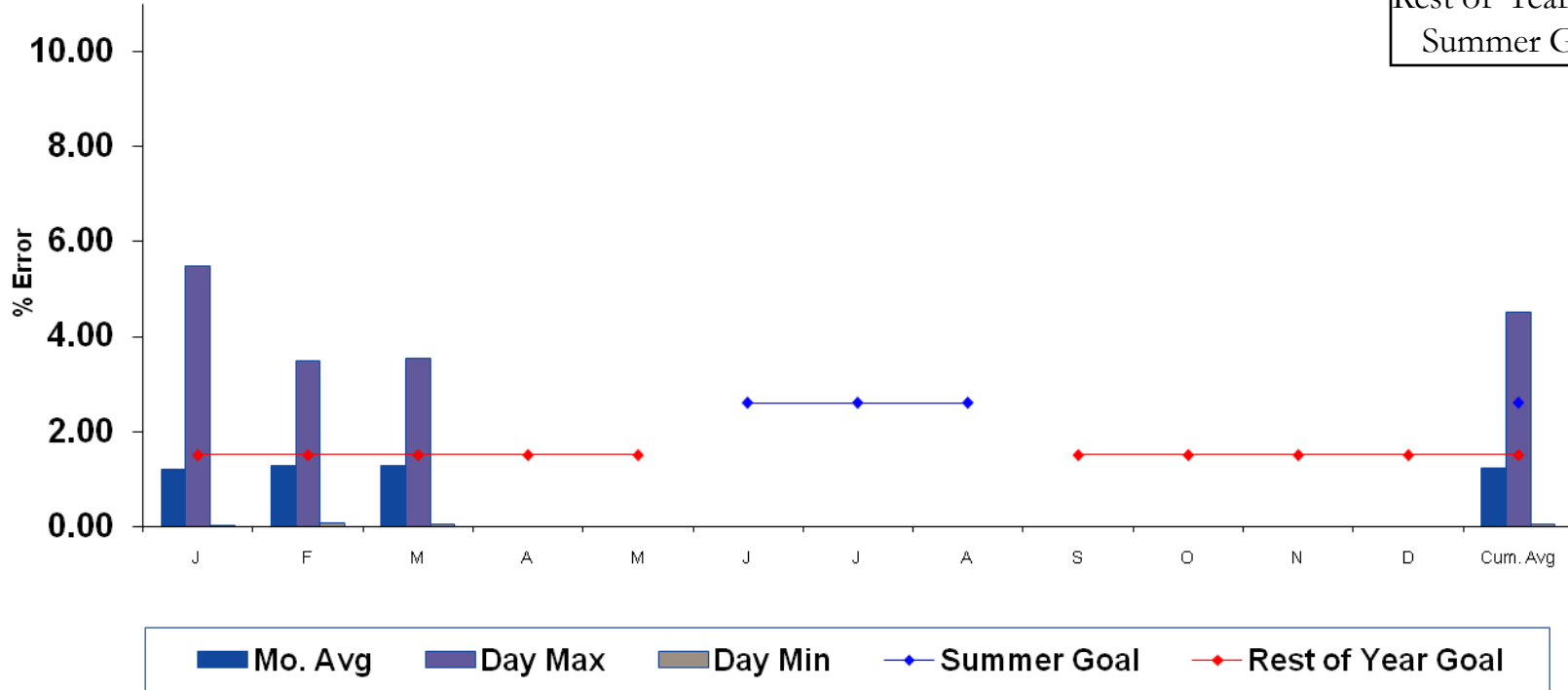
<b>Contact: Steve Weaver</b>												
Summer Goal = 2.6% Rest of Year Goal = 1.5%												
Summer consists of June, July and August-												

# 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%



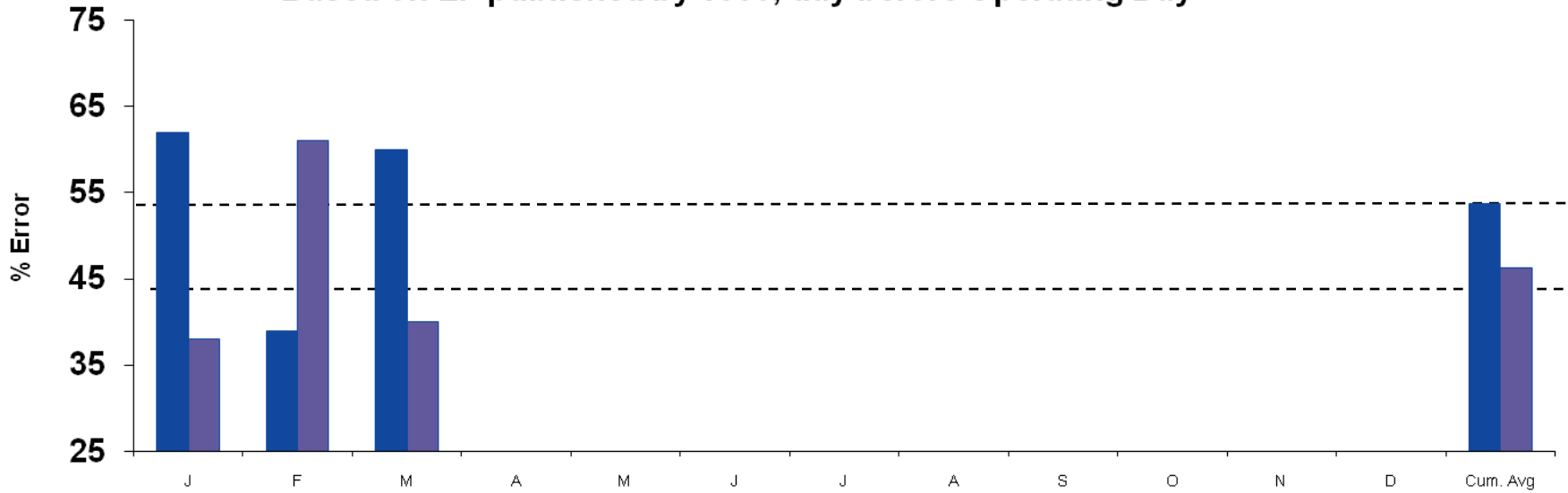
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.20	1.28	1.28										1.24
Day Max	5.49	3.49	3.55										4.50
Day Min	0.03	0.07	0.05										0.05
Summer Goal						2.6	2.6	2.6					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Current YTD ROY													

<b>Contact:</b> 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%

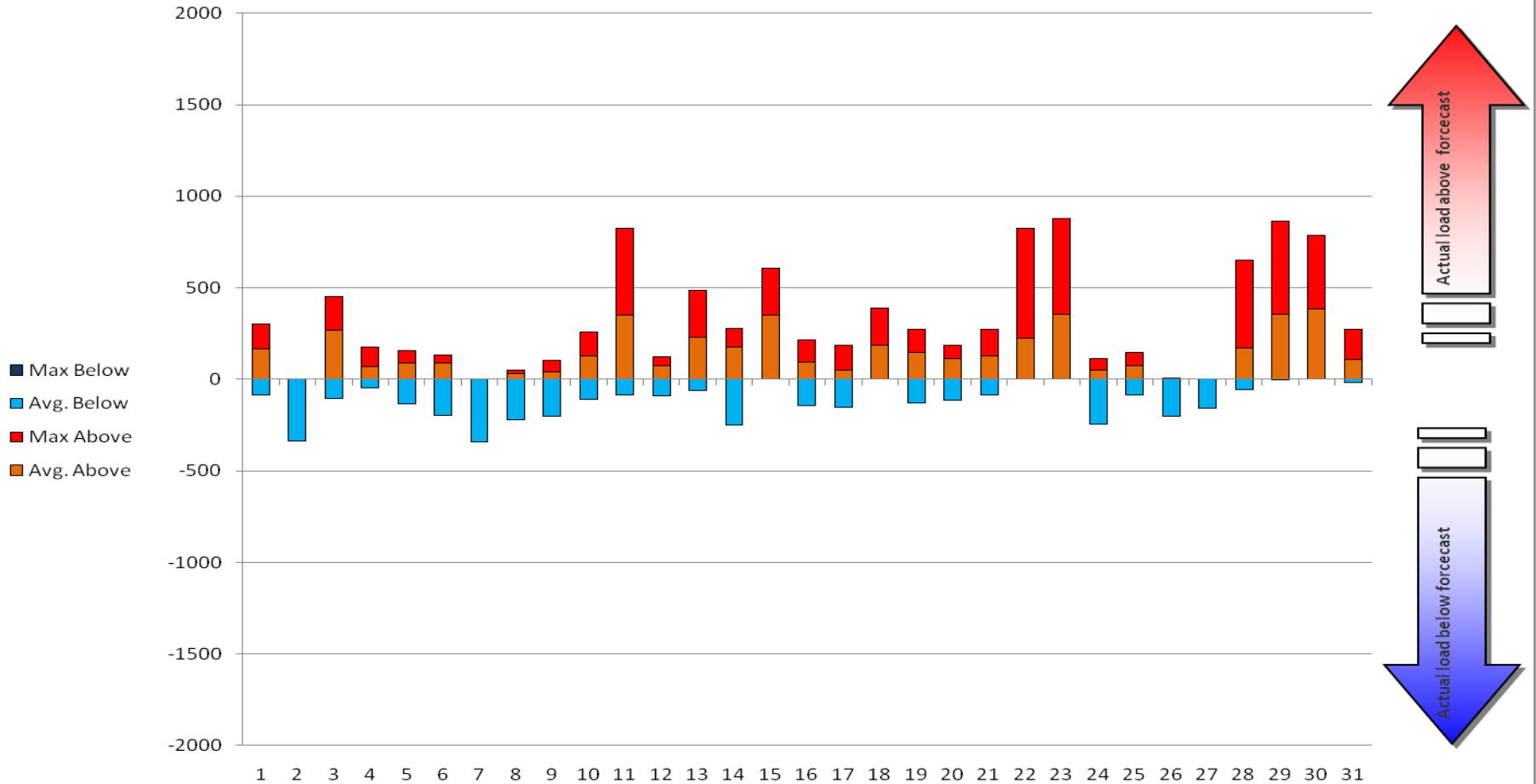


■ Above ■ Below

	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												

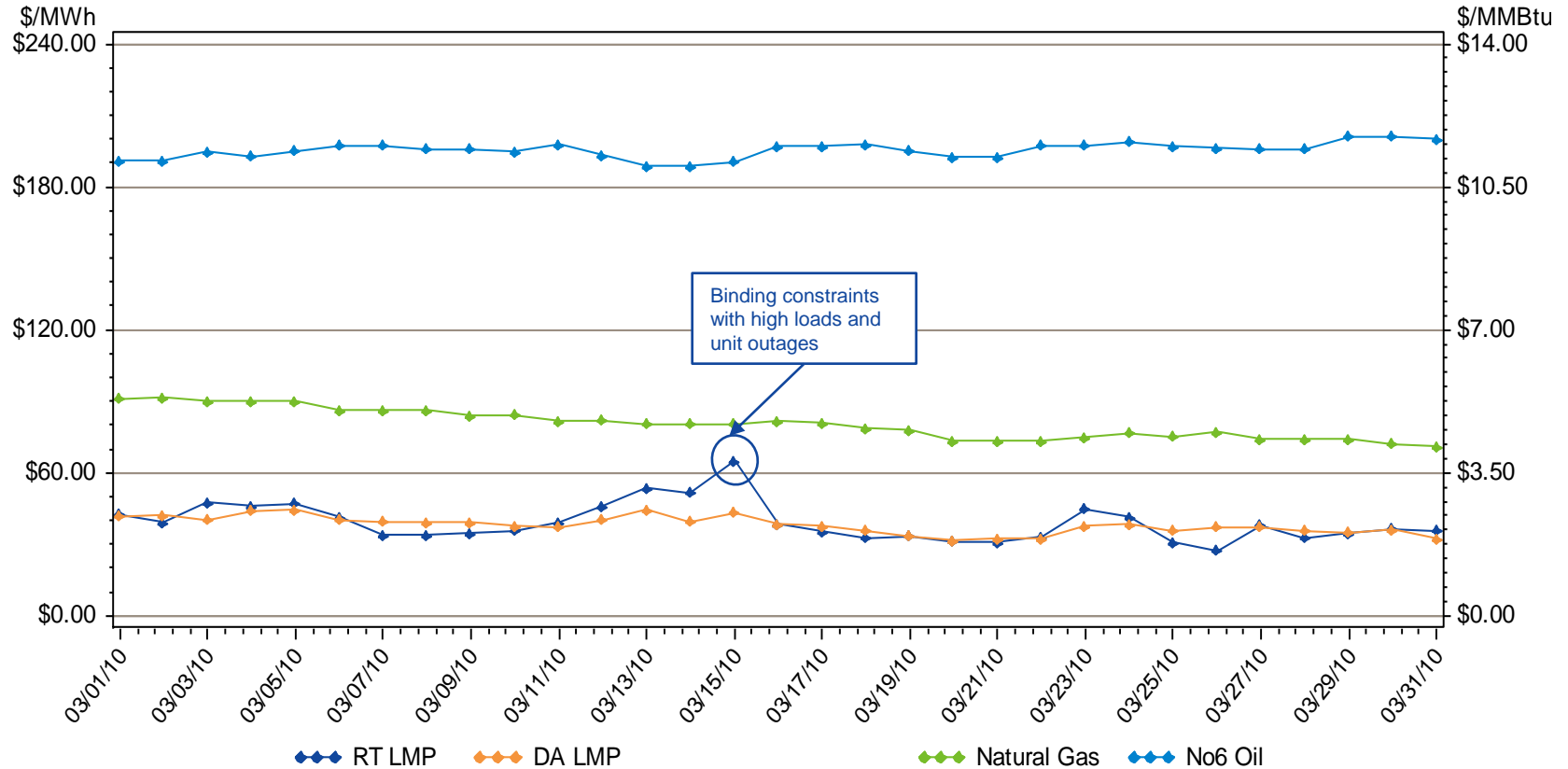
### Deviation of Actual Load from Forecasted Load March 2010



Sponsor	Mike Taniwha
Contact	Steve Weaver

# Market Operations

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



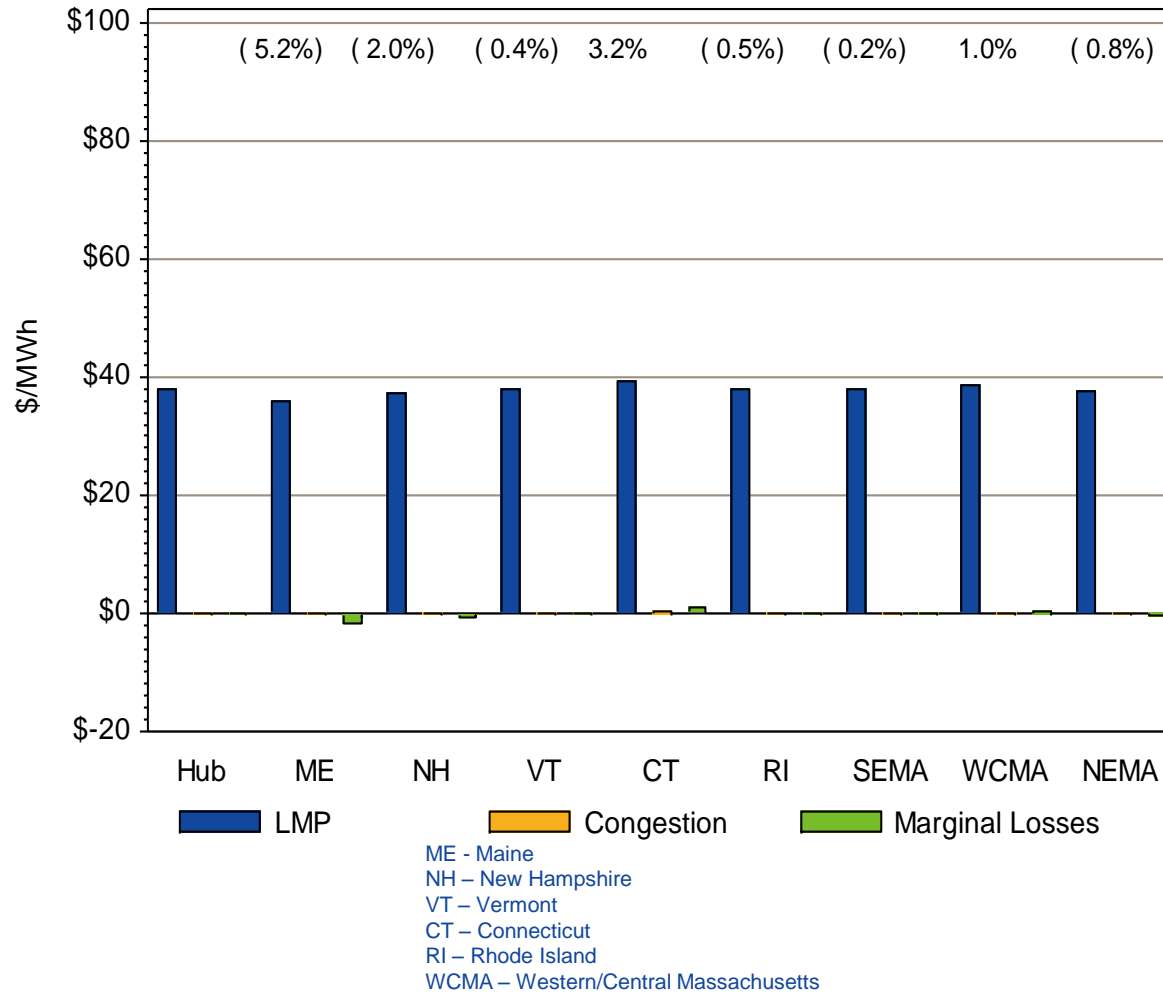
Underlying natural gas data furnished by:



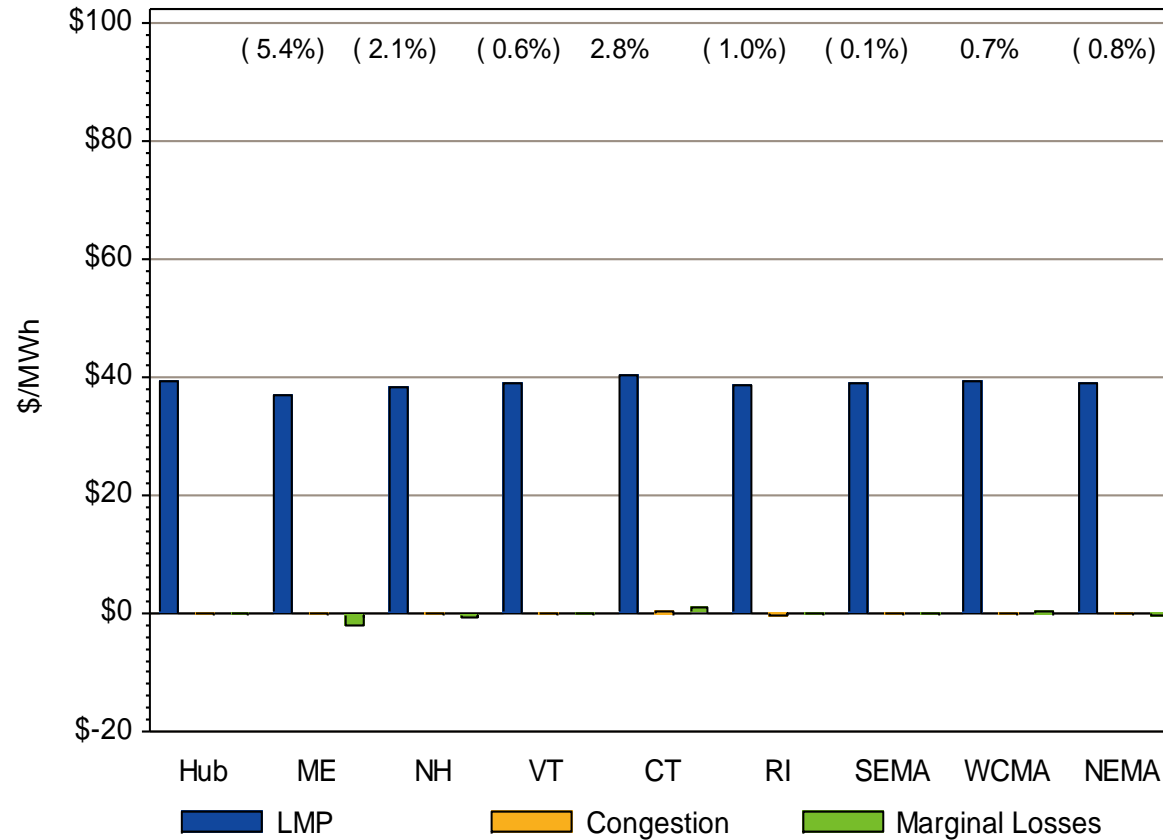
Average price difference over this period (DA-RT): \$-1.11  
 Average price difference over this period ABS(DA-RT): \$4.07  
 Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 10%

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 – March 2010

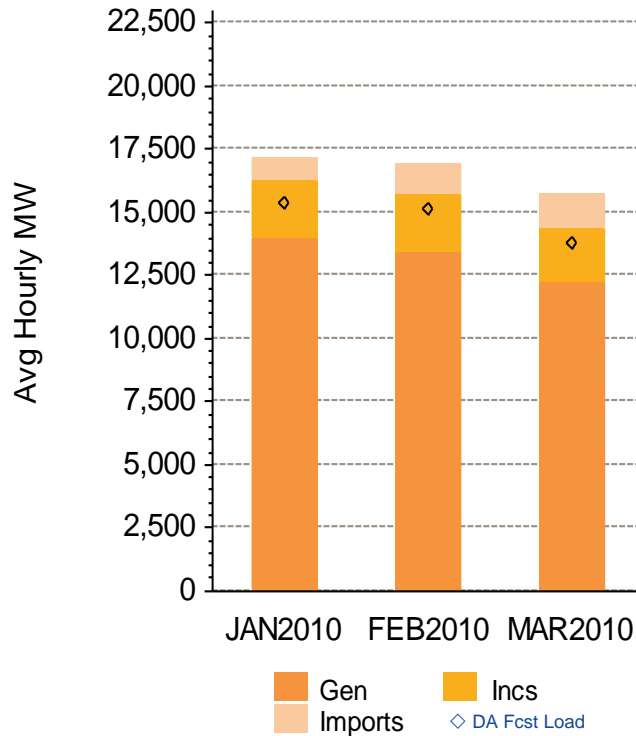


# RT LMPs Average by Zone & Hub – March 2010



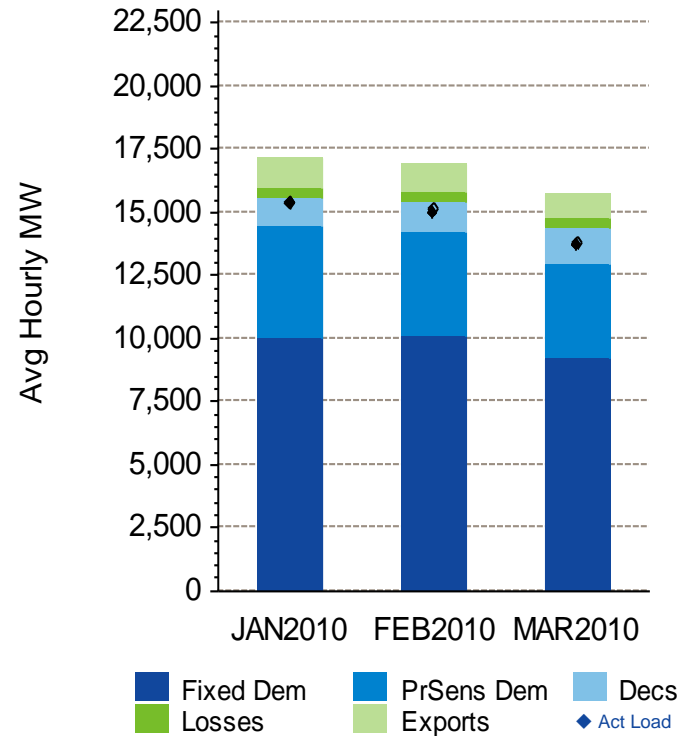
# Components of Cleared DA Supply and Demand – Last Three Months

Supply



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

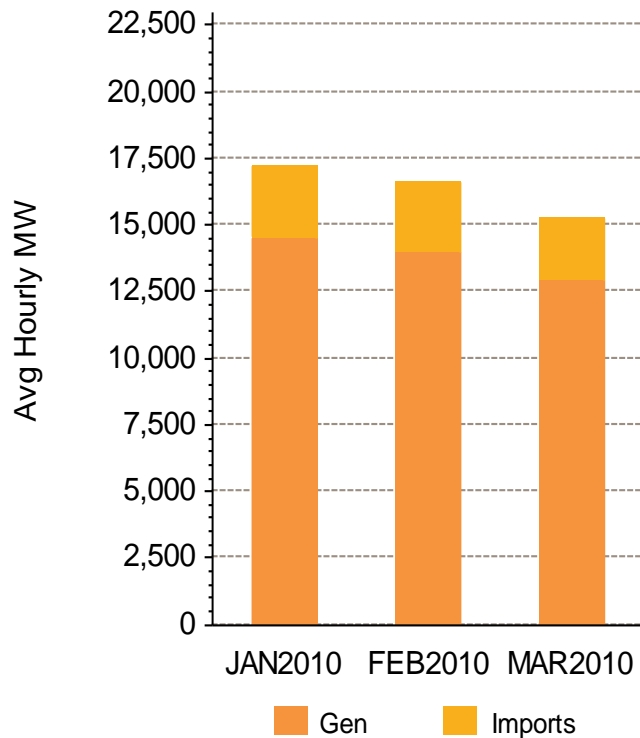
Demand



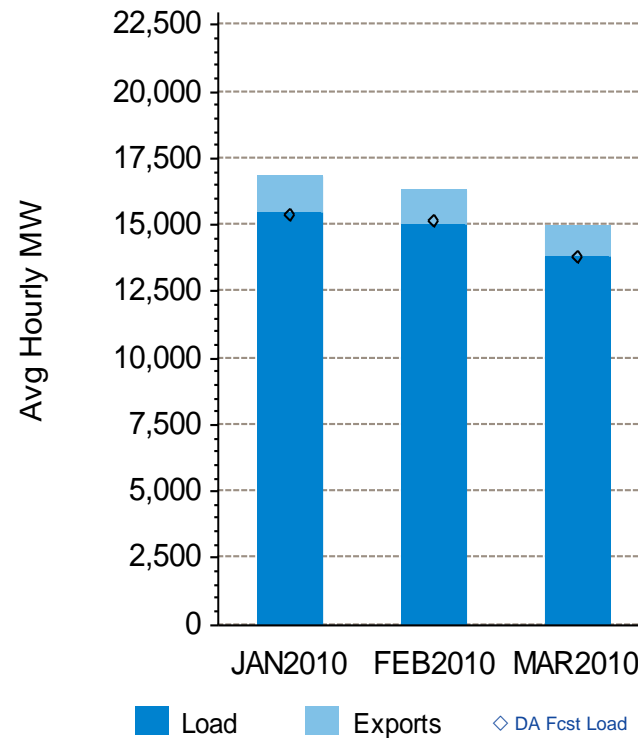
Fixed Dem – Fixed Demand  
 PrSens Dem – Price Sensitive Demand  
 Decs – Decrement Bids  
 Act Load – Actual Load

# Components of RT Supply and Demand – Last Three Months

Supply

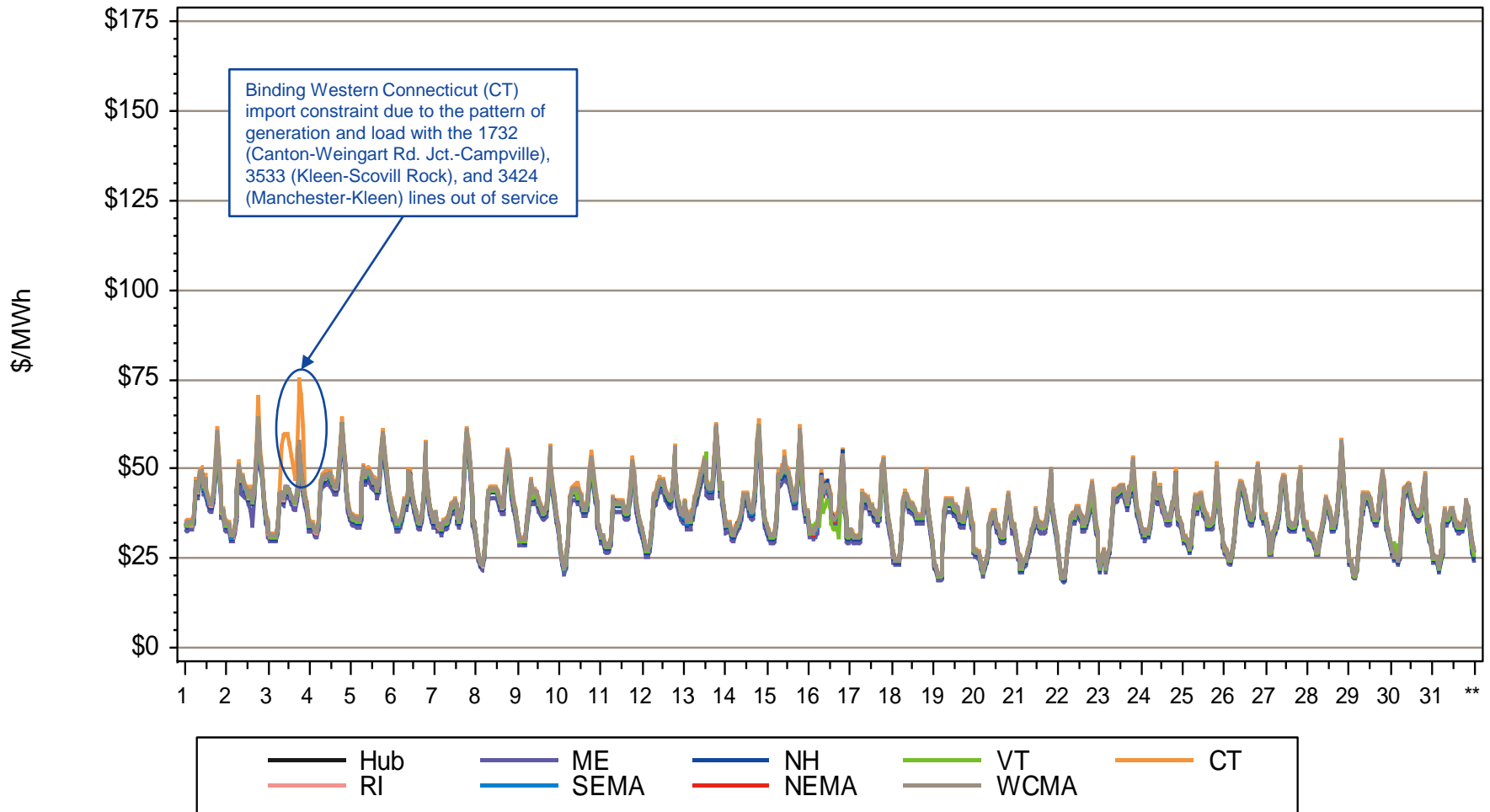


Demand



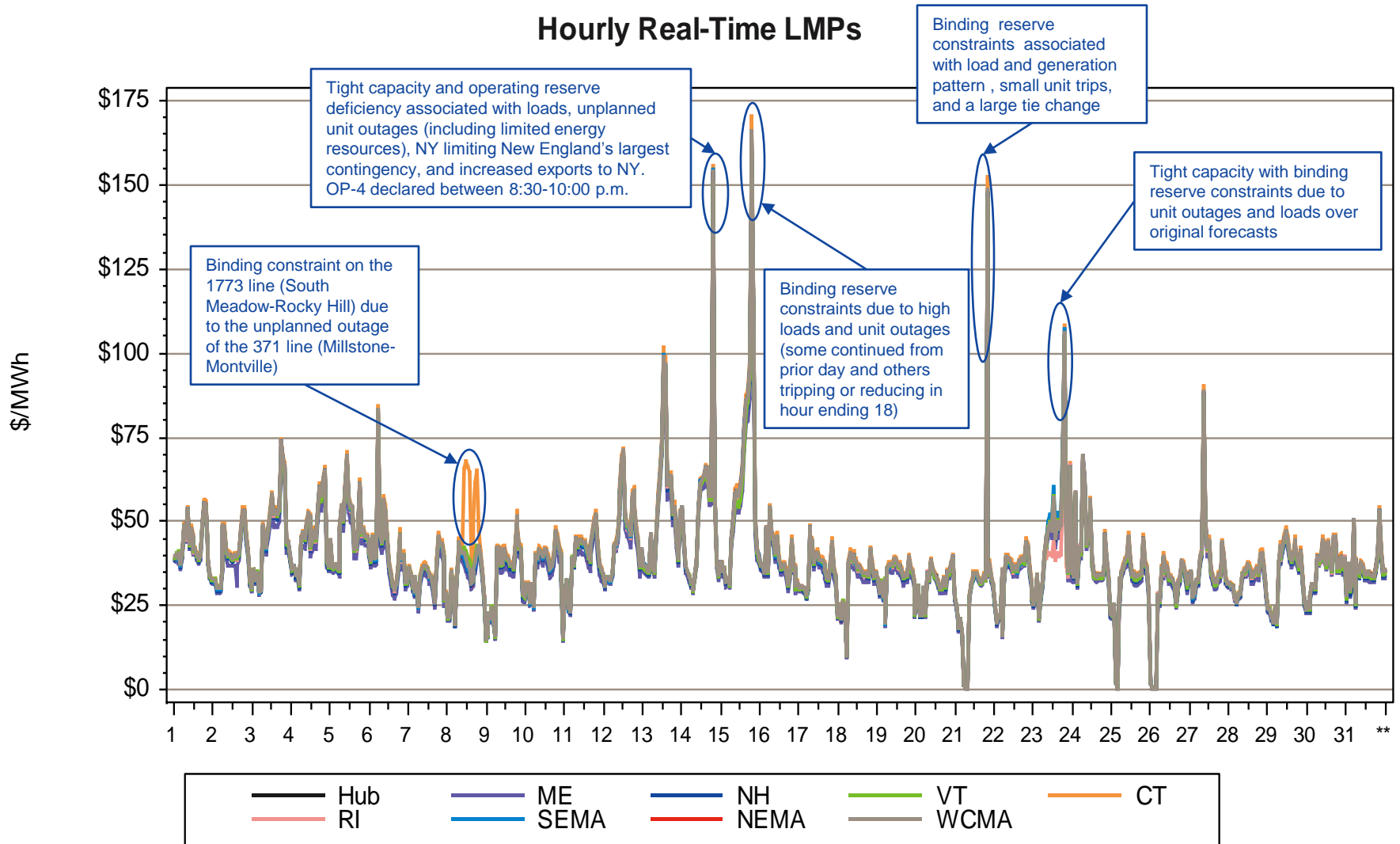
# Hourly DA LMPs, March 1-31, 2010

## Hourly Day-Ahead LMPs

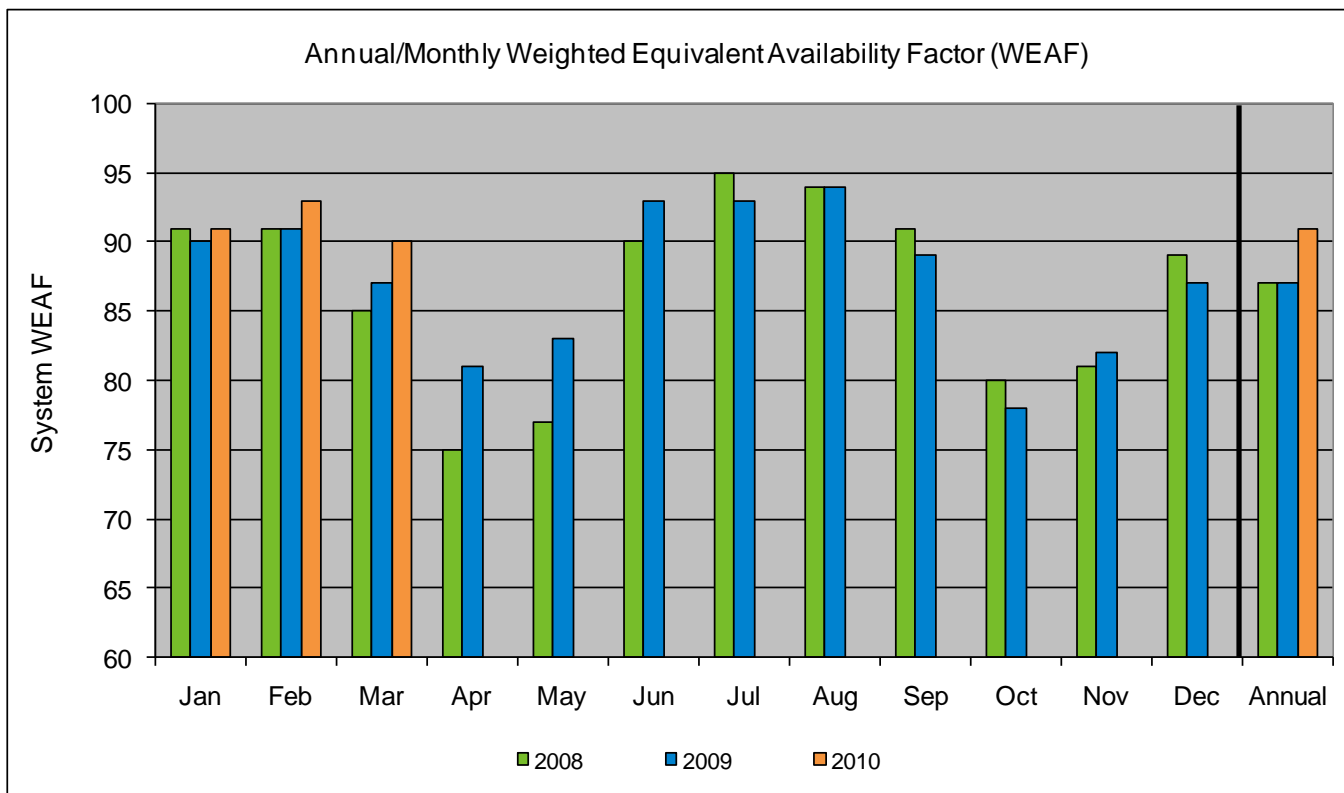


# Hourly RT LMPs, March 1-31, 2010

## 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										91	<b>2010</b>
												87	<b>2009</b>
												87	<b>2008</b>
												90	<b>2007</b>

# Back-up Detail

# Load Response

# Demand Response (as of April 1, 2010)

Ready To Respond*:			Approved**:	
Zone	Assets	Total MW	Assets	Total MW
CT	1,464	770.1	5	1.8
ME	132	521.3	1	0.4
NEMA	548	258.2	8	2.4
NH	203	102.6	0	0.0
RI	294	139.5	3	0.3
SEMA	397	135.8	1	0.2
VT	158	84.9	0	0.0
WCMA	524	266.9	5	1.8
Total	3,720	2,279.3	23	6.9

\*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 April 1, 2010)

Ready To Respond*:						Approved**:				
3,720 Assets 2,279.3 MW						23 Assets 06.9 MW				
Zone	Assets	RT Price	RT 30-Min	RT 2-Hour	Profiled	Assets	RT Price	RT 30-Min	RT 2-Hour	Profiled
CT	1,464	2.4	747.3	20.4	0.0	5	0.0	0.4	1.5	0.0
SWCT***	726	0.1	367.8	1.2	0.0	3	0.0	0.1	0.5	0.0
ME	132	0.0	398.5	111.8	11.0	1	0.0	0.4	0.0	0.0
NEMA	548	20.6	223.4	14.2	0.0	8	0.0	0.0	2.4	0.0
NH	203	4.5	92.7	5.4	0.0	0	0.0	0.0	0.0	0.0
RI	294	13.3	114.1	12.1	0.0	3	0.3	0.0	0.0	0.0
SEMA	397	8.2	110.8	16.8	0.0	1	0.0	0.2	0.0	0.0
VT	158	1.8	73.7	3.5	5.9	0	0.0	0.0	0.0	0.0
WCMA	524	14.7	216.4	35.9	0.0	5	0.0	0.4	1.4	0.0
Total	3,720	65.4	1,977.0	220.0	16.9	23	0.3	1.4	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

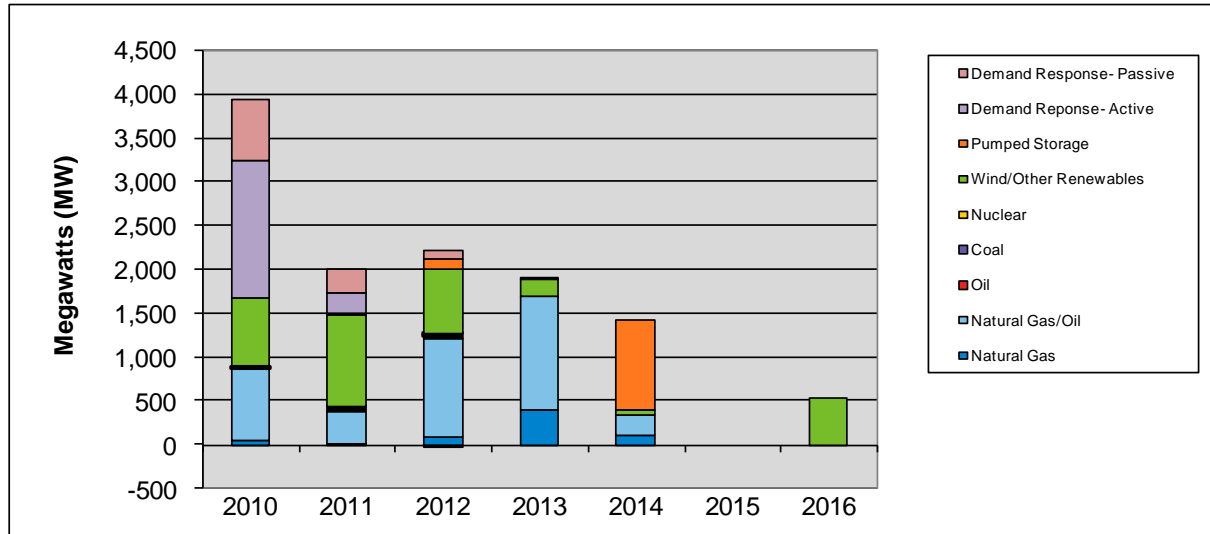
# New Generation

# New Generation Update

- No new generation projects have applied for interconnection study since the March update
- Three projects withdrew from the Queue and one project went commercial, resulting in a net decrease in new generation projects of 680 MW
- In total, 86 generation projects are currently being tracked by the ISO, totaling approximately 9,200 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

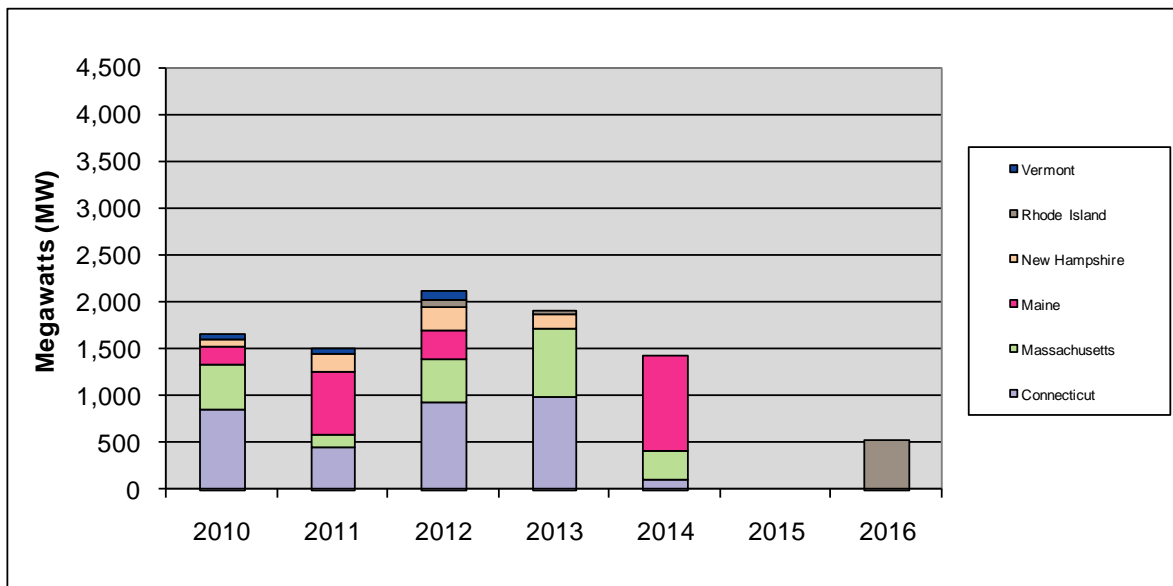


	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Demand Response - Passive	700	278	95	0	0	0	0	1,073	8.9
Demand Response - Active	1,579	221	-6	0	0	0	0	1,794	14.9
Pumped Storage	0	25	111	25	1,025	0	0	1,186	9.8
Wind & Other Renewables	772	1,041	734	189	50	0	536	3,322	27.6
Nuclear	0	45	0	0	0	0	0	45	0.4
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	838	372	1,124	1,287	244	0	0	3,865	32.1
Natural Gas	48	19	87	411	107	0	0	672	5.6
<b>Totals</b>	<b>3,954</b>	<b>2,014</b>	<b>2,211</b>	<b>1,912</b>	<b>1,426</b>	<b>0</b>	<b>536</b>	<b>12,053</b>	<b>100.0</b>

•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
<b>Vermont</b>	61	55	99	0	0	0	0	215	2.3
<b>Rhode Island</b>	0	0	61	29	0	0	536	626	6.8
<b>New Hampshire</b>	76	201	249	152	0	0	0	678	7.4
<b>Maine</b>	191	673	320	0	1,000	0	0	2,184	23.8
<b>Massachusetts</b>	492	125	463	736	319	0	0	2,135	23.2
<b>Connecticut</b>	855	461	930	995	107	0	0	3,348	36.4
<b>Totals</b>	<b>1,675</b>	<b>1,515</b>	<b>2,122</b>	<b>1,912</b>	<b>1,426</b>	<b>0</b>	<b>536</b>	<b>9,186</b>	<b>100.0</b>

# 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	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	11	672	1	2	10	670
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	32	2,868	4	180	28	2,688
<b>Total</b>	<b>86</b>	<b>9,186</b>	<b>11</b>	<b>1,405</b>	<b>75</b>	<b>7,781</b>

- 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	18	523	1	38	17	485
Intermediate	16	3,489	1	644	15	2,845
Peaker	20	2,306	5	543	15	1,763
Wind Turbine	32	2,868	4	180	28	2,688
<b>Total</b>	<b>86</b>	<b>9,186</b>	<b>11</b>	<b>1,405</b>	<b>75</b>	<b>7,781</b>

- 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	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	11	672	1	9	4	605	6	58	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	32	2,868	0	0	0	0	0	0	32	2,868
<b>Total</b>	<b>86</b>	<b>9,186</b>	<b>18</b>	<b>523</b>	<b>16</b>	<b>3,489</b>	<b>20</b>	<b>2,306</b>	<b>32</b>	<b>2,868</b>

# Reliability Costs

# Net Commitment Period Compensation (NCPC) Operating Costs

# What are Daily NCPC Payments?

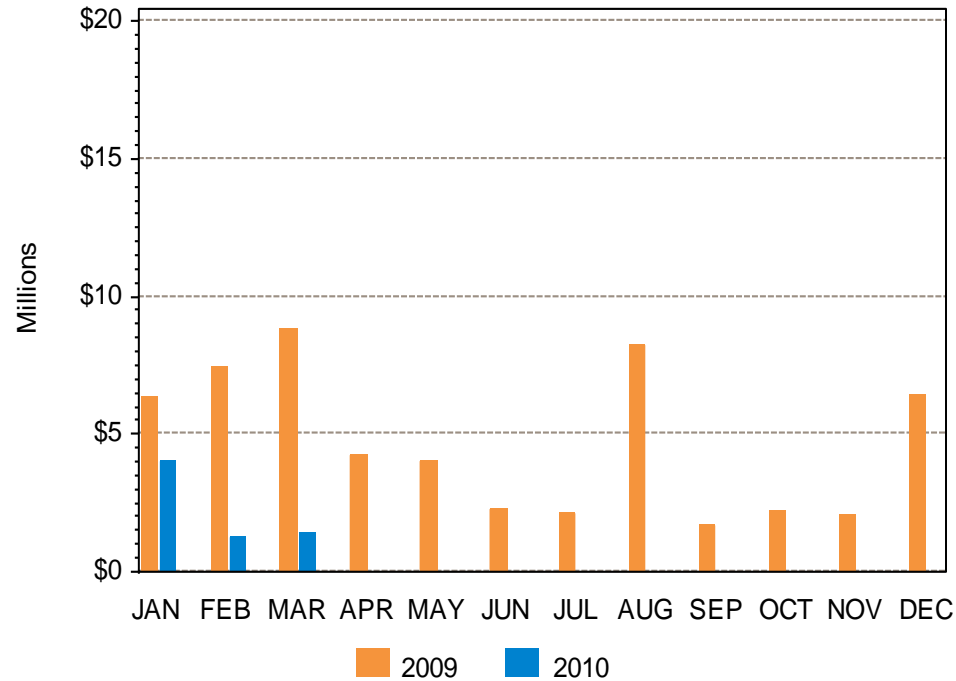
- “Make-whole” payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource’s offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day
- Typically, this is the result of some out-of-merit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

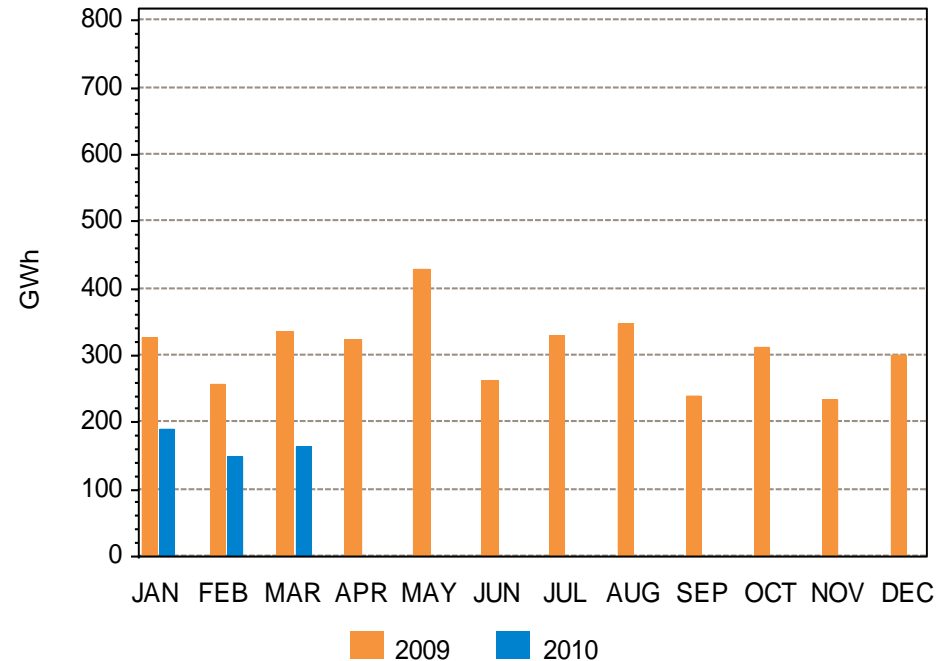
<b>Voltage NCPC Payments</b>	Reliability costs paid to resources operated by the ISO-NE to provide voltage control in specific locations
<b>Distribution NCPC Payments</b>	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
<b>1<sup>st</sup> Contingency NCPC Payments</b>	Reliability costs paid to eligible resources that are not providing 2 <sup>nd</sup> Contingency, Voltage, or Distribution requirements. These resources may have been providing first contingency coverage (system-wide or locally)
<b>2<sup>nd</sup> Contingency NCPC Payments</b>	Reliability costs paid to resources providing adequate capacity in constrained areas to respond to a local second contingency. They are committed based on 2 <sup>nd</sup> Contingency protocols
<b>Delisted Units</b>	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

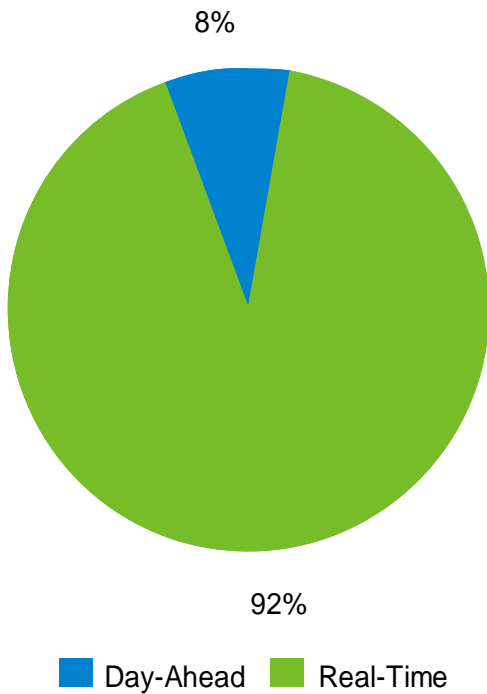


**Note:**

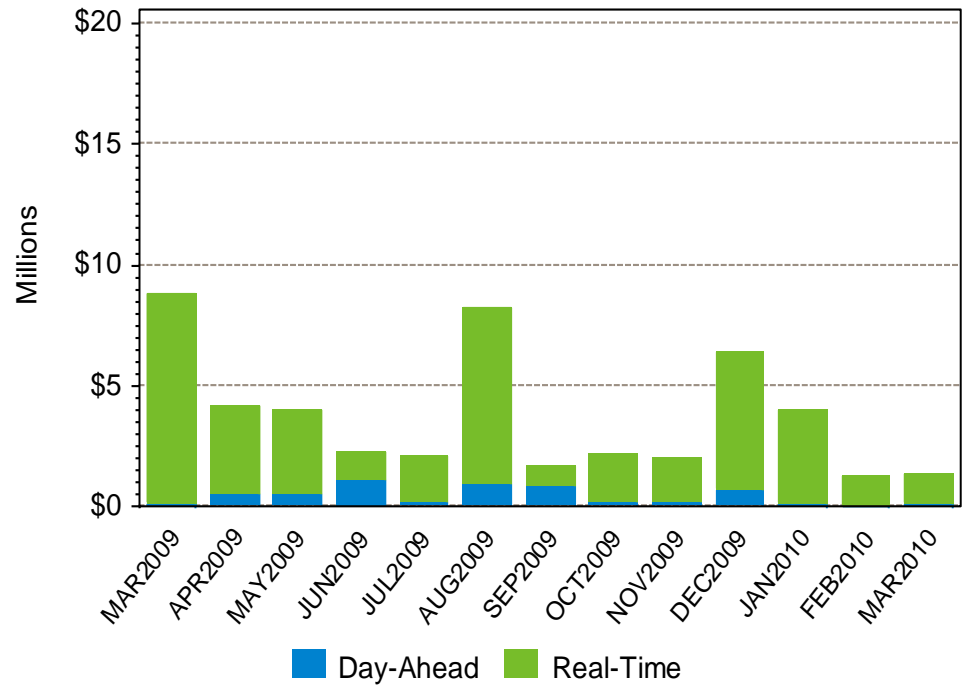
- Overall Reliability Cost MWh includes out of merit DA and RT 1<sup>st</sup> Contingency, 2<sup>nd</sup> Contingency, Voltage, and RT Distribution components.
- Energy includes daily totals of cleared DA energy and RT energy from resources receiving NCPC payments.

# DA and RT NCPC Payments

MAR-10 Total = \$1.34 M

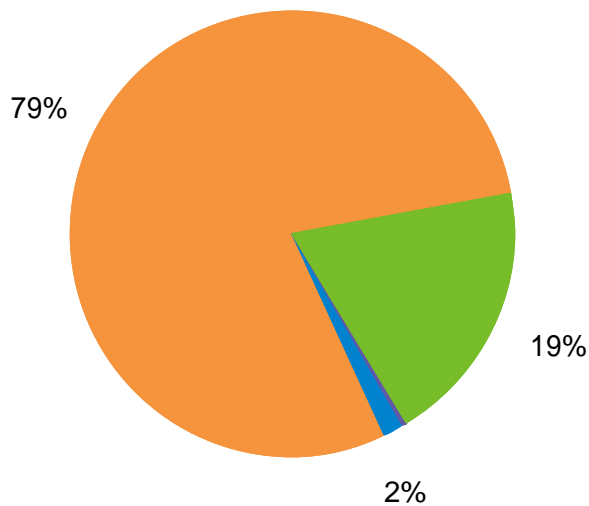


Last 13 Months



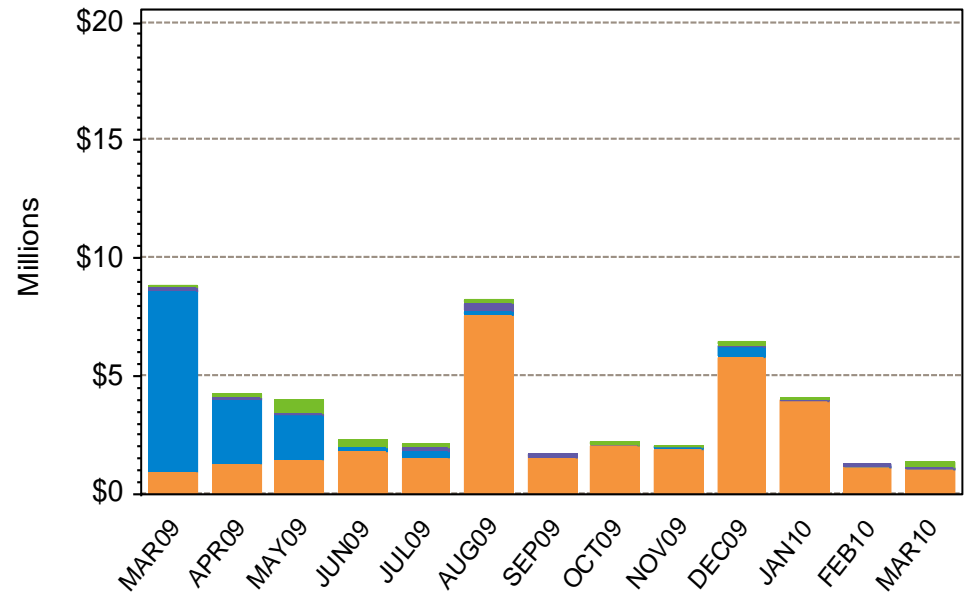
# NCPC Payments by Type

MAR-10 Total = \$1.34 M



■ 1st C    ■ 2nd C  
■ Distrib    ■ Voltage

Last 13 Months

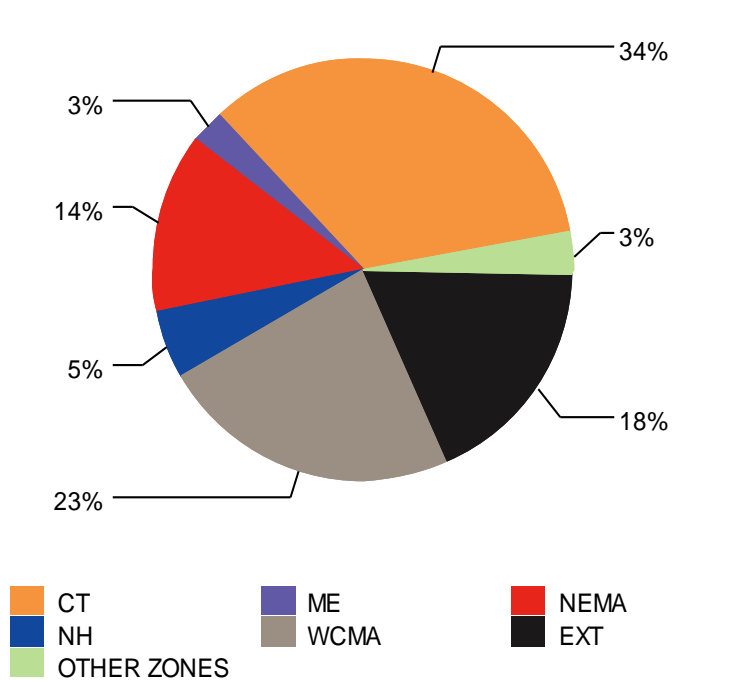


■ 1st C    ■ 2nd C  
■ Voltage    ■ Distrib

1<sup>st</sup> C – First Contingency  
 2<sup>nd</sup> C – Second Contingency  
 Distrib – Distribution  
 Voltage – Voltage Support

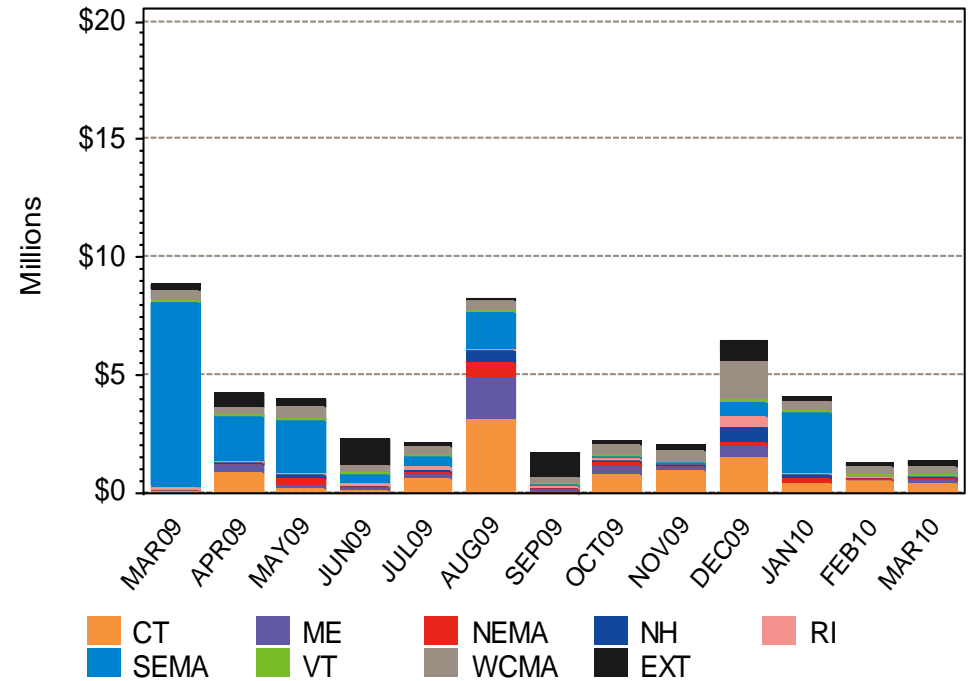
# NCPC Payments by Location

MAR-10 Total = \$1.34 M



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

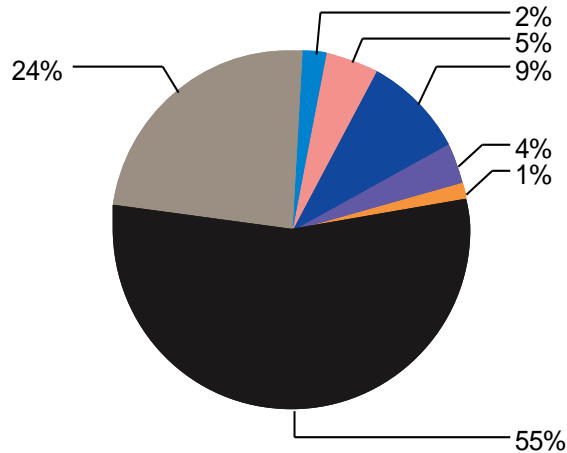
Last 13 Months



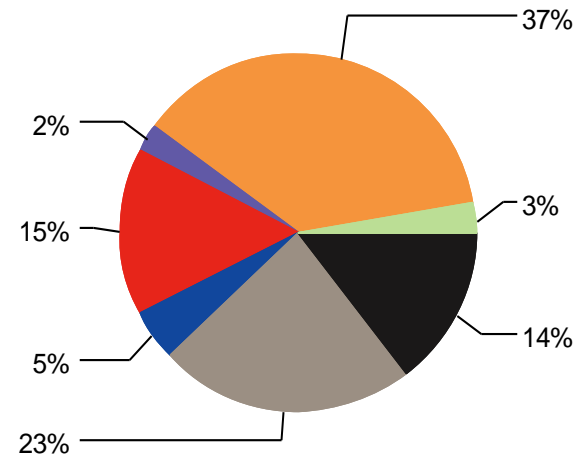
VT – Vermont Region  
 SEMA – Southeast Massachusetts Region  
 WCMA – Western/Central Massachusetts Region  
 NEMA – Northeast Massachusetts Region  
 EXT – External Locations

# DA and RT NCPC Payments by Location

MAR-10 Day-Ahead Total = \$0.11 M

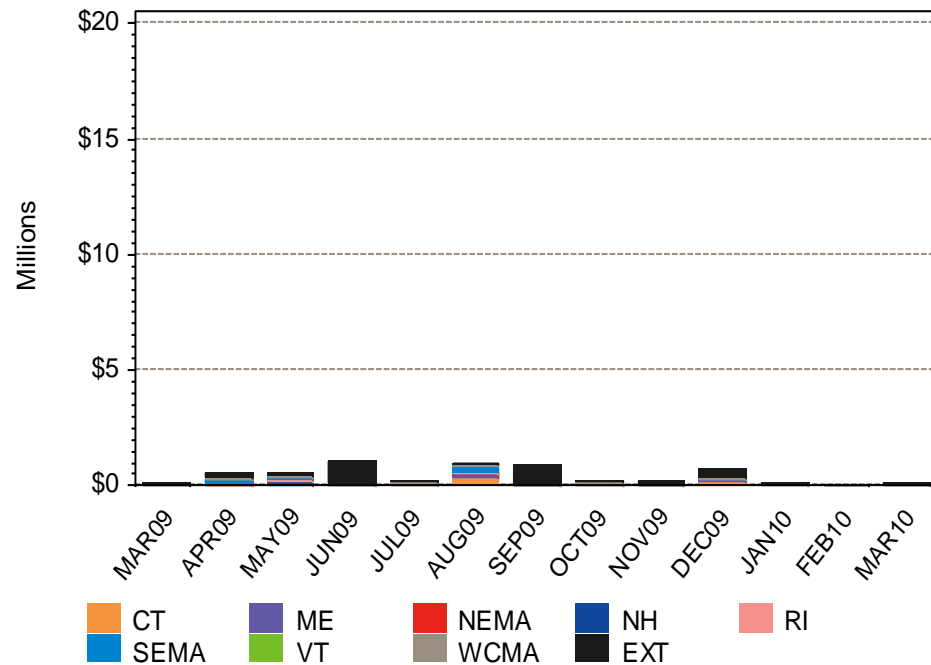


MAR-10 Real-Time Total = \$1.23 M

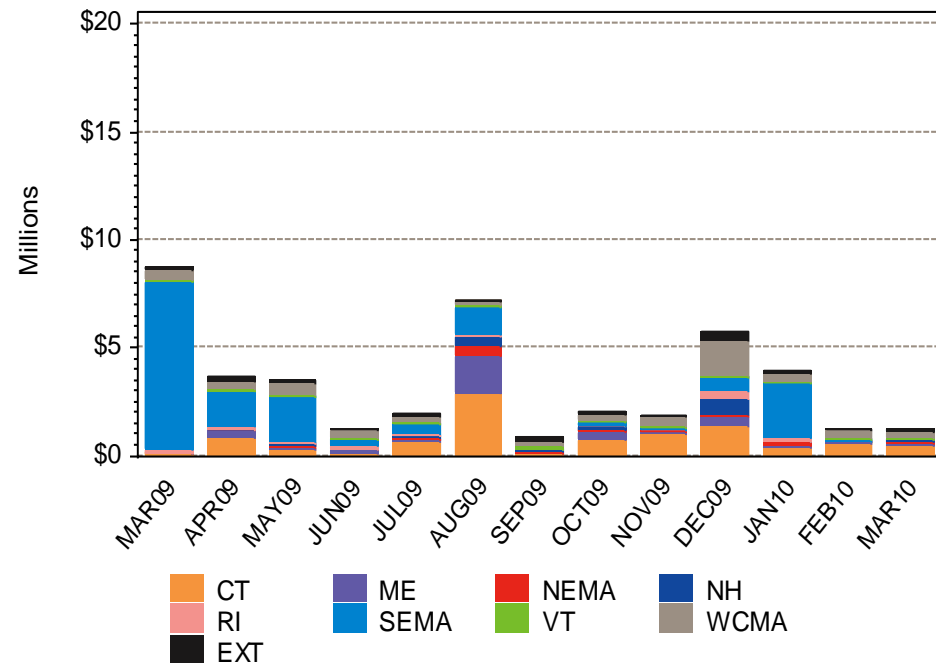


# DA and RT NCPC Payments by Location, Last 13 Months

## Day-Ahead, Last 13 Months

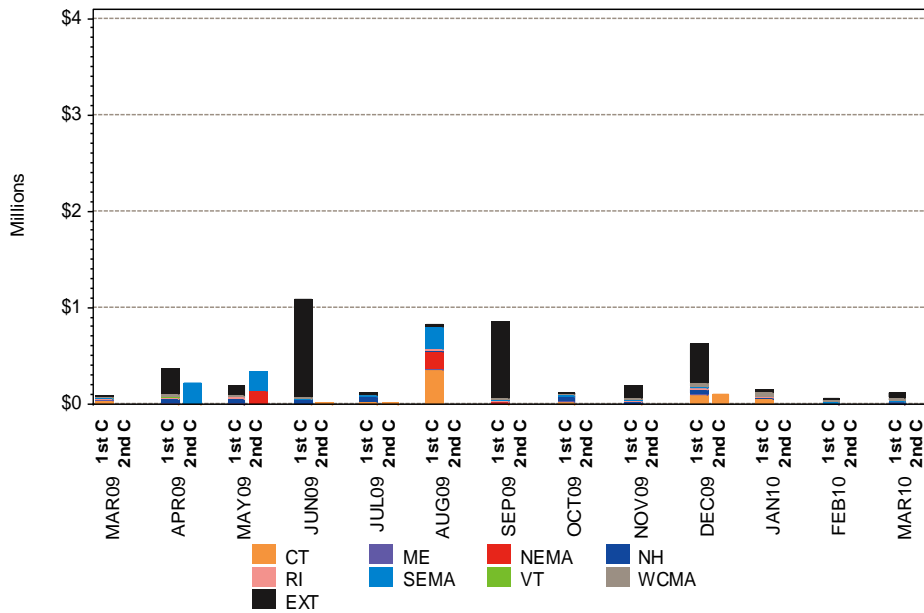


## Real-Time, Last 13 Months

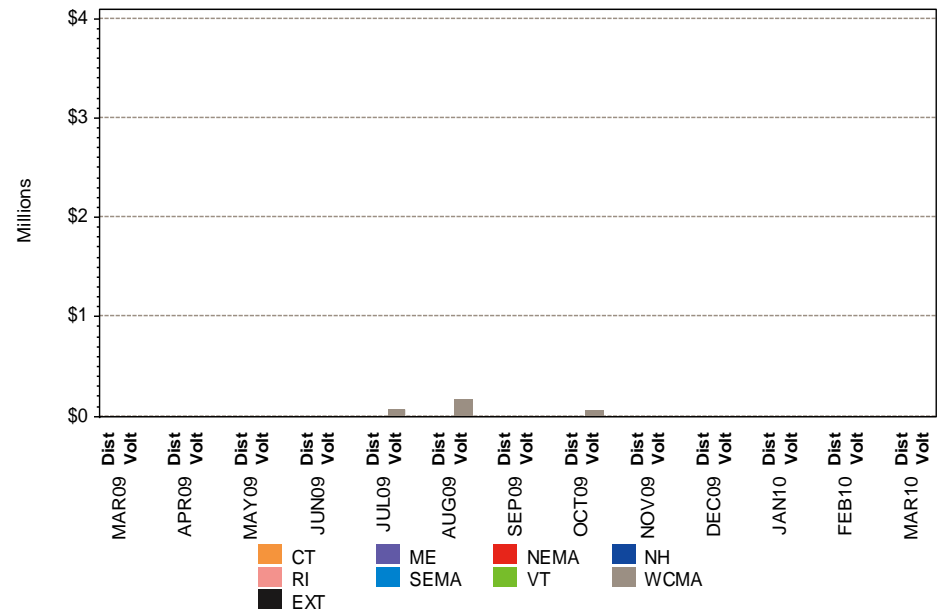


# DA NCPC Payments by Type and Location

## First and Second Contingency Payments

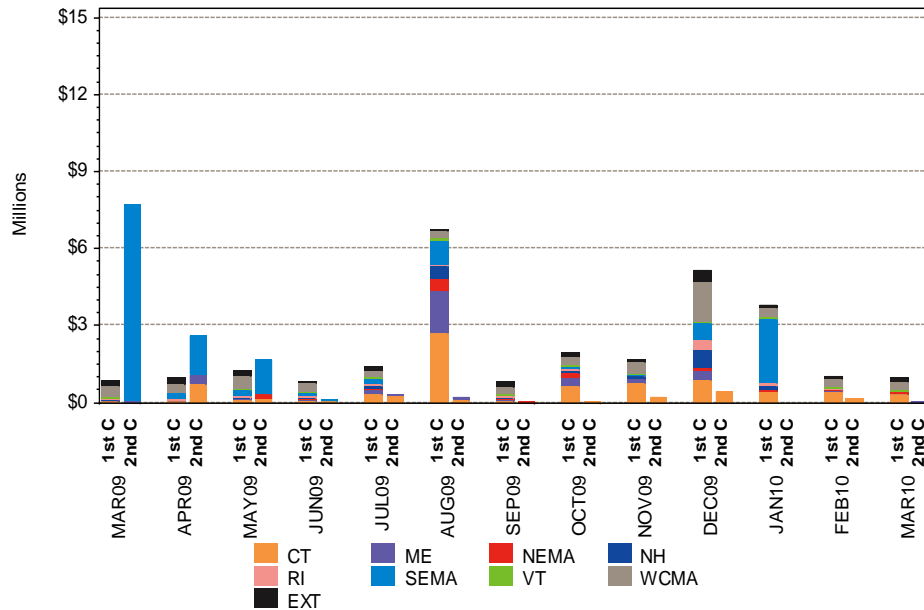


## Voltage and Distribution Payments

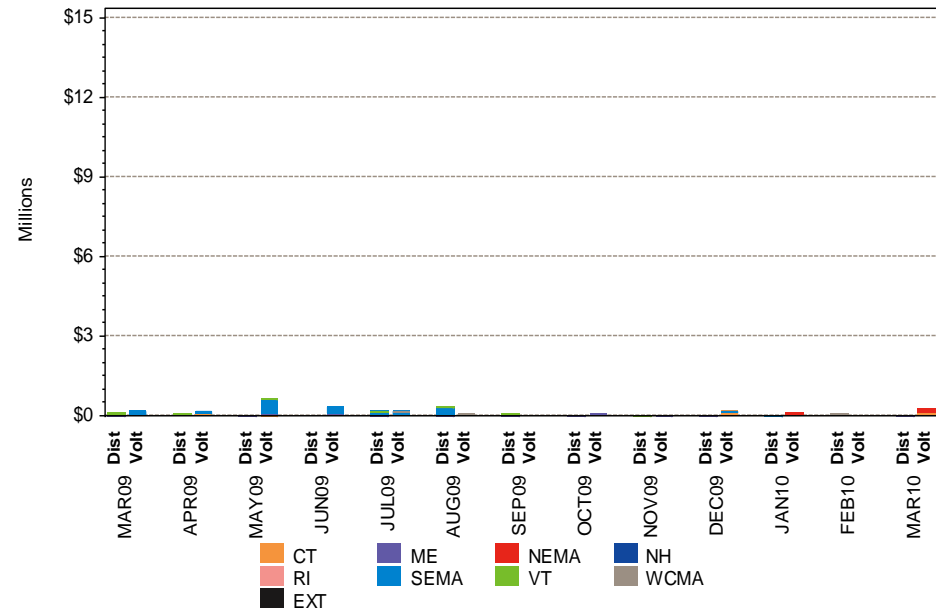


# RT NCPC Payments by Type and Location

## First and Second Contingency Payments

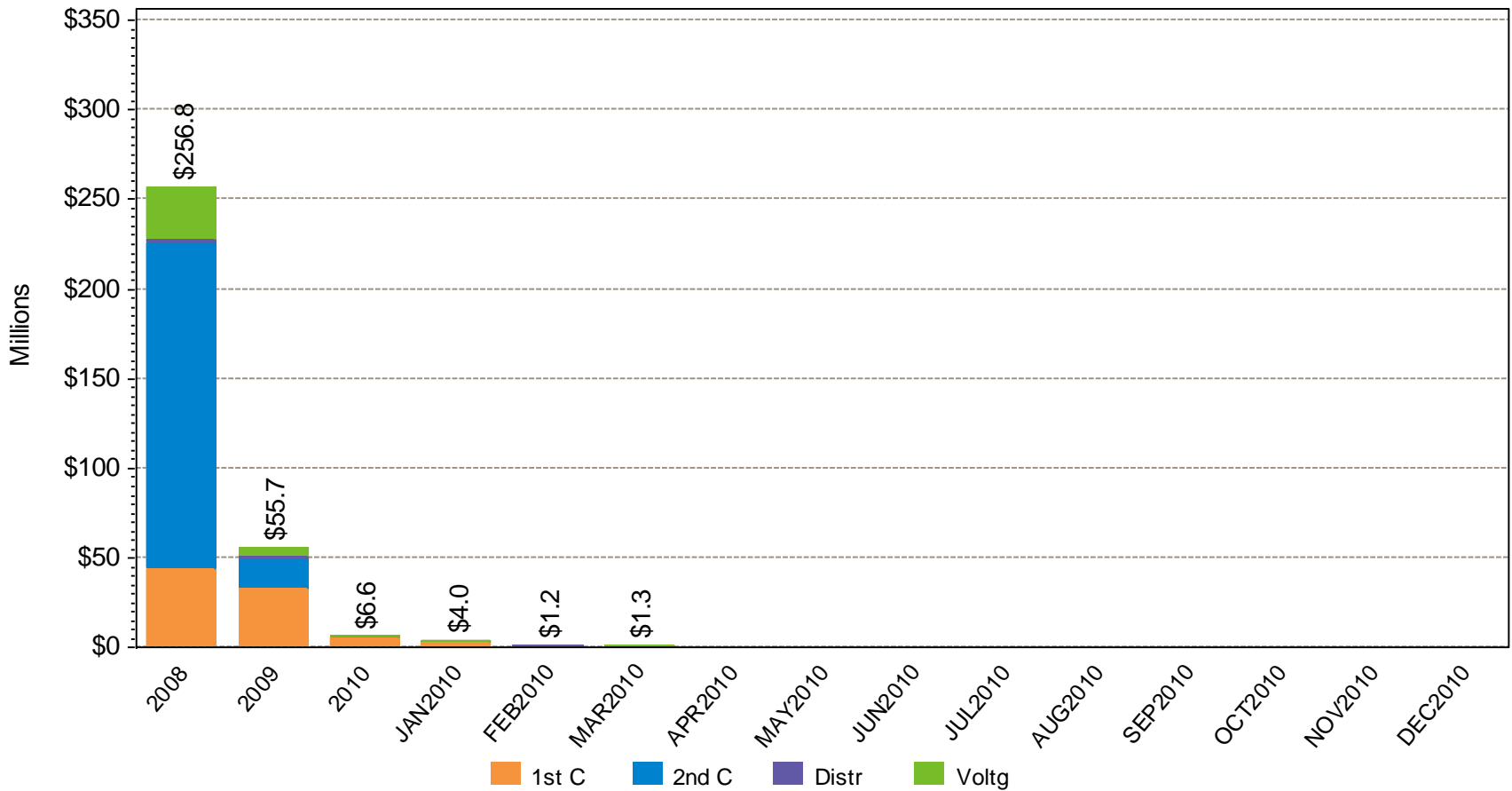


## Voltage and Distribution Payments



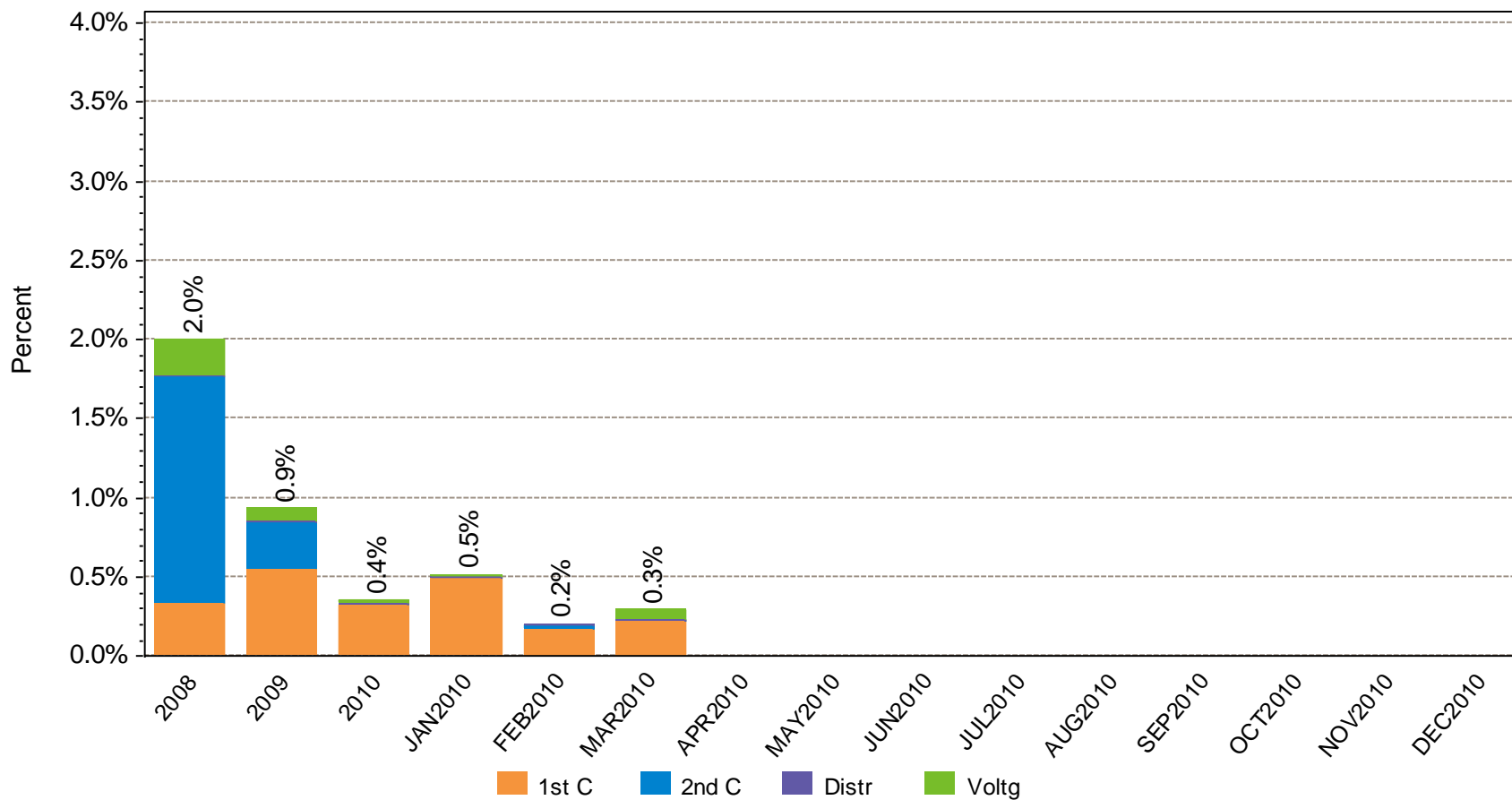
# NCPC Payments by Type

Payments by Type of NCPC



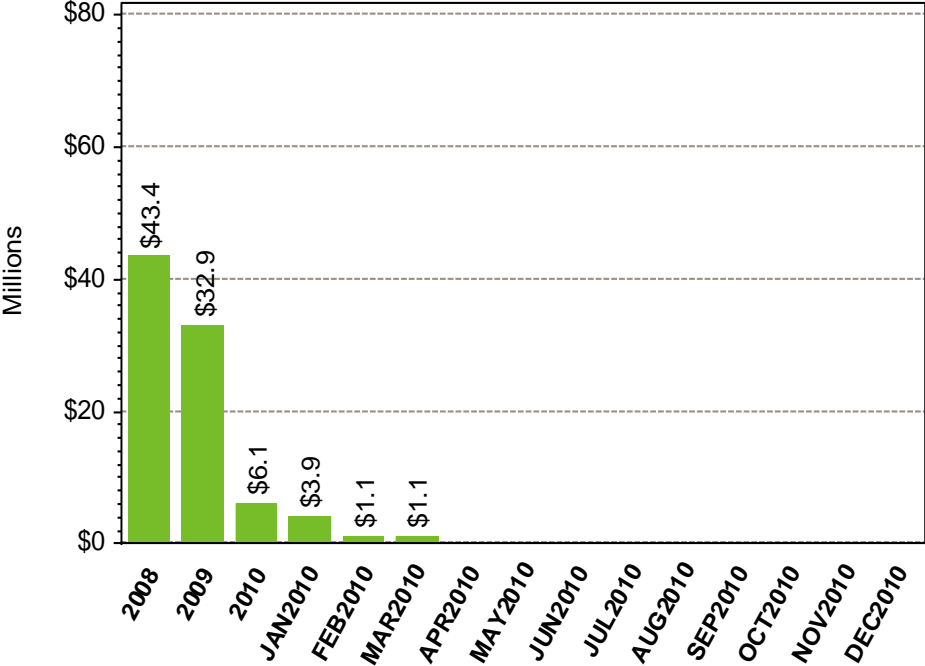
# NCPC Payments by Percent of Energy Market

NCPC By Type as Percent of Energy Market

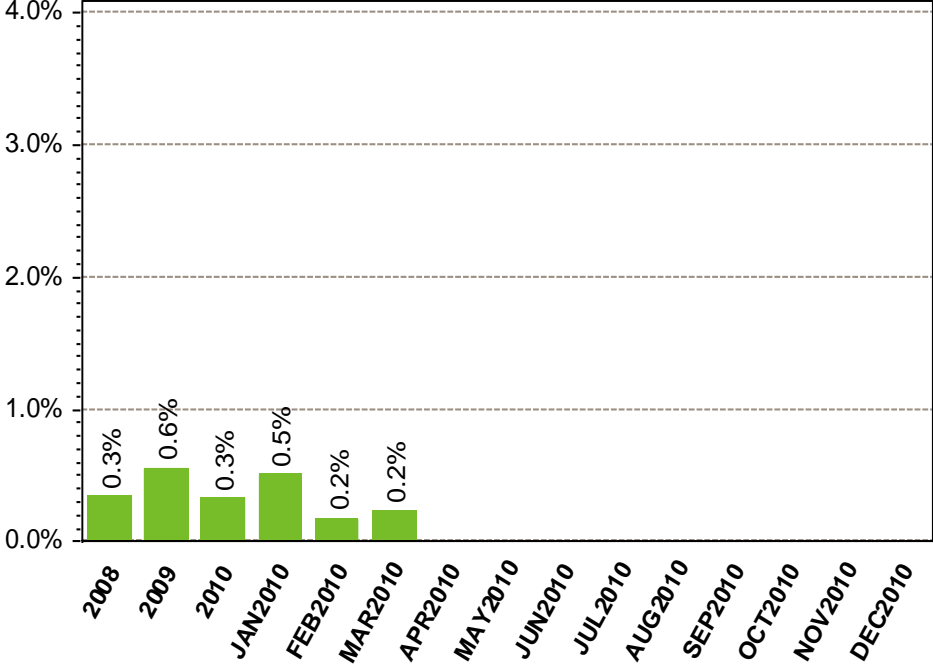


# First Contingency NCPC Payments

Value of Payments



% of Energy Market Value

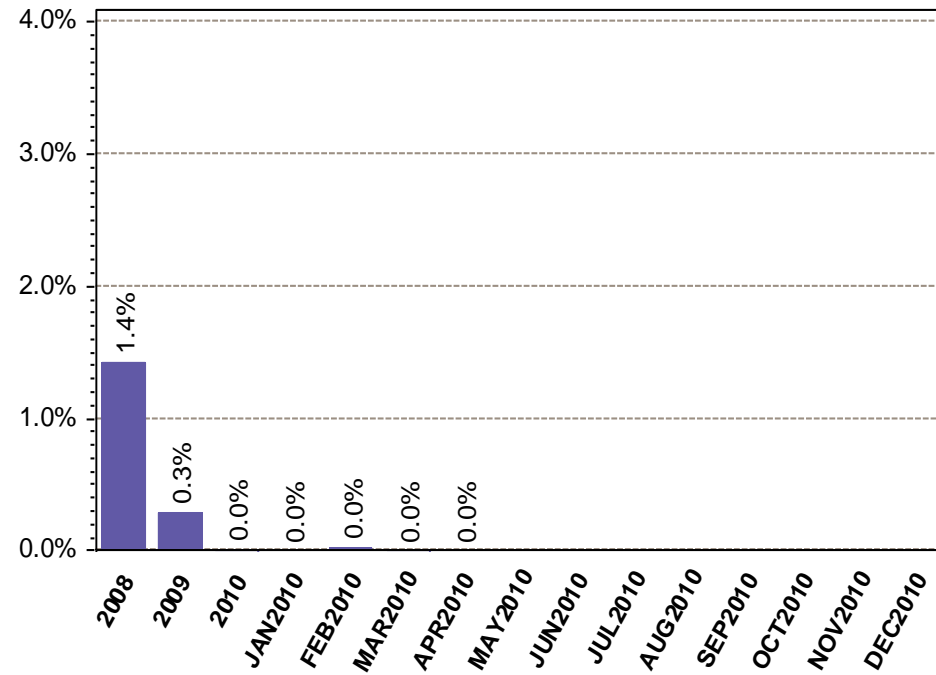
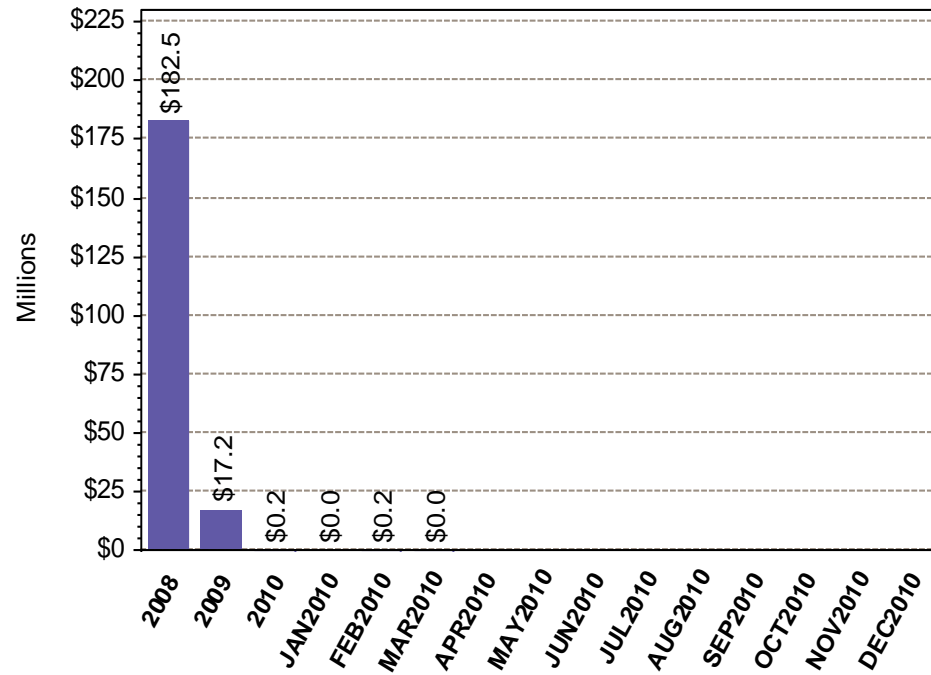


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

# Second Contingency NCPC Payments

Value of Payments

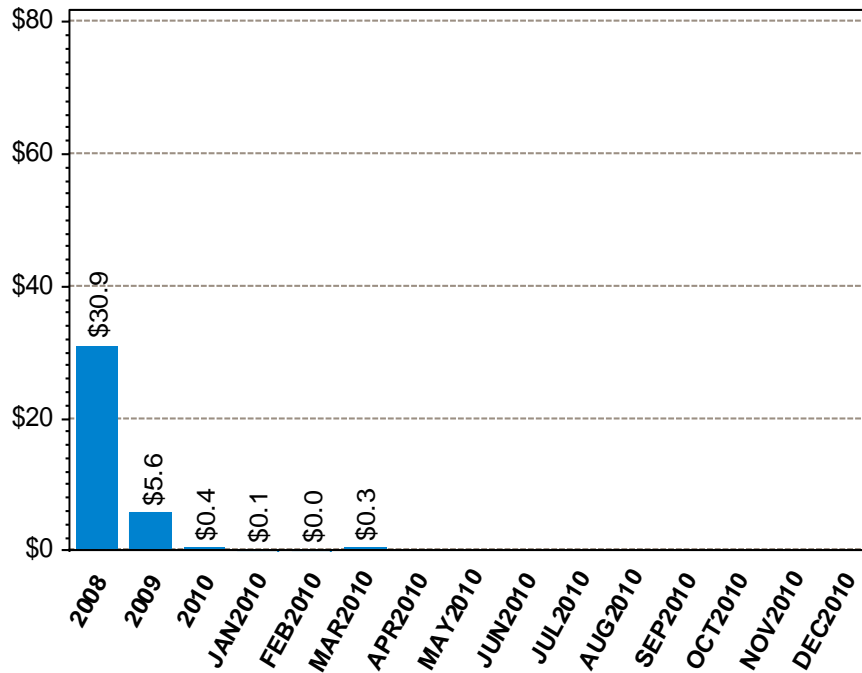
% of Energy Market Value



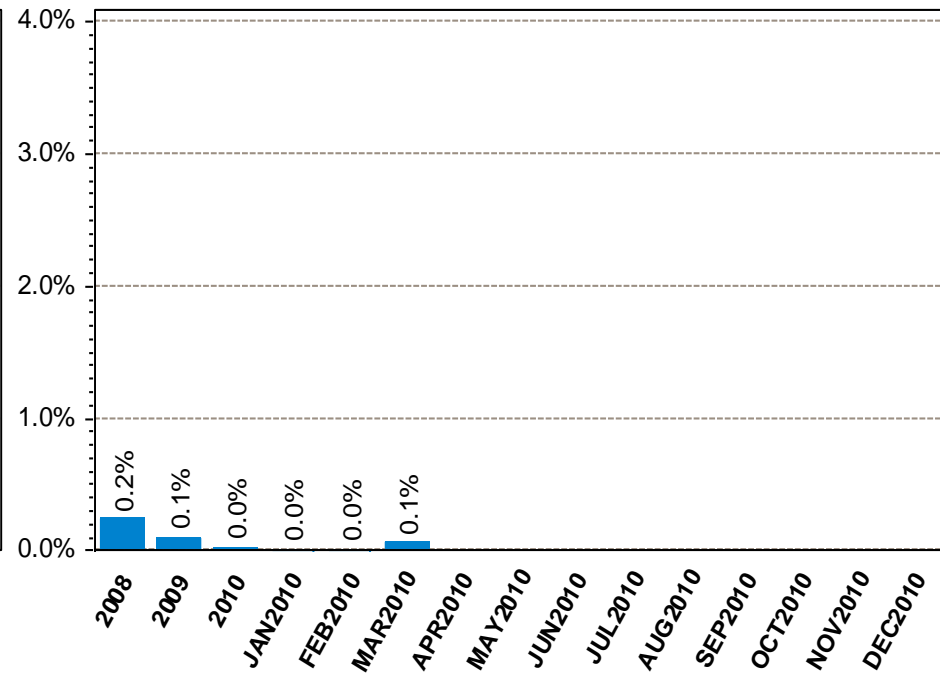
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

# 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

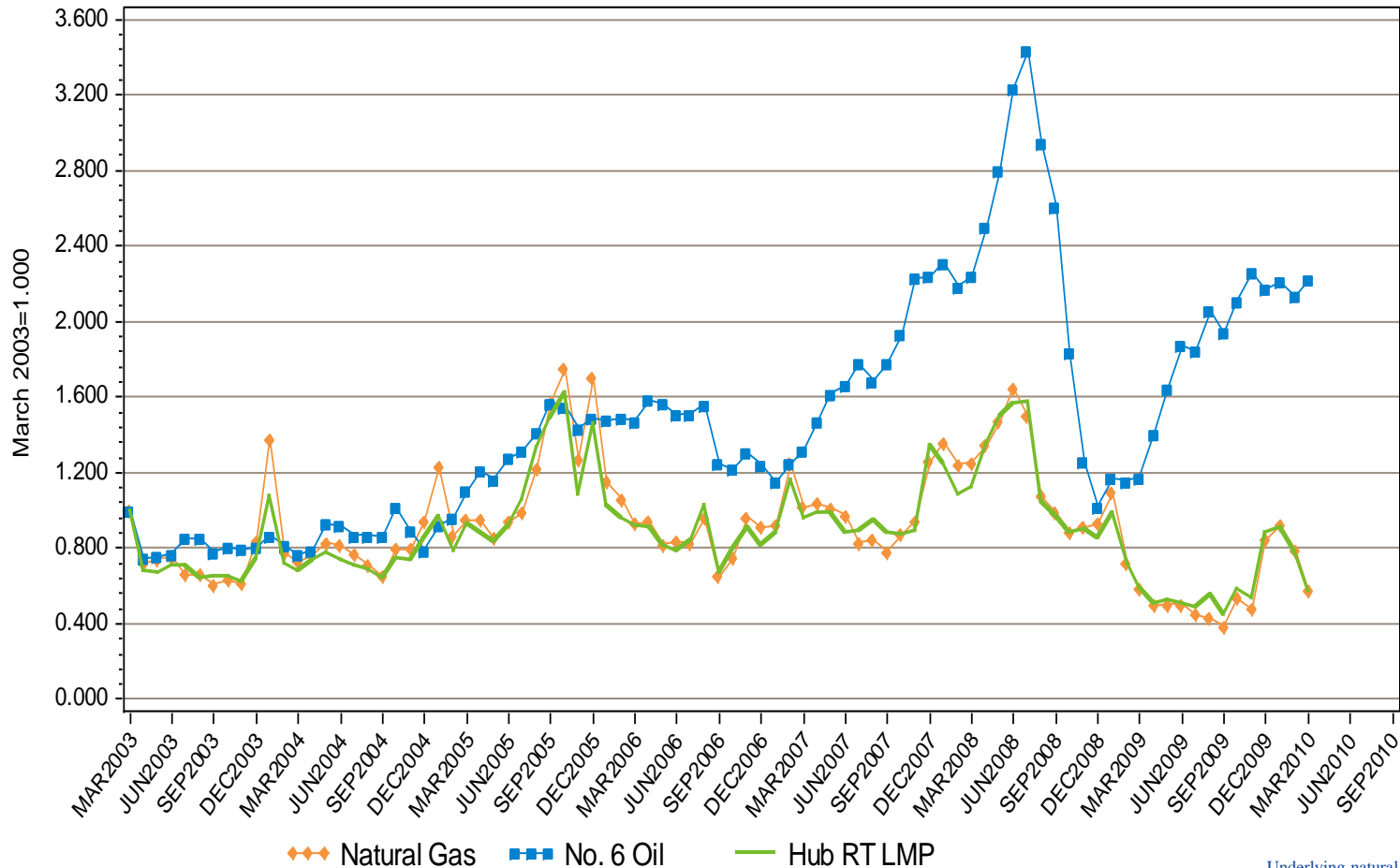
The following slides outline:

- 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%
March-09	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$41.95	\$43.43	\$40.18	\$41.35	\$42.38	\$41.75	\$42.49	\$42.83	\$42.22
Real-Time	\$40.40	\$41.31	\$38.41	\$39.63	\$40.47	\$40.07	\$40.47	\$41.04	\$40.53
RT Delta %	-3.7%	-4.9%	-4.4%	-4.2%	-4.5%	-4.0%	-4.8%	-4.2%	-4.0%
March-10	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$37.77	\$39.30	\$36.09	\$37.32	\$37.91	\$37.87	\$38.01	\$38.47	\$38.07
Real-Time	\$38.86	\$40.27	\$37.06	\$38.35	\$38.95	\$38.76	\$39.12	\$39.45	\$39.17
RT Delta %	2.9%	2.5%	2.7%	2.7%	2.7%	2.4%	2.9%	2.5%	2.9%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-10.0%	-9.5%	-10.2%	-9.7%	-10.5%	-9.3%	-10.6%	-10.2%	-9.8%
Yr over Yr RT	-3.8%	-2.5%	-3.5%	-3.2%	-3.8%	-3.2%	-3.3%	-3.9%	-3.4%

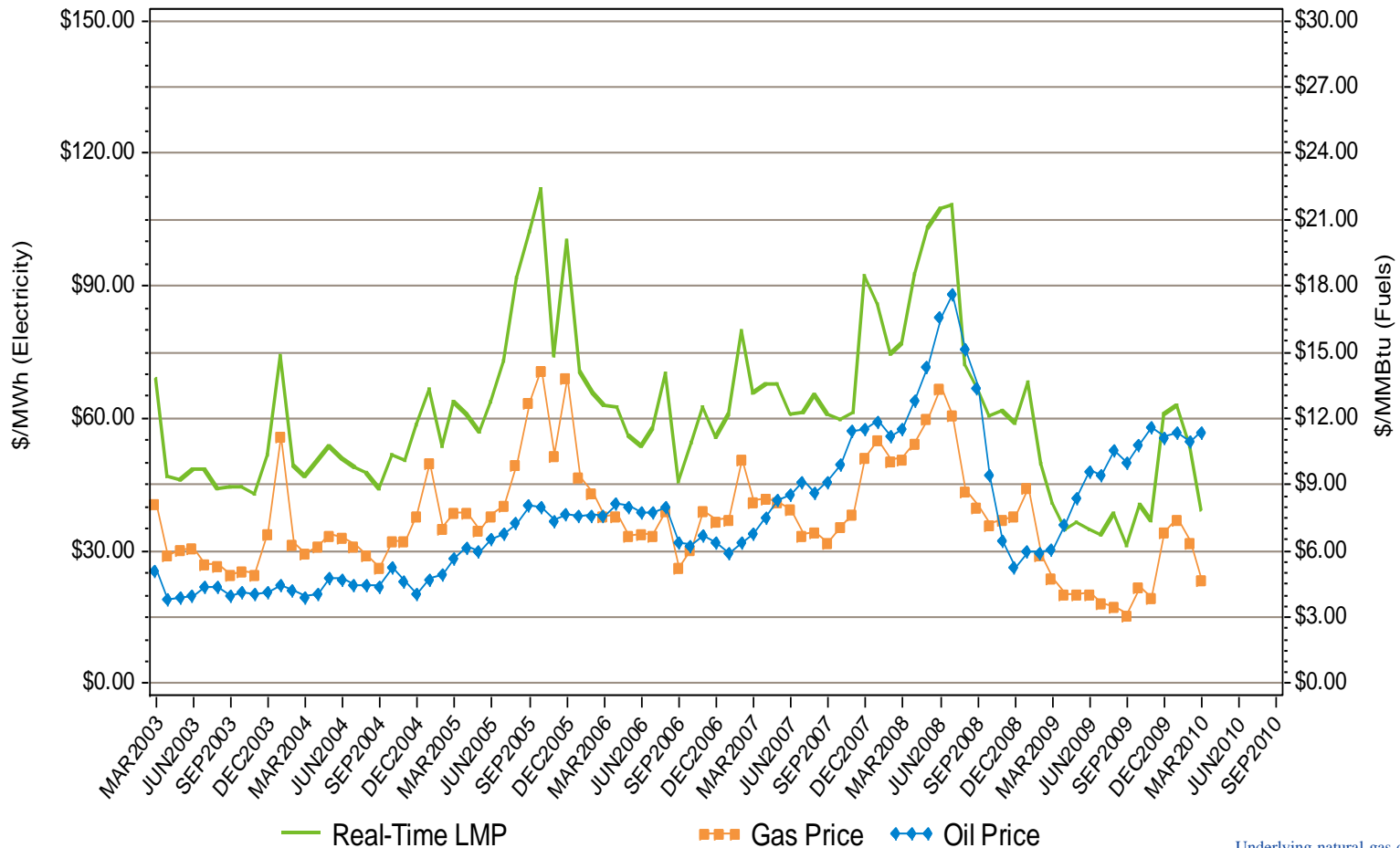
# Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:



# Monthly Average Fuel Price and RT Hub LMP



Underlying natural gas data furnished by:



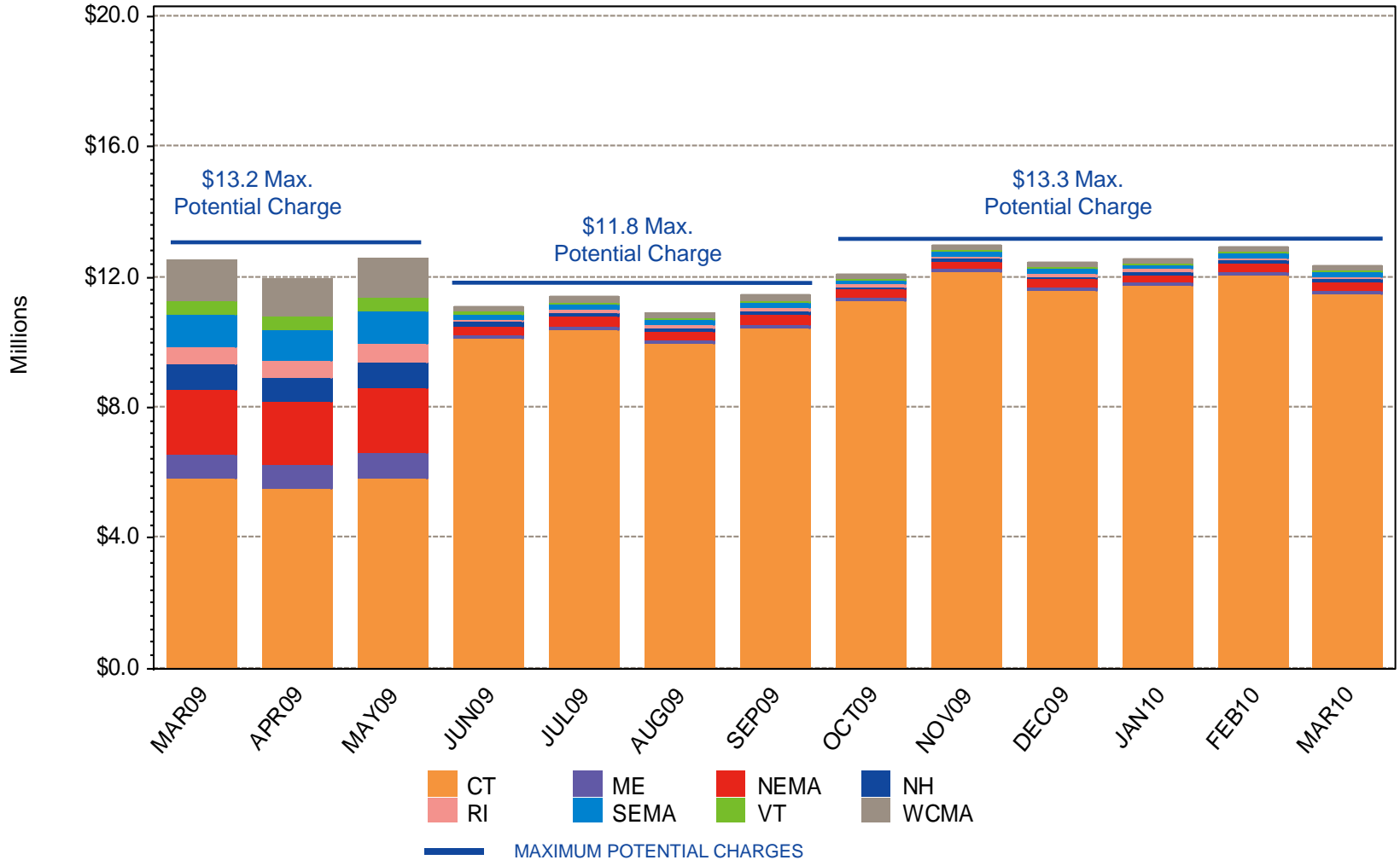
# Reserve Market Results – March 2010

- Maximum potential Forward Reserve Market payments of \$13.3M were reduced by credit reductions of \$531K, failure-to-reserve penalties of \$400K and failure-to-activate penalties of \$0, resulting in a net payout of \$12.3M or 93% of maximum
  - Rest of System: \$1.50M/\$1.68M (89%)
  - Southwest Connecticut: \$3.96M/\$4.22M (94%)
  - Connecticut: \$6.88M/\$7.37M (93%)
  - NEMA: n/a
- \$1.03M 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 March

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

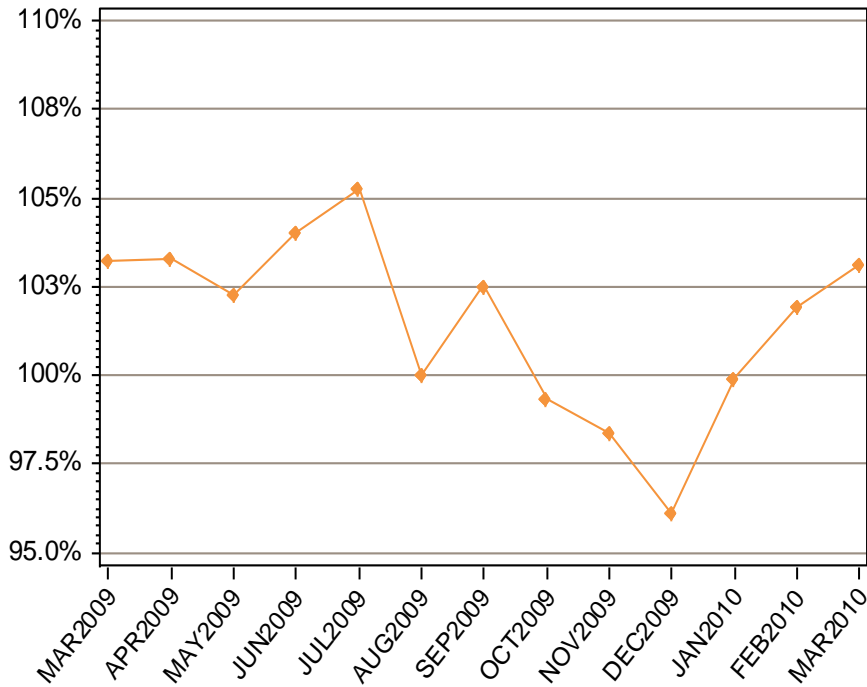
# LFRM Charges to Load by Load Zone (\$)

LFRM Charges by Zone, Last 13 Months

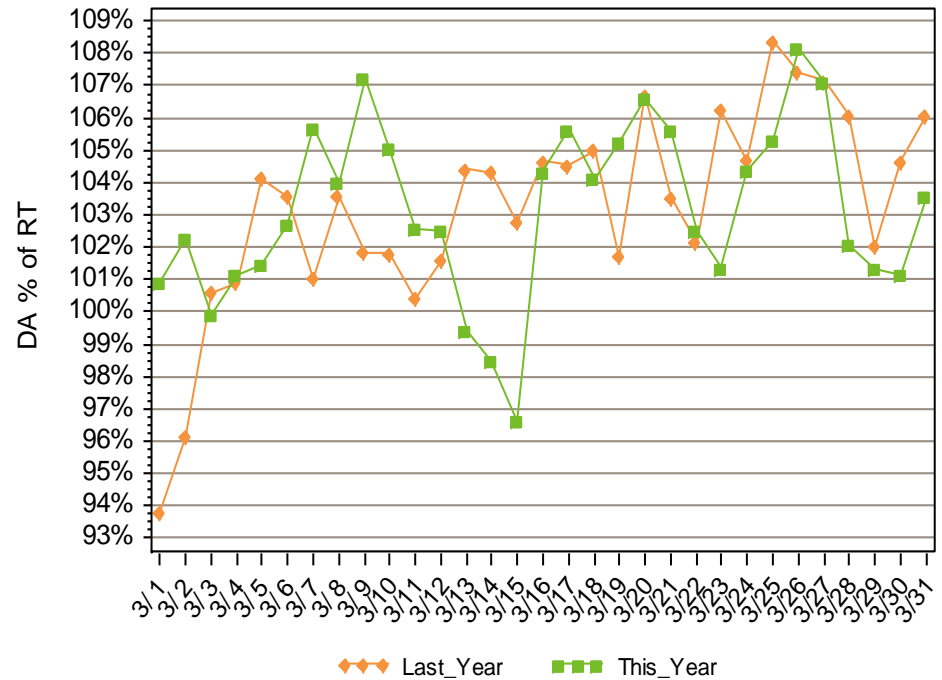


# DA Load Obligation Percent of RT Load Obligation

Monthly, Last 13 Months

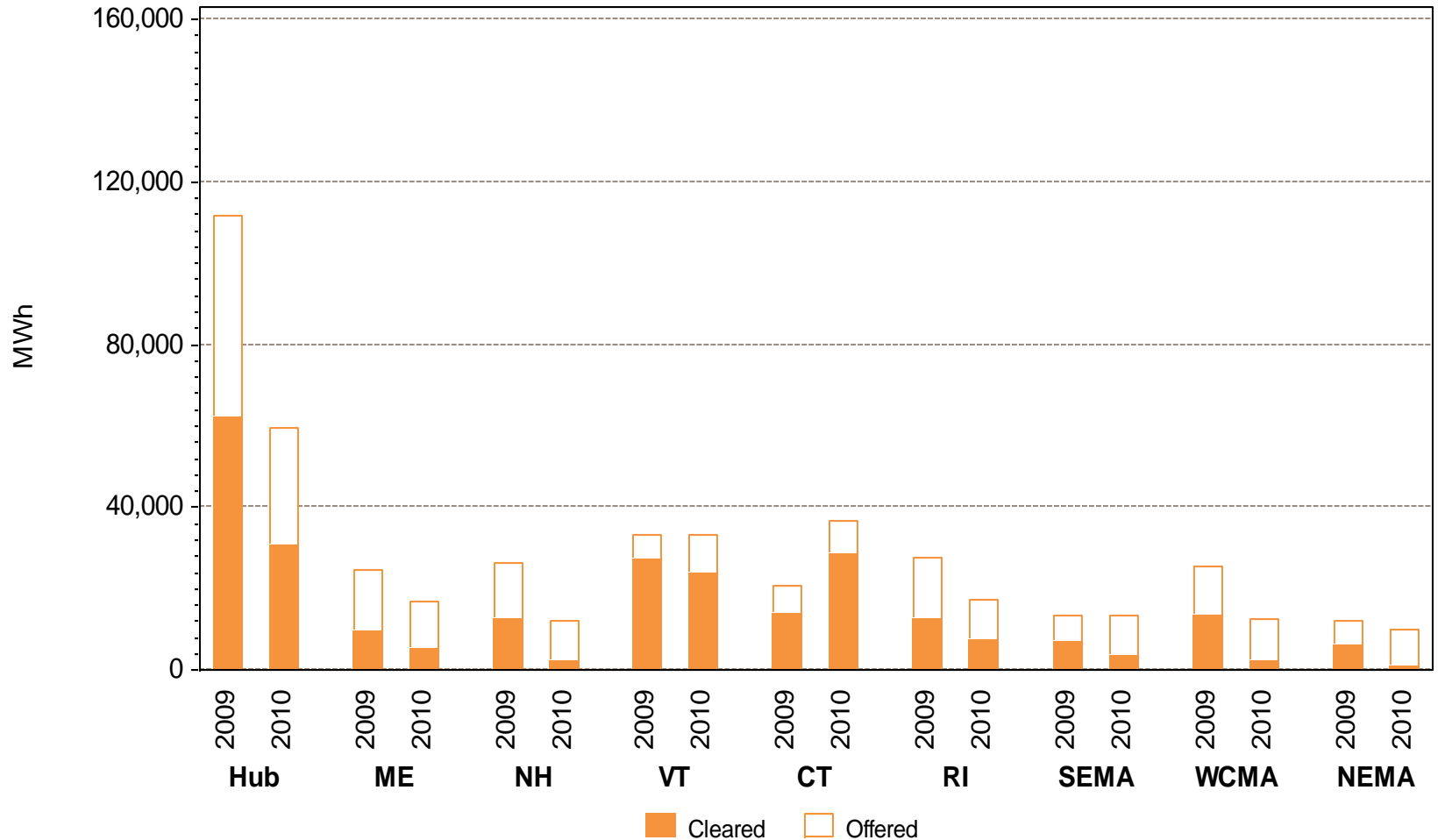


Daily, This Year vs. Last Year



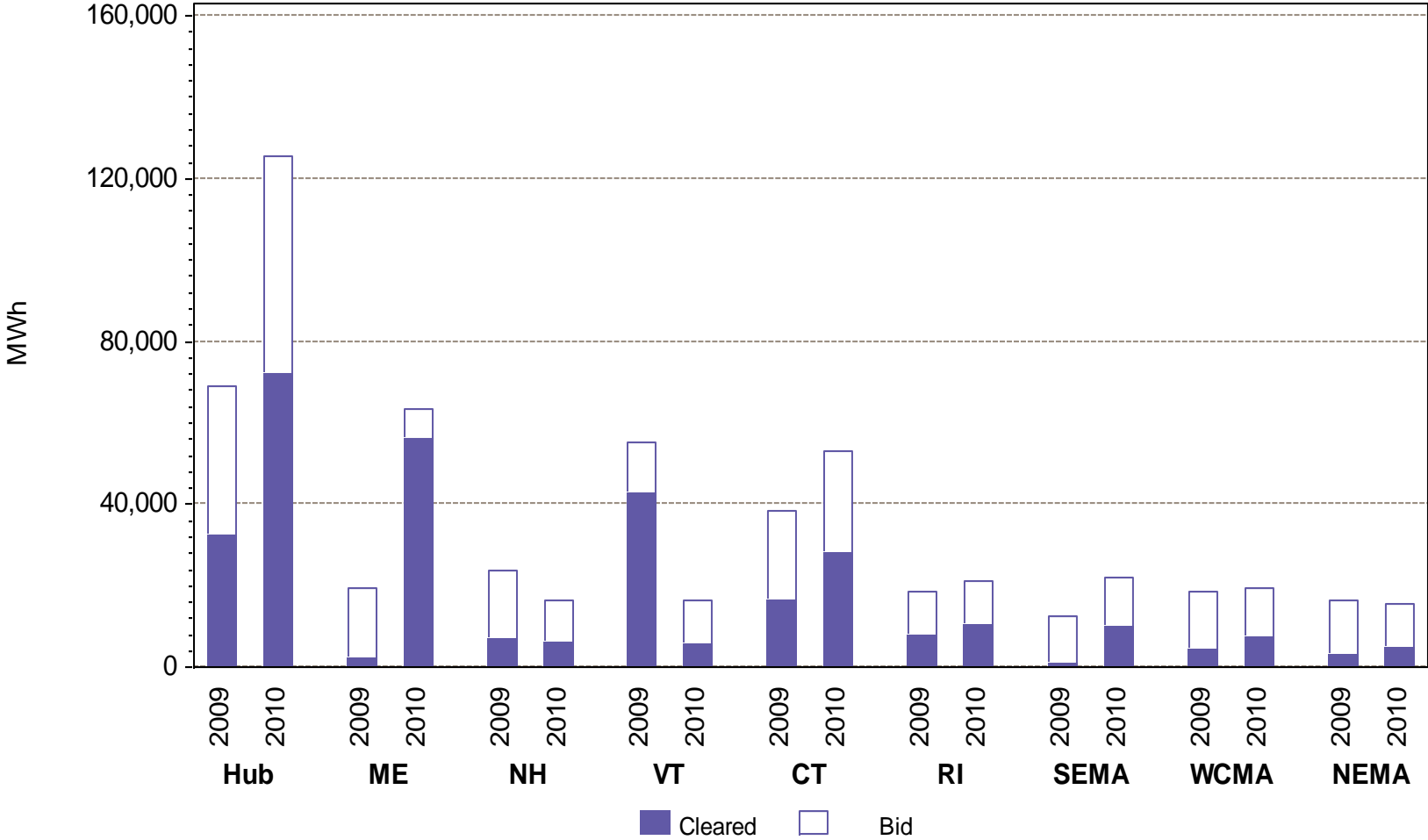
# Zonal Increment Offers and Cleared Amounts

March Monthly Totals by Zone



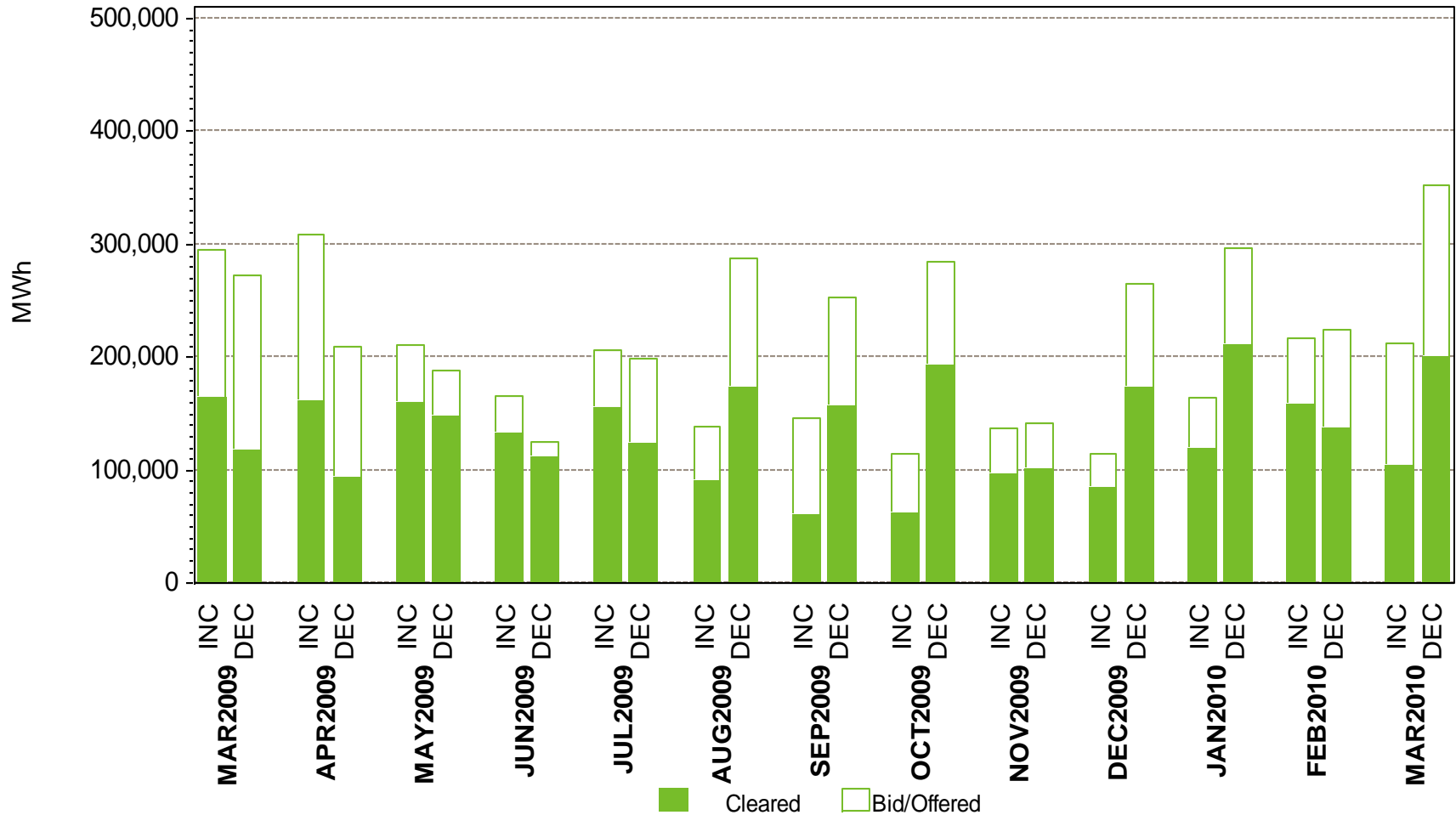
# Zonal Decrement Bids and Cleared Amounts

March Monthly Totals by Zone



# Total Increment Offers and Decrement Bids

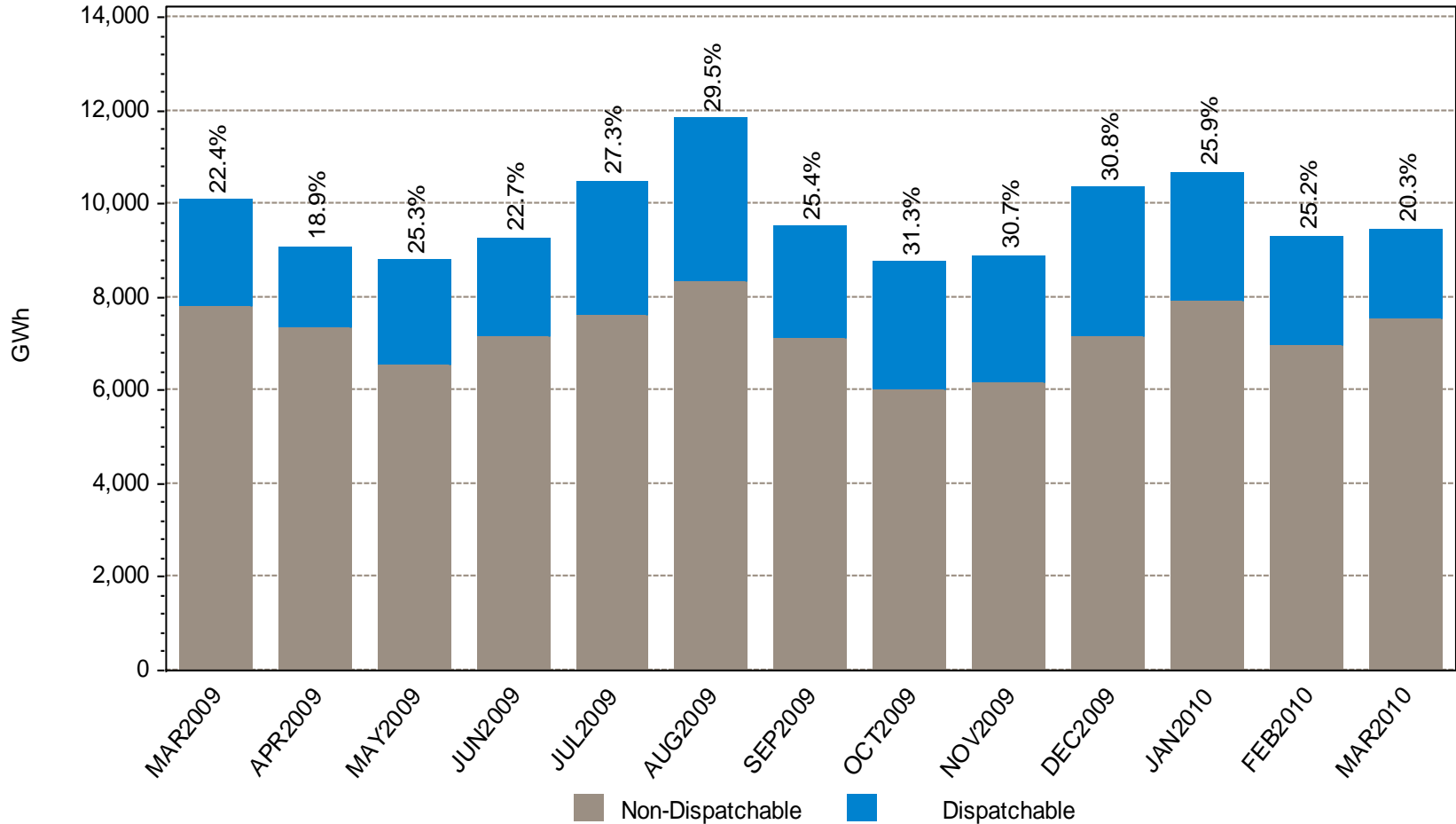
Zonal Level, Last 13 Months



Data excludes nodal offers and bids

# Dispatchable vs. Non-Dispatchable Generation

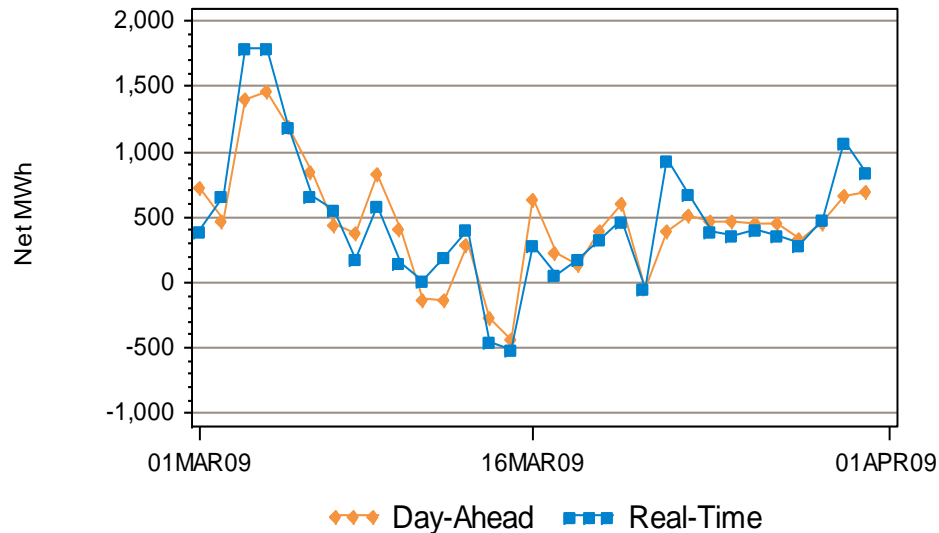
Total Monthly Energy; Dispatchable % Shown



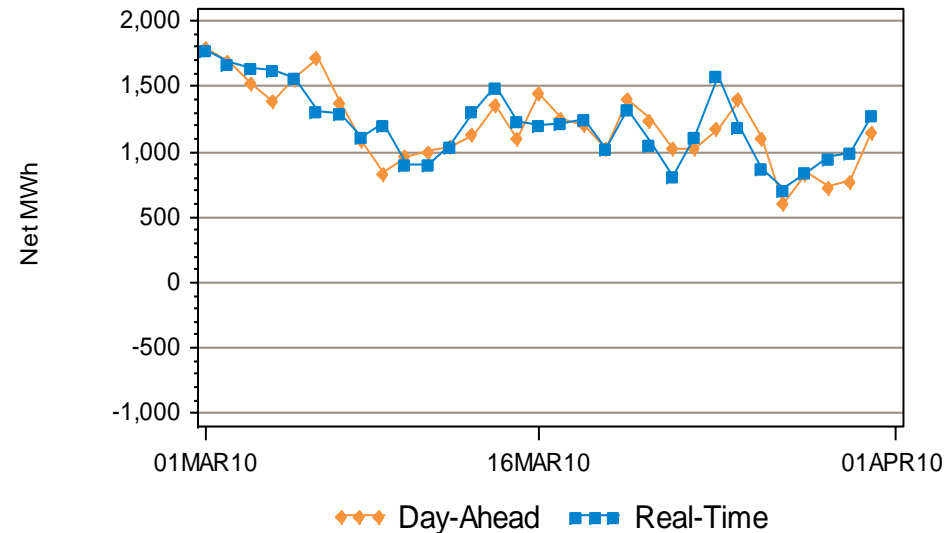
# DA vs. RT Net Interchange

## March 2010 vs. March 2009

Hourly Average by Day, Last Year



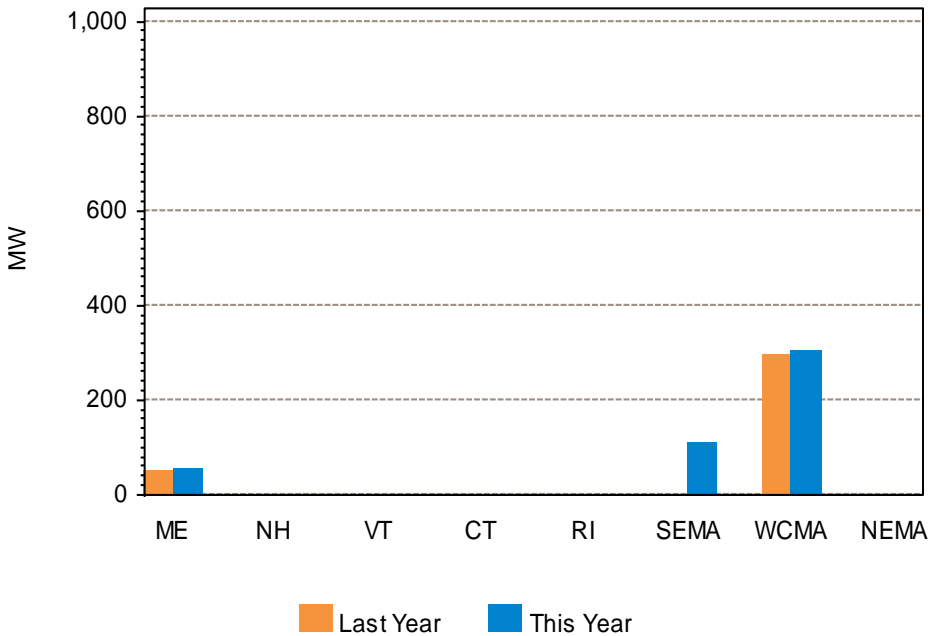
Hourly Average by Day, This Year



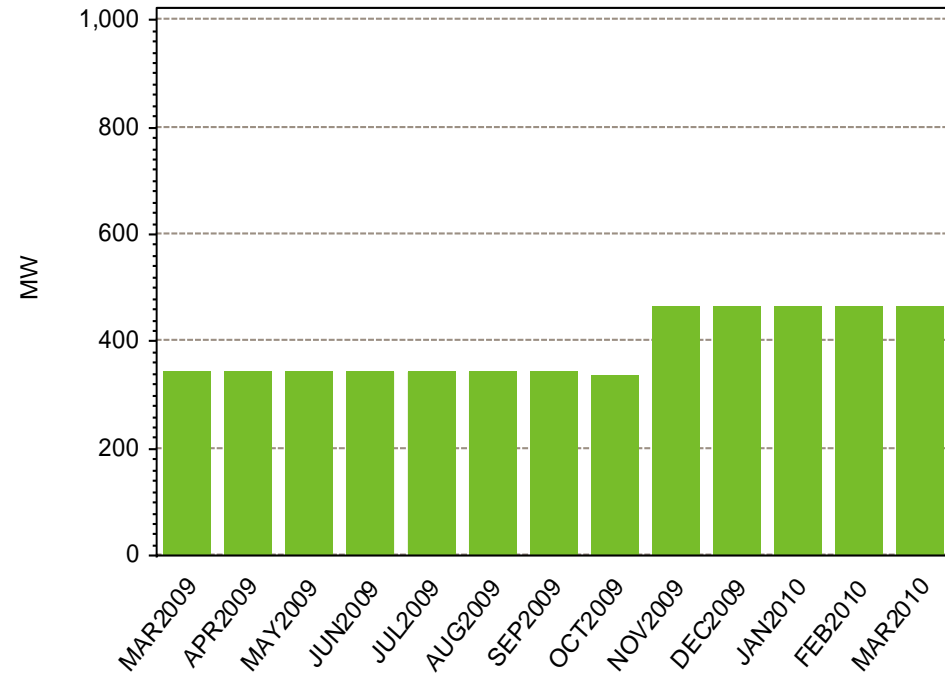
Net Interchange is the sum of daily imports minus the sum of daily exports  
Positive values are net imports

# Delisted Capacity, March 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<sup>(1)</sup></u>	<u>Summer MW*</u>	<u>\$/kw-month<sup>(1)</sup></u>	<u>Effective Date</u> "R" = Requested
<b>Status: Effective with Final Federal Energy Regulatory Commission (FERC) Approval</b>				
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
<b>Status: Terminated or Termination Pending</b>				
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

<sup>(1)</sup>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>

No change from prior month

# Requests for Reliability Determinations

<u>Unit</u>	<u>Summer MW*</u>	<u>Zone Location</u>	<u>Date Received</u>	<u>Date of Determination</u>
<b>Status: Needed for System Reliability</b>				
FPL Energy Yarmouth (aka Wyman) 1 & 2	103	ME	12/11/08	06/23/09
<b>Status: Needed for System Reliability as of date of determination - Generator did not pursue a Reliability Agreement</b>				
Con Edison - West Springfield 10	17	WCMA	08/19/05	02/23/06
<b>Status: Not Needed for System Reliability as of Date of Determination</b>				
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

No change from prior month

# Regional System Plan (RSP)

# Regional System Plan

- Planning Advisory Committee (PAC) meeting scheduled for April 27 to discuss the following
  - Stakeholder Requests for 2010 Economic Studies
  - Operating Reserve Projections
  - Representative Installed Capacity Requirements
  - Representative Local Sourcing Requirements and Maximum Capacity Limits
  - RSP Project Listing Update
  - Long-term Lower SEMA Update on Needs and Proposed Solutions
  - G185 S Reconductoring Project
  - Cost Estimating and Controls WG Update – Auburn Project
  - Cost Estimating and Controls WG Update – Grand Avenue Project

# 2010 Economic Study Requests

- 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 2010 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 held April 30 to discuss the following
  - IPSAC Comments on the draft Northeast Coordinated System Plan 2009 (NCSP09) and Next Steps
  - IREMM Study
  - Interregional Cost Allocation
- Environmental Advisory Group (EAG) teleconference scheduled for April 16

# Eastern Interconnection Planning Collaborative (EIPC)

- EIPC and DOE still working to finalize agreement
- EIPC Roll-up Working Group moving forward with model development
- Keystone held three webinars in March with focus on consideration of a straw proposal with two options on Stakeholder Steering Committee (SSC) make-up. Regional caucus to elect SSC reps with the following options
  - Option A - 20 reps with 6 sectors getting 2 reps each, the states getting 7 reps and 1 Canadian rep
  - Option B - increase to 29 reps with 3 reps in each sector, 10 state reps and 1 Canadian rep
- Face-to-face stakeholder meeting slated for April 22-23 to continue to discuss SSC make-up

# 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 4/5/10

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

Upgrade	Expected In-service	Present Stage
<b>Wakefield Junction/Merrimack Valley</b>		
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 4/5/10

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

<b>Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
Expand the Carver substation	Dec-12	1
Build new 345 kV line from Carver to Sandwich	Dec-12	1
Expand Sandwich to include 345-115 kV autotransformer	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 or Exclusion)	Dec-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 4/5/10

*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 4/5/10

*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*

<b>Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
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 4/5/10

*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*

<b>Sample Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
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 Solution
  - ISO involvement in RI siting for RIRP complete
    - No determination yet
  - Siting application filed with MA and CT for Springfield portion in October 2008
    - Springfield – CT
      - CT Siting Council approved entire project except for the Manchester – Meekville Junction double-circuit separation portion (known as MMP)
      - NU to file supplemental testimony / studies on pros / cons of MMP versus MMP-V (separate the 395 3-terminal line into 2 separate lines)
    - Springfield – MA
      - Initial brief filed 3/26/10

# 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
  - Briefs and reply briefs have been filed

# Operable Capacity Analysis

# 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 March Seasonal Claimed Capability (SCC) Report)	33,610	SAME
Net ICAP Purchases	58	SAME
New Generation	100	SAME
Net Resources***	33,770	SAME
Assumed Outages**	10,100	SAME
Generation at Risk Due to Gas Supply	0	SAME
Peak Load Exposure (adjusted for Other Demand Resources)	19,970	21,572 (+1,602)
Reserve Requirement	1,800	SAME
Operable Capacity Required	21,770	23,372 (+1,602)
Operable Capacity Margin***	1,900	300 (-1,600)

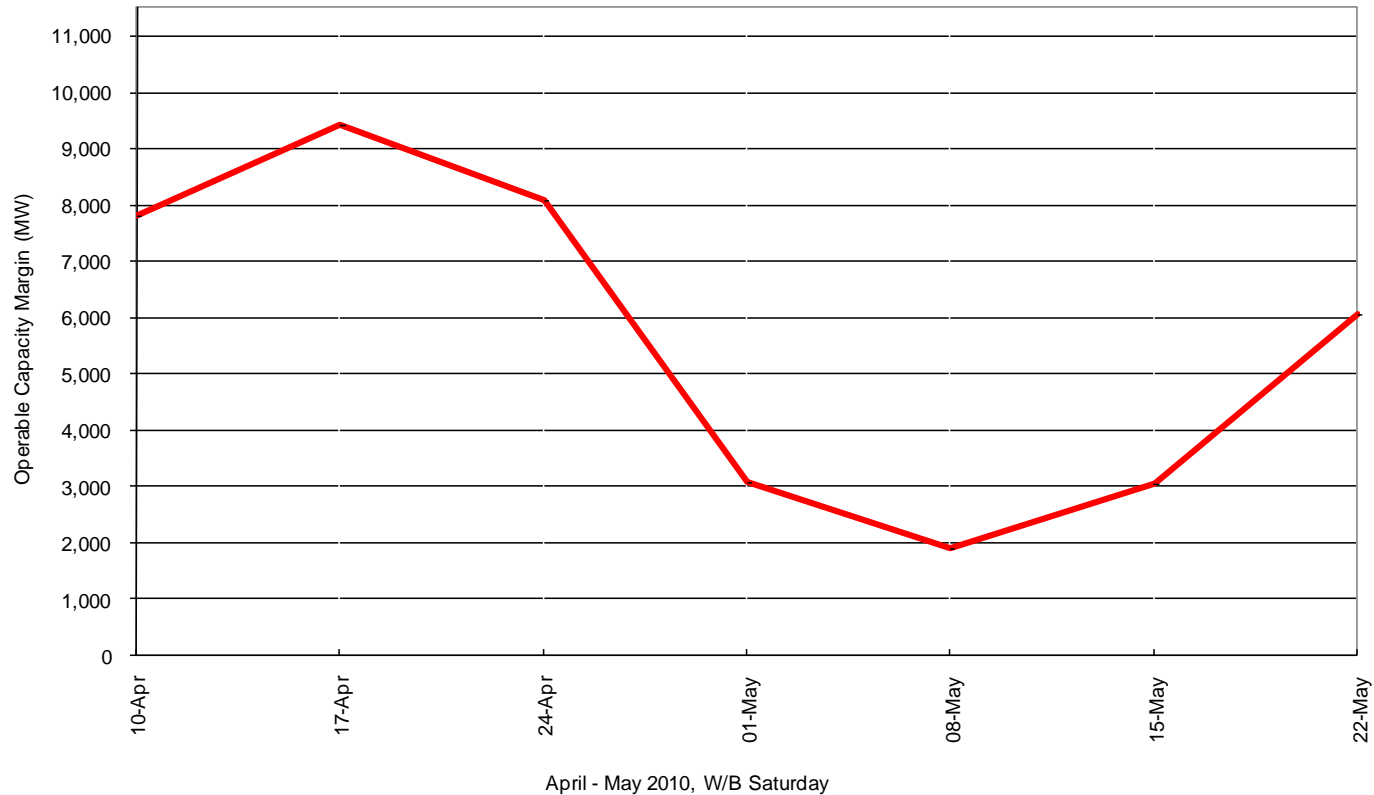
•Based on week with lowest Operable Capacity Margin, week beginning May 8<sup>th</sup>. Mystic 8 & 9 limited to 1,200 MW. Does not include Settlement Only Resources (approx. 250 MW) and Demand Response Resources (2,279 MW).

\*\* Assumed Outages include 3,400 MW of Unplanned Outages, and 6,700 MW of Planned Outages

\*\*\* Rounded to the nearest ten

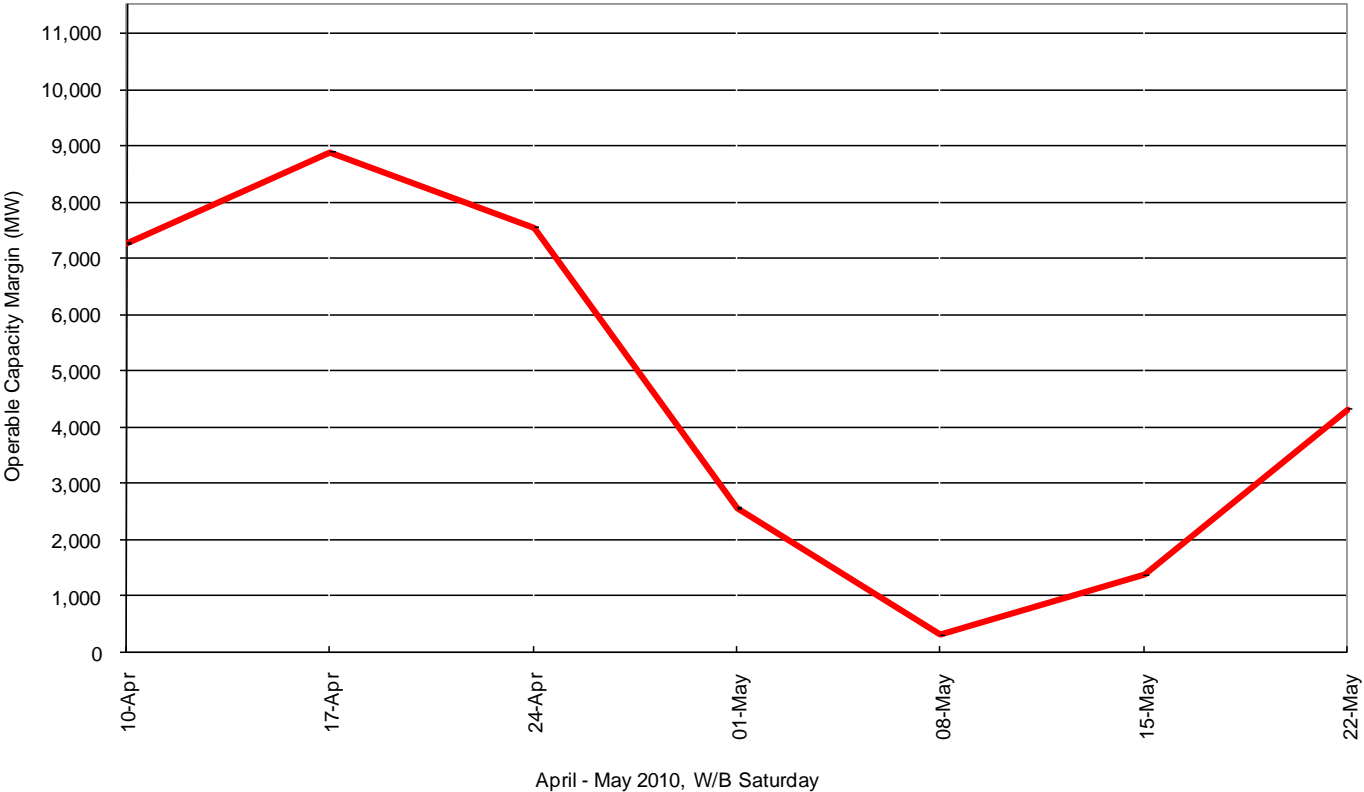
# Spring 2010 Operable Capacity Analysis (MW) 50/50 Forecast (Reference)

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



# 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*	237
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*	1,153
	Voltage Reduction requiring > 10 minutes	82
13	Voltage Reduction requiring < 10 minutes	366
15	Radio and TV Appeal	200
<b>Total</b>		<b>4,462</b>

- Total Demand Response MW, including voluntary price response = 2,279 MW (real time price response = 65 MW)
- Demand Response based on data as of 4/01/2010
- OP-4 Actions based on a 28,048 MW system load

# Summer 2010 Operable Capacity Analysis (MW)

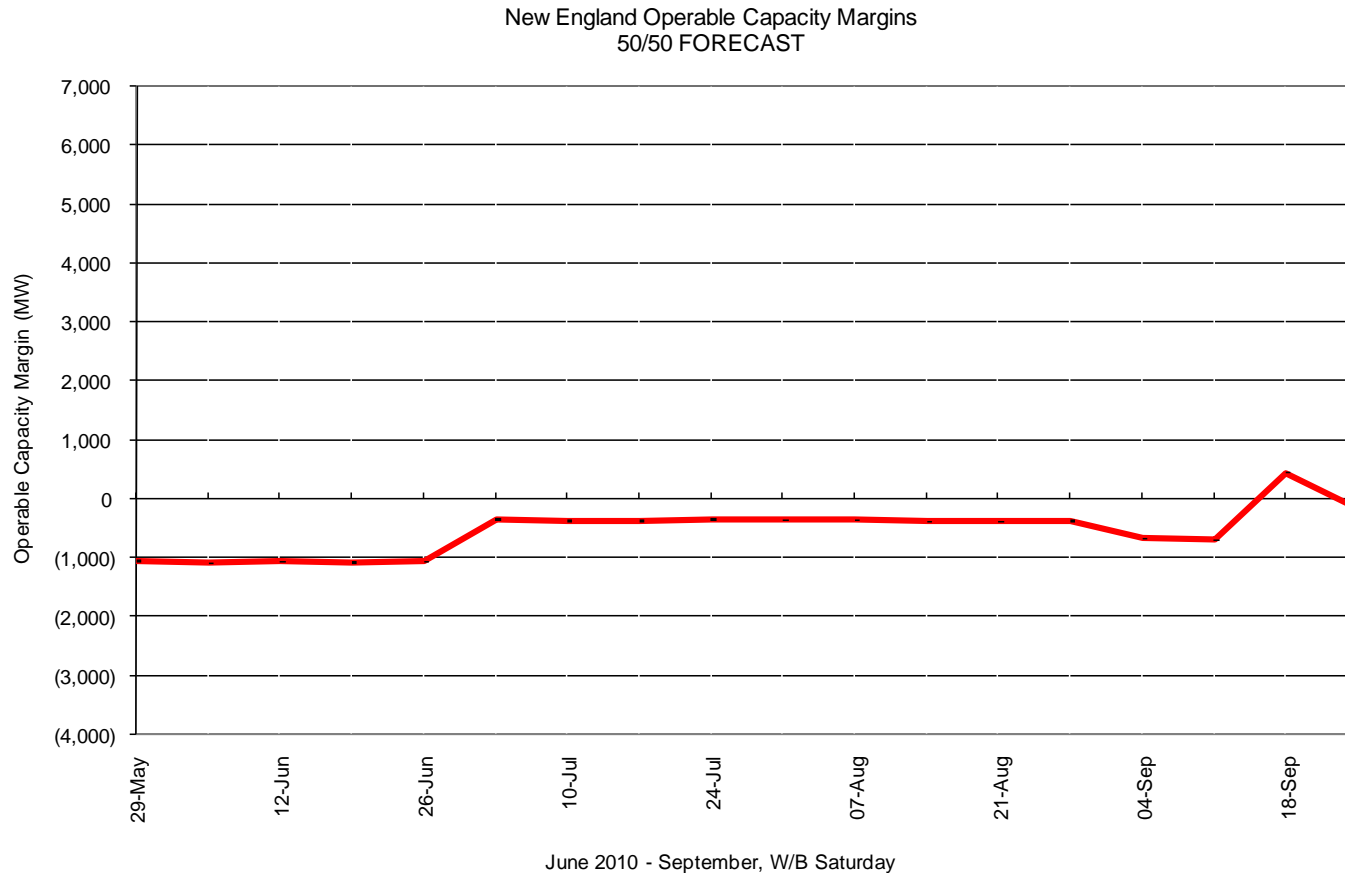
	June-10* 50/50 Forecast (Reference Load )	June-10* 90/10 Forecast (Extreme Load)
Available Capacity (based on resource Capacity Supply Obligation, CSO minus Planned Outages)	29,835	SAME
External Node Available capacity	300	SAME
Non Commercial Supply	0	SAME
Net Capacity	30,135	SAME
Allowance for Unplanned Outages	2,800	SAME
Generation at Risk Due to Gas Supply	0	SAME
Peak Load Exposure (adjusted for Other Demand Resources)	26,618	28,738 (+2,120)
Reserve Requirement	1,800	SAME
Operable Capacity Required	28,418	30,538 (+2,120)
Operable Capacity Margin***	(1,083)	(3,203) (-2,120)

•Based on week with lowest Operable Capacity Margin, week beginning June 5<sup>th</sup>. Mystic 8 & 9 limited to 1,200 MW. Does not include Settlement Only Resources and Demand Response Resources.

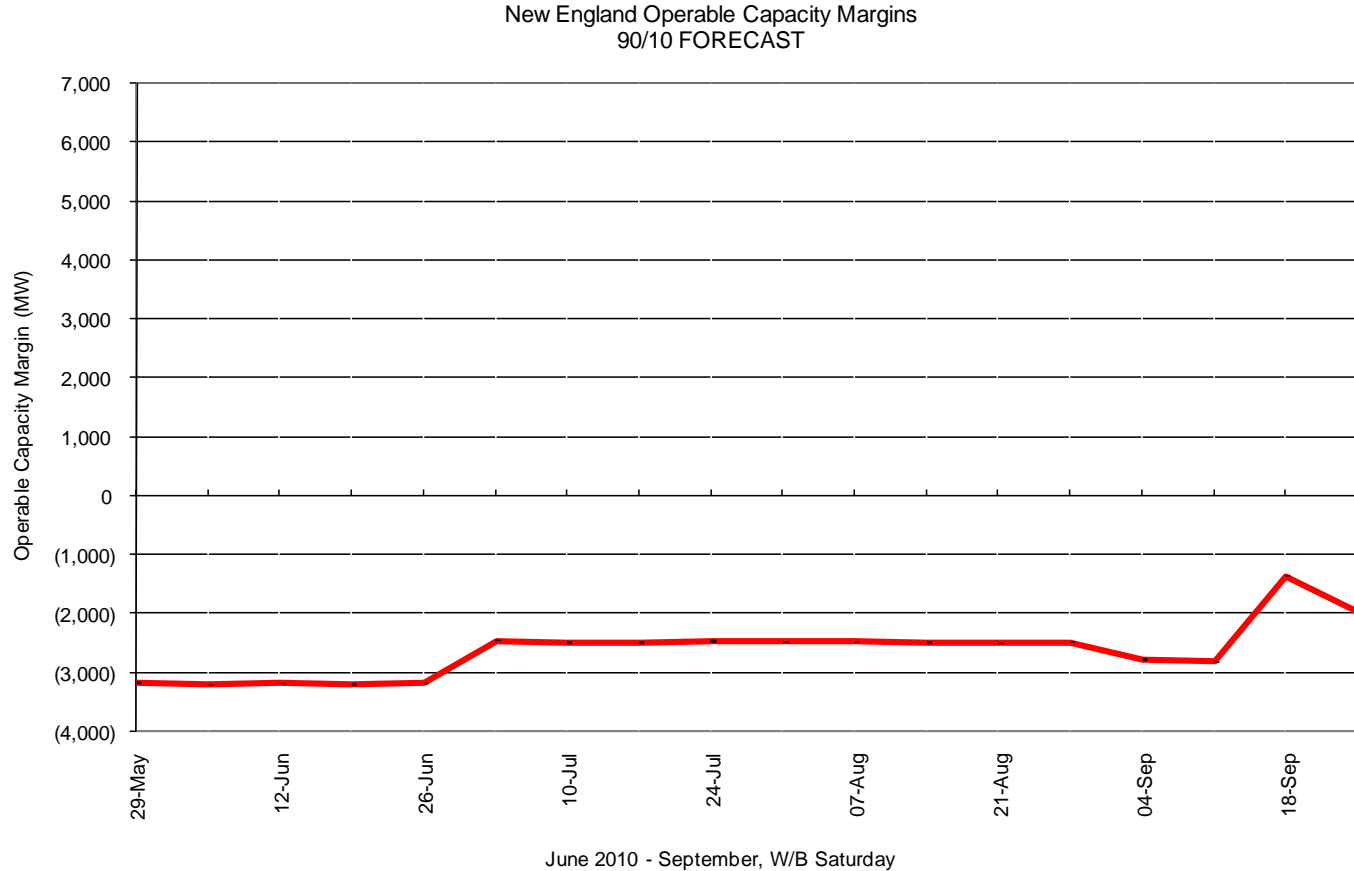
\*\* Assumed Outages include 2,800 MW of Unplanned Outages, and 0 MW of Planned Outages

\*\*\* 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)



# Possible Relief Under OP4 (after 5/31/10) based on OP4 Appendix A

OP 4 Action Number	Action Description	Amount Assumed Obtainable Under OP 4 (MW)
1	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.	40 <sup>1</sup> 600
2	Dispatch real time Demand Resources.	482 <sup>2</sup>
3	Voluntary Load Curtailment of Market Participants' facilities.	40
5	Schedule Emergency Energy Transactions	1,000
6	Voltage Reduction requiring > 10 minutes Dispatch real time Emergency Generation	82 530
8	Voltage Reduction requiring < 10 minutes	366
9	Voluntary Load Curtailment by Large Industrial and Commercial Customers. Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency.	200 5
11	Request State Governors to Reinforce Power Warning Appeals.	100
15	Radio and TV Appeal	200
Total		3,645

1. Assumes 25% of total MW Settlement Only resources available and respond.

2. Does not include non-commercial Demand Response resources and reserve margin gross-up MW. Performance factor applied.

# Appendix

# Spring 2010 Operable Capacity Analysis (MW)

## 50/50 Forecast (Reference)

### ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

April 5 , 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 Capacity (SCC) [Note 1] (MW)	Net Interchange (NYPP, NB, HQ, Highgate) [Note 2] (MW)	New Generation [Note 3] (MW)	De-listed ICAP resources [Note 4] (MW)	Net Capacity [Note 5] (MW)	Peak Load Exposure [Note 6] (MW)	Operating Reserve Requirement [Note 7] (MW)	(Planned Outages) Total Known Maintenance [Note 8] (MW)	Allowance for Unplanned Outages [Note 8] (MW)	Generation at Risk Due to Gas Supply [Note 9] (MW)	Total Capacity (MW)	Operable Capacity Margin (+/-) (MW)	Extent of OP 4 Actions That May be Necessary (OP 4 Actions up to and including) [Note 10]
2010	April	10	33,598	1,789	100	290	35,489	17,479	1,800	5,700	2,700	0	27,089	7,810	
		17	33,598	1,789	100	290	35,489	16,976	1,800	4,600	2,700	0	28,189	9,410	
	May	24	33,598	1,789	100	290	35,489	16,714	1,800	6,200	2,700	0	26,589	8,080	
		1	33,606	58	100	290	33,768	16,687	1,800	8,800	3,400	0	21,568	3,080	
		8	33,606	58	100	290	33,768	19,970	1,800	6,700	3,400	0	23,668	1,900	
		15	33,606	58	100	290	33,768	20,924	1,800	4,600	3,400	0	25,768	3,040	
		22	33,606	58	100	290	33,768	21,811	1,800	700	3,400	0	29,668	6,060	

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 Capacity per the March 1, 2010 SCC report, Energy Management System units, with an adjustment for capacity increases and decreases expected during the analysis period (SCC = Seasonal Claimed Capacity). 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 Capacity 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 Delisted ICAP sold are rounded to the nearest ten (SCC = Seasonal Claimed Capacity).
6. Peak Load Exposure per data included in the 2010 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.

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

## ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

**April 5 , 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															
Year	Month	Day	Installed Seasonal Claimed Capability (SCC) [Note 1] (MW)	Net Interchange (NYPP, NB, HQ, Highgate) [Note 2] (MW)	New Generation [Note 3] (MW)	De-listed ICAP resources [Note 4] (MW)	Net Capacity [Note 5] (MW)	Peak Load Exposure [Note 6] (MW)	Operating Reserve Requirement [Note 7] (MW)	(Planned Outages) Total Known Maintenance	Allowance for Unplanned Outages [Note 8] (MW)	Generation at Risk Due to Gas Supply [Note 9] (MW)	Total Capacity (MW)	Operable Capacity Margin (+/-) (MW)	Extent of OP 4 Actions That May be Necessary (OP 4 Actions up to and including) [Note 10]
	April	10	33,598	1,789	100	290	35,489	18,037	1,800	5,700	2,700	0	27,089	7,250	
		17	33,598	1,789	100	290	35,489	17,518	1,800	4,600	2,700	0	28,189	8,870	
2010		24	33,598	1,789	100	290	35,489	17,248	1,800	6,200	2,700	0	26,589	7,540	
	May	1	33,606	58	100	290	33,768	17,221	1,800	8,800	3,400	0	21,568	2,550	
		8	33,606	58	100	290	33,768	21,572	1,800	6,700	3,400	0	23,668	300	
		15	33,606	58	100	290	33,768	22,600	1,800	4,600	3,400	0	25,768	1,370	
		22	33,606	58	100	290	33,768	23,556	1,800	700	3,400	0	29,668	4,310	

- 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 March 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 Capability 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 Delisted ICAP sold are rounded to the nearest ten (SCC = Seasonal Claimed Capability).
  6. Peak Load Exposure per data included in the 2010 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

April 5, 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	NON CSO AVAIL SUPPLY 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	29,870	300	30,170	0	26,618	1,800	0	0	2,800	(1,048)	482	(566)
06/05/2010	29,835	300	30,135	0	26,618	1,800	0	0	2,800	(1,083)	482	(601)
06/12/2010	29,849	300	30,148	0	26,618	1,800	0	0	2,800	(1,070)	482	(588)
06/19/2010	29,839	300	30,139	0	26,618	1,800	0	0	2,800	(1,079)	482	(597)
06/26/2010	29,854	300	30,154	0	26,618	1,800	0	0	2,800	(1,064)	482	(582)
07/03/2010	29,874	300	30,174	0	26,618	1,800	0	0	2,100	(344)	482	138
07/10/2010	29,844	300	30,143	0	26,618	1,800	0	0	2,100	(375)	482	107
07/17/2010	29,843	300	30,143	0	26,618	1,800	0	0	2,100	(375)	482	107
07/24/2010	29,866	300	30,166	0	26,618	1,800	0	0	2,100	(352)	482	130
07/31/2010	29,862	300	30,162	0	26,618	1,800	0	0	2,100	(356)	482	126
08/07/2010	29,862	300	30,161	0	26,618	1,800	0	0	2,100	(357)	482	125
08/14/2010	29,840	300	30,140	0	26,618	1,800	0	0	2,100	(378)	482	104
08/21/2010	29,836	300	30,136	0	26,618	1,800	0	0	2,100	(382)	482	100
08/28/2010	29,846	300	30,146	0	26,618	1,800	0	0	2,100	(372)	482	110
09/04/2010	29,554	300	29,854	0	26,618	1,800	0	0	2,100	(664)	482	(182)
09/11/2010	29,525	300	29,824	0	26,618	1,800	0	0	2,100	(694)	482	(212)
09/18/2010	26,763	300	27,062	0	22,722	1,800	0	0	2,100	440	482	922
09/25/2010	26,774	300	27,073	0	22,632	1,800	0	0	2,800	(159)	482	323

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

April 5, 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	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL OPCAP MW	NET OPCAP SUPPLY MW	NON COMMERCIAL CAPACITY MW	LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NON CSO AVAIL SUPPLY 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	29,870	300	30,170	0	28,738	1,800	0	0	2,800	(3,168)	482	(2,686)
06/05/2010	29,835	300	30,135	0	28,738	1,800	0	0	2,800	(3,203)	482	(2,721)
06/12/2010	29,849	300	30,148	0	28,738	1,800	0	0	2,800	(3,190)	482	(2,708)
06/19/2010	29,839	300	30,139	0	28,738	1,800	0	0	2,800	(3,199)	482	(2,717)
06/26/2010	29,854	300	30,154	0	28,738	1,800	0	0	2,800	(3,184)	482	(2,702)
07/03/2010	29,874	300	30,174	0	28,738	1,800	0	0	2,100	(2,464)	482	(1,982)
07/10/2010	29,844	300	30,143	0	28,738	1,800	0	0	2,100	(2,495)	482	(2,013)
07/17/2010	29,843	300	30,143	0	28,738	1,800	0	0	2,100	(2,495)	482	(2,013)
07/24/2010	29,866	300	30,166	0	28,738	1,800	0	0	2,100	(2,472)	482	(1,990)
07/31/2010	29,862	300	30,162	0	28,738	1,800	0	0	2,100	(2,476)	482	(1,994)
08/07/2010	29,862	300	30,161	0	28,738	1,800	0	0	2,100	(2,477)	482	(1,995)
08/14/2010	29,840	300	30,140	0	28,738	1,800	0	0	2,100	(2,498)	482	(2,016)
08/21/2010	29,836	300	30,136	0	28,738	1,800	0	0	2,100	(2,502)	482	(2,020)
08/28/2010	29,846	300	30,146	0	28,738	1,800	0	0	2,100	(2,492)	482	(2,010)
09/04/2010	29,554	300	29,854	0	28,738	1,800	0	0	2,100	(2,784)	482	(2,302)
09/11/2010	29,525	300	29,824	0	28,738	1,800	0	0	2,100	(2,814)	482	(2,332)
09/18/2010	26,763	300	27,062	0	24,538	1,800	0	0	2,100	(1,376)	482	(894)
09/25/2010	26,774	300	27,073	0	24,441	1,800	0	0	2,800	(1,968)	482	(1,486)

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.