NEPOOL Participants Committee Report June 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**
  - May natural gas prices over the period were 3.2% higher while oil prices were 7.8% lower than April 2010 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were up 35.5% from April 2010 averages

Data through May 26, 2010 unless otherwise noted.

Underlying natural gas data furnished by:

ICE Global markets in clear view

Highlights (cont'd.)

- **Daily Net Commitment Period Compensation (NCPC)***
  - May payments total $7.3M over the period, up $5.3M from April
  - First Contingency payments total $6.5M, up $5.4M from April
    - $6.4M paid to internal resources, up $5.9M from April
      - $701K charged to DALO, $5.7M to RT Deviations
    - $42K paid to resources at external locations, down $483K from April
      - $23K charged to DALO at external locations, $19K to RT Deviation
  - Second Contingency payments total $783K, down $104K from the April total of $886K
    - $783K in CT, up $53K from April due to generation and transmission outages
  - Voltage payments total $28K, up $28K from April
  - Distribution payments total $0K, down $25K from April
  - NCPC payments as percent of Energy Market value were 1.9%

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

Highlights

- The Planning Advisory Committee (PAC) meeting held on May 25 was “Environmental Day” covering a wide range of environmental policies and renewable resources
- The PAC meeting planned for June 16 will discuss Economic Studies, the RSP Project List, and Transmission Studies
- The Northeast Coordinated System Plan 2009 (NCSP09) has been finalized and posted on the ISO website
- State siting of major transmission projects continues to move forward. The Maine PUC approved a settlement agreement with regards to the Maine Power Reliability Program (MPRP), and a final order is anticipated in the near future.
- U.S. Department of Energy (DOE) has dropped New England from its list of “congestion areas of concern”

EIPC Update

- EIPC and DOE still working to finalize contract
- Eastern Interconnection model development effort underway
- Stakeholders agreed to Stakeholder Steering Committee (SSC) structure
  - 29 seat committee (3 seats for each of the 6 Sectors, 10 for States, and 1 for Eastern Canadian provinces)
  - 27 Member Sector Caucus for each Sector with 3 regional reps from each of the 9 regions to elect their 3 members to the SSC
  - Online voting process to be utilized with alternative process available for NGO and End User Sectors
  - First SSC meeting expected in mid-July

Highlights

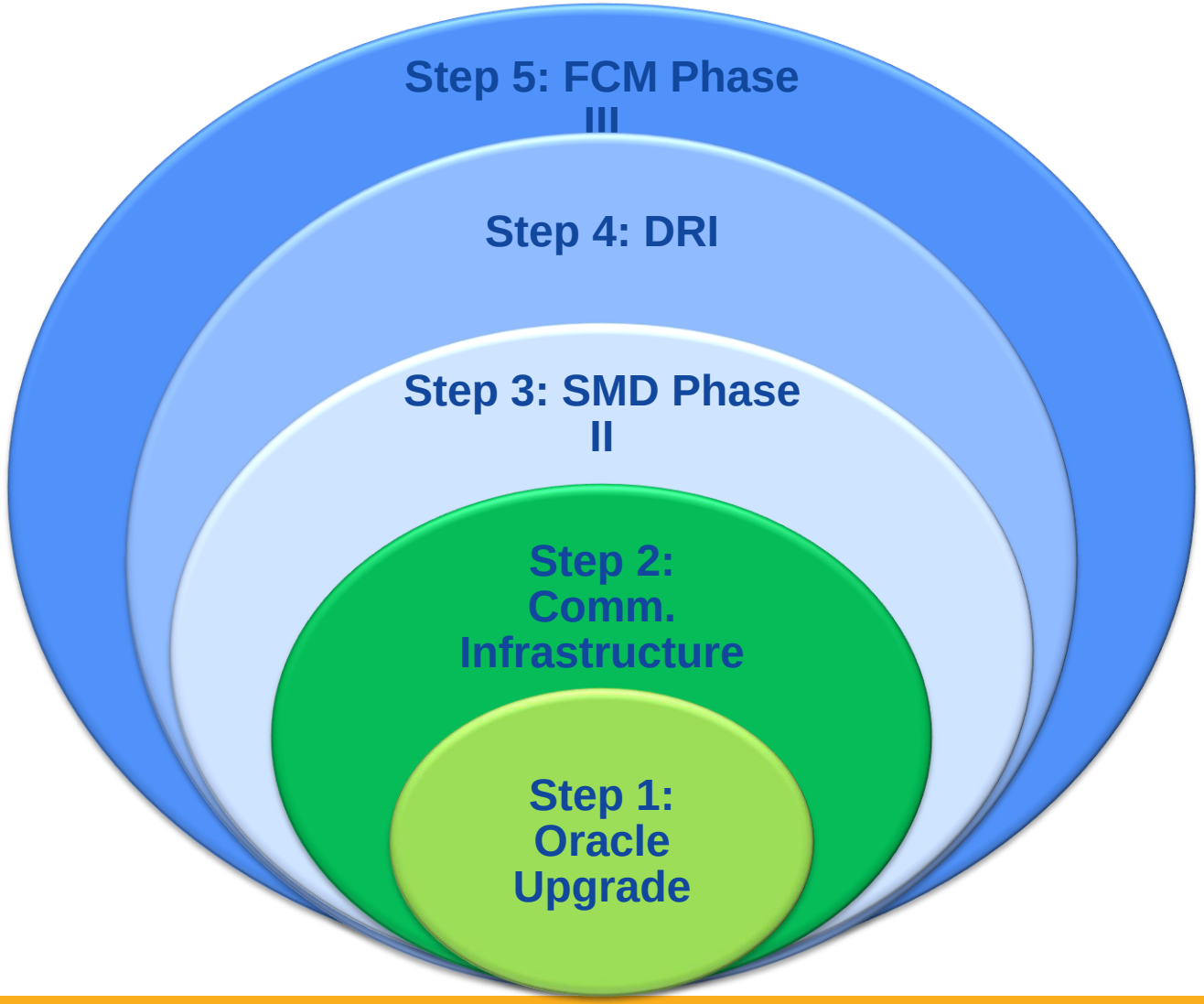
- The lowest Summer Operable Capacity Margin is being calculated for the week beginning June 5th.

Project Implementation

Project Implementation

- As previously noted, there was a higher risk profile to the 2010 project portfolio
- **June 1, 2010 was a major milestone and marked the completion of the following projects**
  - Upgrade of the Oracle database
  - Installation of a state-of-the-art Communications Infrastructure to communicate with generation and demand assets
  - SMD Software Upgrade Phase II
  - Forward Capacity Market (FCM) Phase III
  - Demand Resource Integration (DRI)
- These projects had interdependencies and needed to be implement in a staged manner

Project Implementation Sequence



Shortage Event Implementation and Analysis of System Events in May

Introduction

- Over the last month, ISO staff has reviewed the details of the power system events in May, has analyzed how dispatch in those conditions might differ after June 1 under the new Operating Procedure 4, and has reviewed the Shortage Event triggering rules

Summary of Power System Conditions in May

- The weather forecast error due to unseasonably hot weather on several days impacted the load forecast
  - May 3rd (17,501 MW) recorded as 2nd highest peak ever for that week
  - May 26th (22,837 MW) recorded as the highest peak ever for May
- Significant amount of generation and transmission maintenance
  - Approximately 12,000 MW of generation maintenance outages
- A lot of normally dispatched generation west of the east-west interface was out of service
  - Compounded by transmission work on the east-west interface
- Limited flexibility in real-time to commit units because of their lead time to start-up
- Transmission system improvements have minimized the need for supplemental commitments resulting in limited surplus generation committed day-ahead

May Power System Events

- There were several events in May with respect to M/LCC2, OP-4 and Reserve Constraint Penalty Factor (RCPF) activations for thirty minute operating reserves
  - May 2, 2010 M/LCC2, RCPF activation and OP-4
  - May 3, 2010 M/LCC2, RCPF activation
  - May 8, 2010 M/LCC2, RCPF activation
  - May 26, 2010 M/LCC2, RCPF activation and OP-4

Implementation of Shortage Events

- Based upon the analysis of events in May, effective June 1, the ISO has tied the declaration of Shortage Events to the Reserve Constraint Penalty Factor activation for Total Ten Minute operating reserves (of 30 or more contiguous minutes)

- This implementation is consistent with the current Market Rules

Implementation of Shortage Events (Continued)

- This implementation is based on the following:
  - NPCC criteria allows each Control Area four hours to recover its thirty-minute reserve
  - The current Market Rules specify a RCPF value of $100 for total 30 minute reserves and $850 for total 10 minute reserves and these values are indicative of the importance of those reserve products
  - Due to the transmission improvements, we have little surplus commitment and therefore we should expect to utilize M/LCC 2 and OP 4 procedures more often. In particular, even small deviations in load forecast, tie schedules and generation/transmission outages may cause us to deplete thirty minute reserves for short periods of time, more frequently than in the past

High Level Assessment of the May System Events post-FCM Implementation

- Using the revised OP-4 version, Actions 1 & 2 would have been implemented system-wide to maintain thirty minute operating reserve during the May events
  - Real-time exports above the day-ahead schedule would have been curtailed prior to declaration of OP-4
  - Implementation of Action 2 allows for the dispatch of Real Time Demand Resources (RTDR) in the amount and location required
  - It is likely that 275 – 375 MW of RTDR would have been required

- Based upon the implementation previously described, the system events in May would not have resulted in a declaration of Shortage Events

Next Steps

- The ISO will discuss any further questions at the next NEPOOL Markets Committee meeting

System Operations

System Operations

Weather Patterns:	Boston	Temperature – Above Average Precipitation – Below Average	Hartford	Temperature – Above Average Precipitation – Below Average

Peak Load:	22,837MW	**May 26, 2010**	17:00

Minimum Generation Emergencies : None

M/LCC2:

5/2,5/3,5/8,5/15,5/16,5/24,5/26,5/29: All due to Capacity Deficiencies

OP-4 :

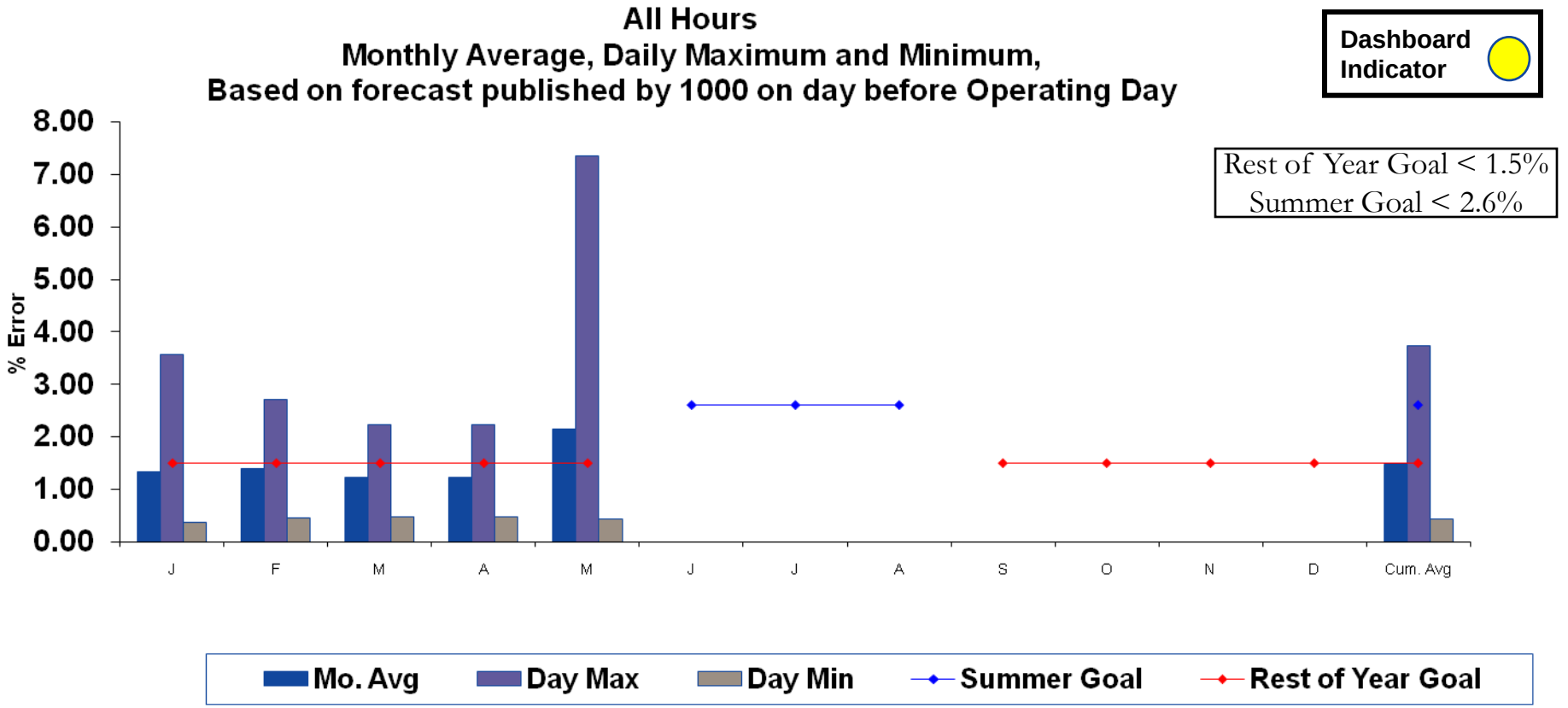
May 2: Capacity Deficiency: Loads ran over forecast

May 26: Capacity Deficiency: Loads ran over forecast and loss of 380Mw generator

NPCC Shared Activation of Reserve Events:

May 10	ISO-NE	700MW
May 14	PJM	1195MW
May 22	ISO-NE	869MW
May 27	ISO-NE	1100MW
May 29	ISO-NE	889MW
May 30	ISO-NE	650MW
May 30	ISO-NE	600MW

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	1.31	1.23	2.15								1.49	Mo Avg
Day Max	3.57	2.72	2.62	2.24	7.35								3.73	Day Max
Day Min	0.37	0.45	0.43	0.48	0.44								0.43	Day Min
Summer Goal						2.60	2.60	2.60						
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50		
Current YTD ROY Avg.													1.49	

Contact: Steve Weaver

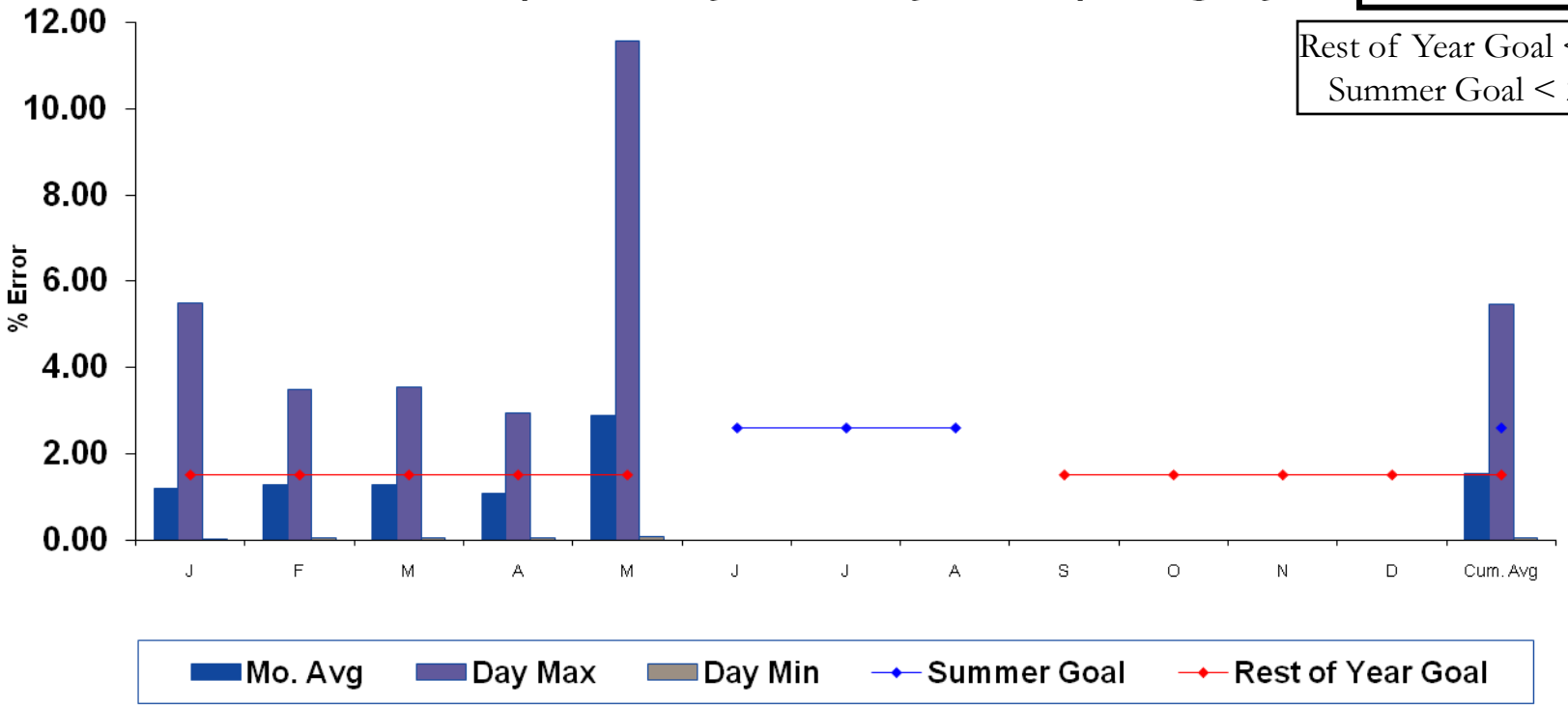
Summer Goal = 2.6% Rest of Year(ROY) Goal = 1.5%
Summer consists of June, July and August-

2010 System Operations - Load Forecast Accuracy cont.

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

Dashboard Indicator

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



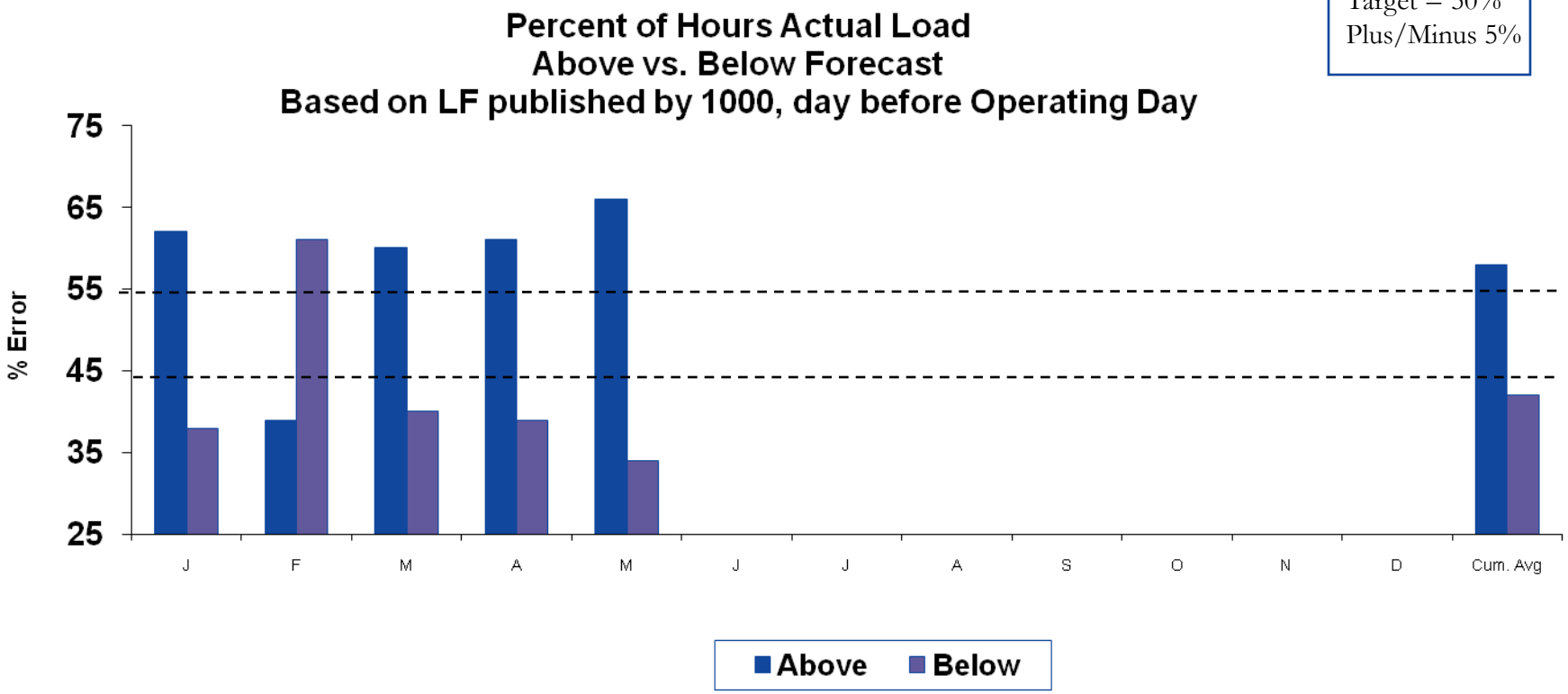
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.20	1.28	1.28	1.10	2.88								1.56
Day Max	5.49	3.49	3.55	2.95	11.56								5.46
Day Min	0.03	0.07	0.05	0.07	0.08								0.06
Summer Goal						2..6	2.6	2.6					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Current YTD ROY													**1.56**

Contact: Steve Weaver

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

2010 System Operations - Load Forecast Accuracy

Target = 50%
Plus/Minus 5%

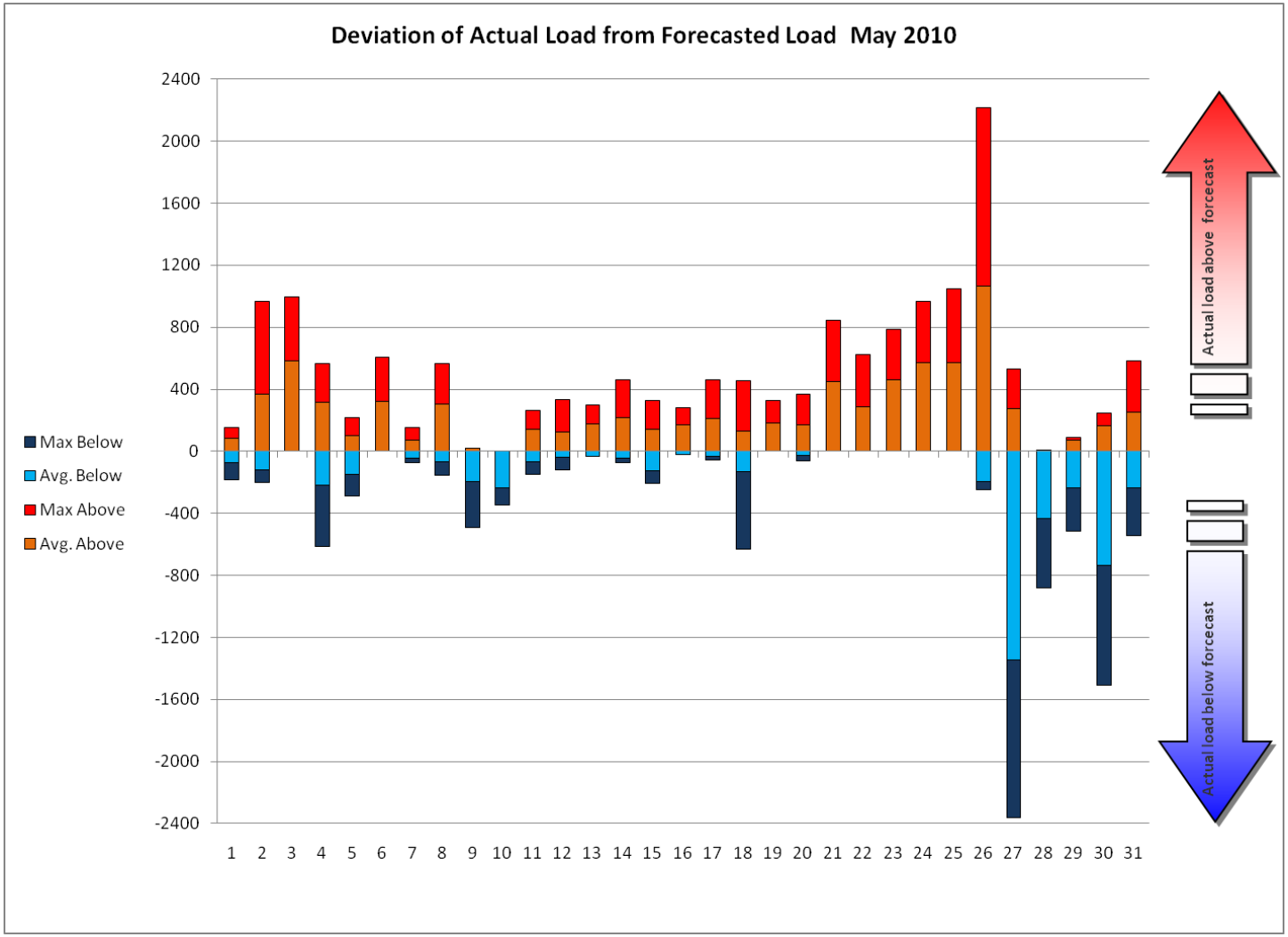


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	62.0	39.0	60.0	61.0	66.0								58.0
Below %	38.0	61.0	40.0	39.0	34.0								42.0
Avg Above	178.0	106.0	144.0	147.0	258.0								168.0
Avg Below	-112.0	-181.0	-118.0	-103.0	-155.0								-133.0
Avg All	74.0	-69.0	38.0	45.0	107.0								41.0

Percent of hours during the month that the actual load was above versus below the forecast

Sponsor: Michael Taniwha
Contact: **Steve Weaver**

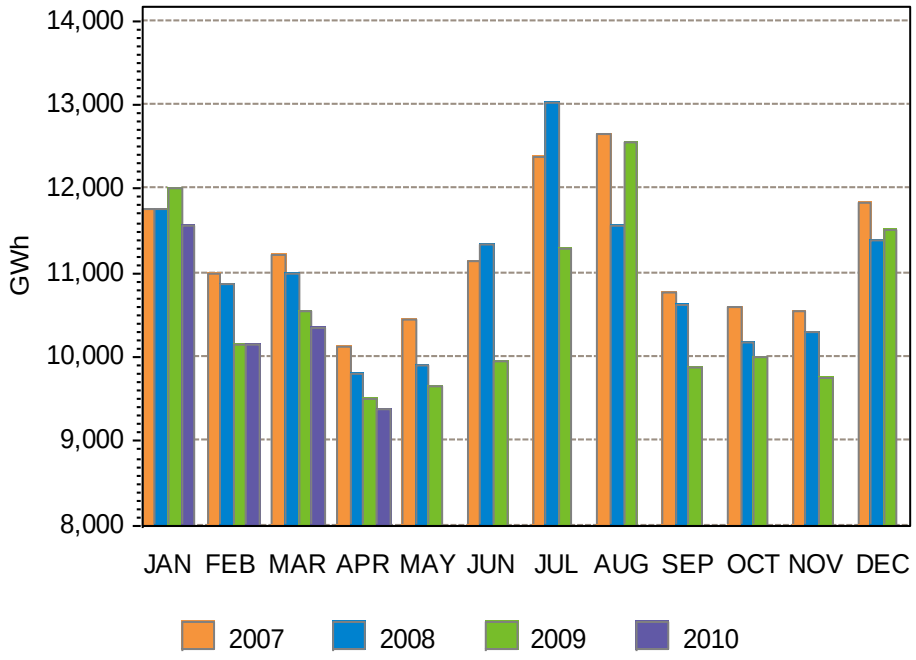
2010 System Operations - Load Forecast Accuracy



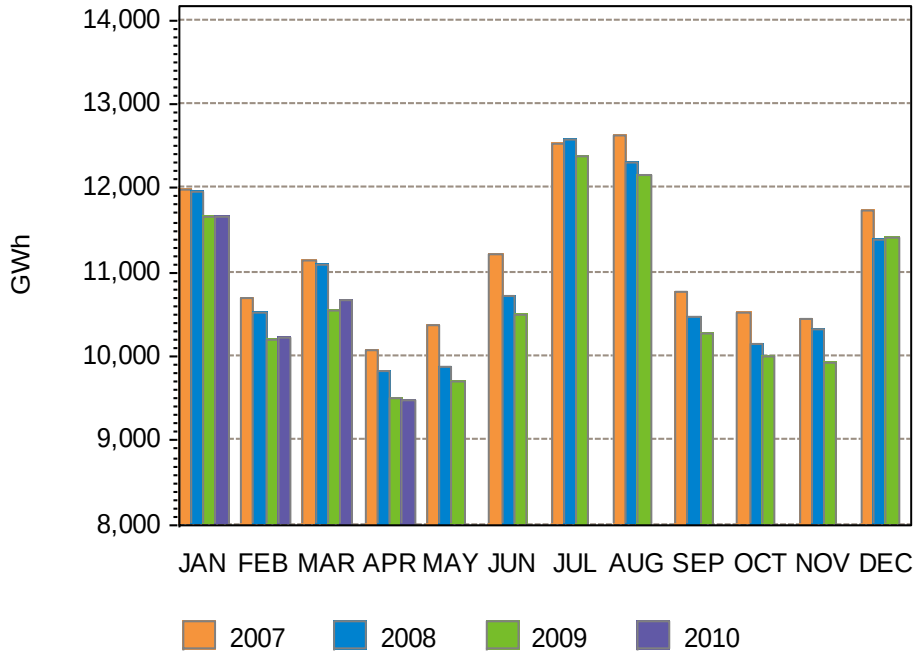
Sponsor	Mike Taniwha
Contact	Steve Weaver

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

Net Energy for Load (NEL)



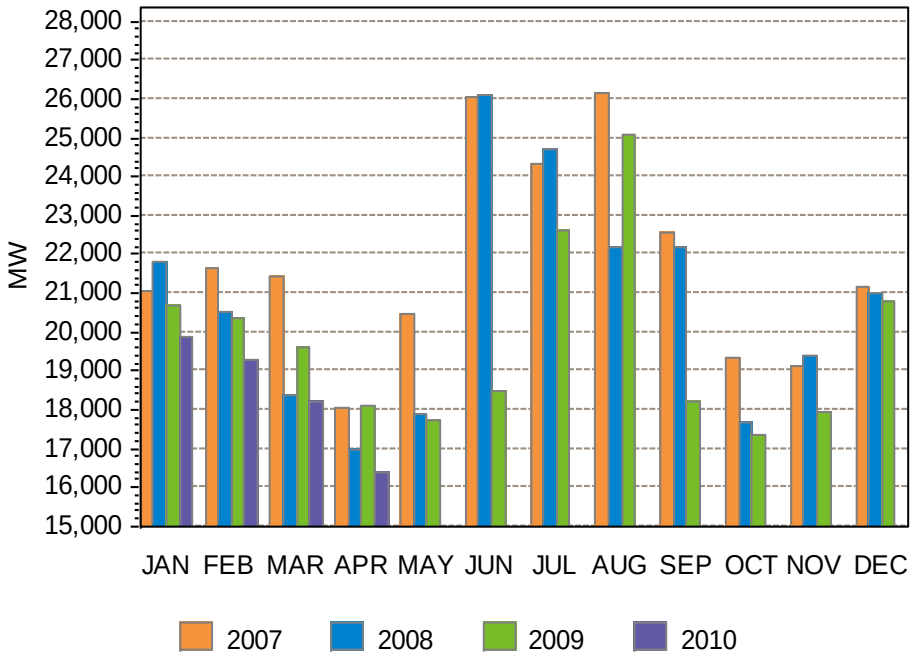
Weather Normalized NEL



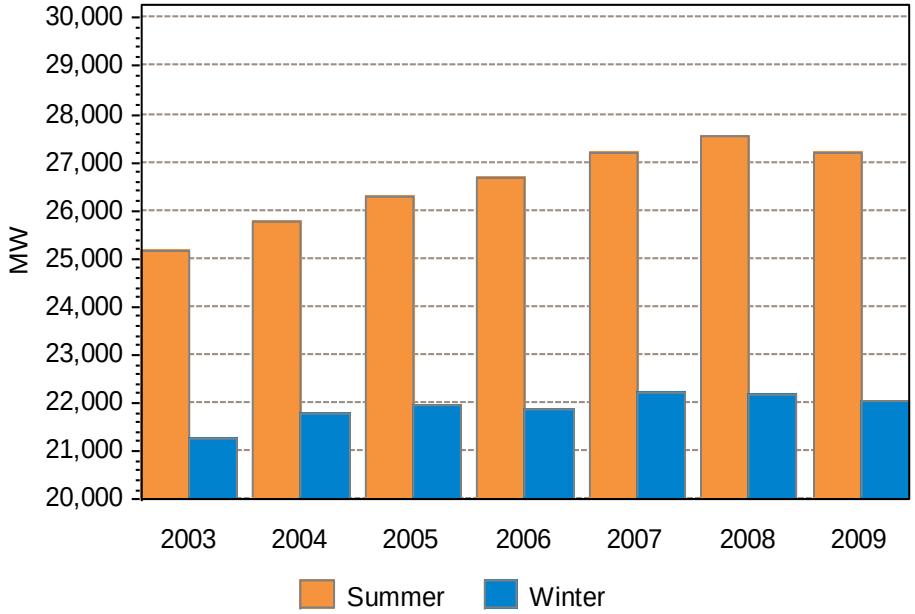
NEPOOL NEL is the total net energy required to serve load for the month, in GWh. NEL is calculated as: Generation – pumping load + net interchange. Reported on a one month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History

System Peak Load



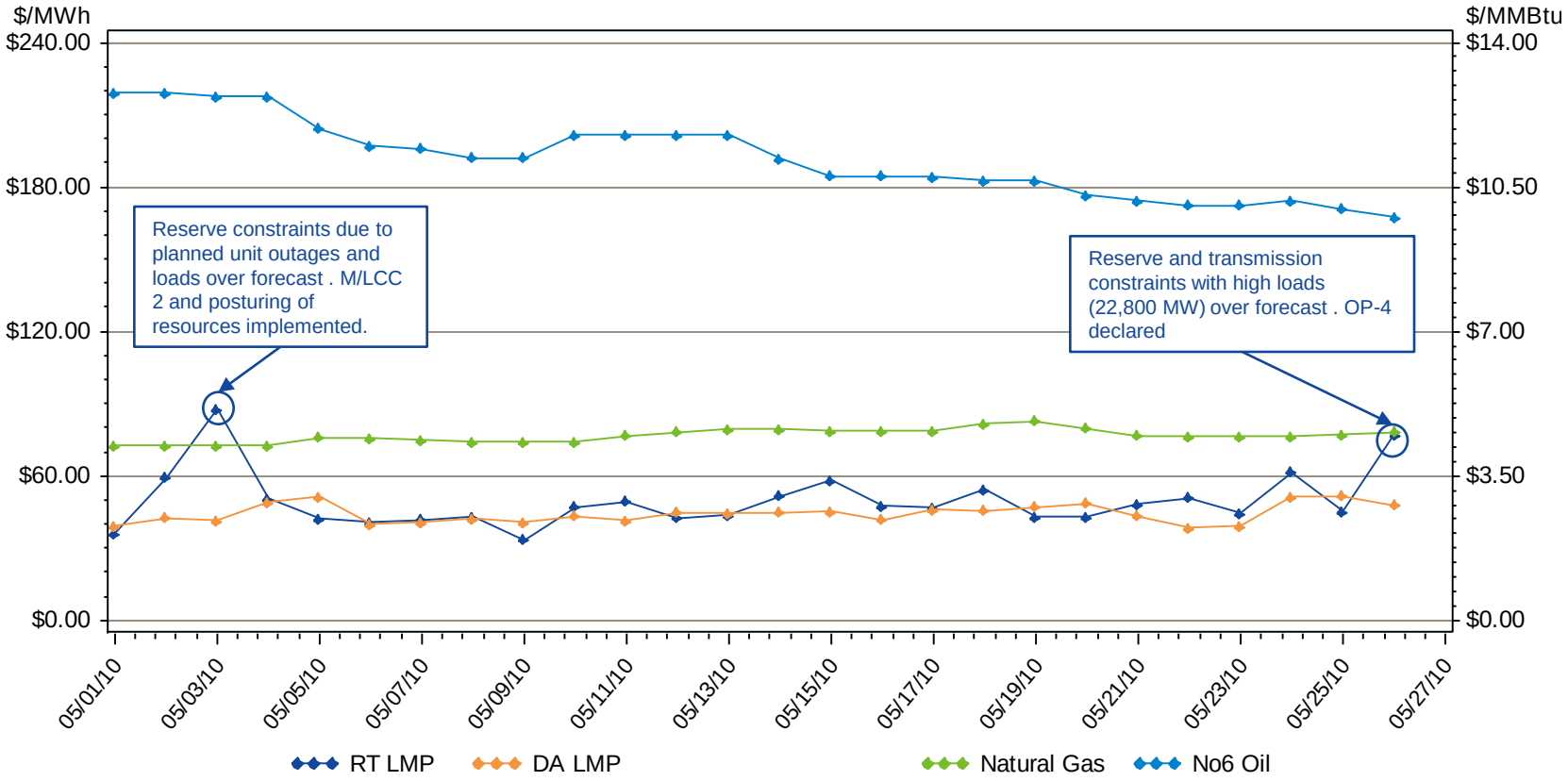
Weather Normalized Seasonal Peaks



Winter beginning in year displayed

Market Operations

DA and RT ISO-NE Hub Prices and Input Fuel Prices: May 1-26, 2010

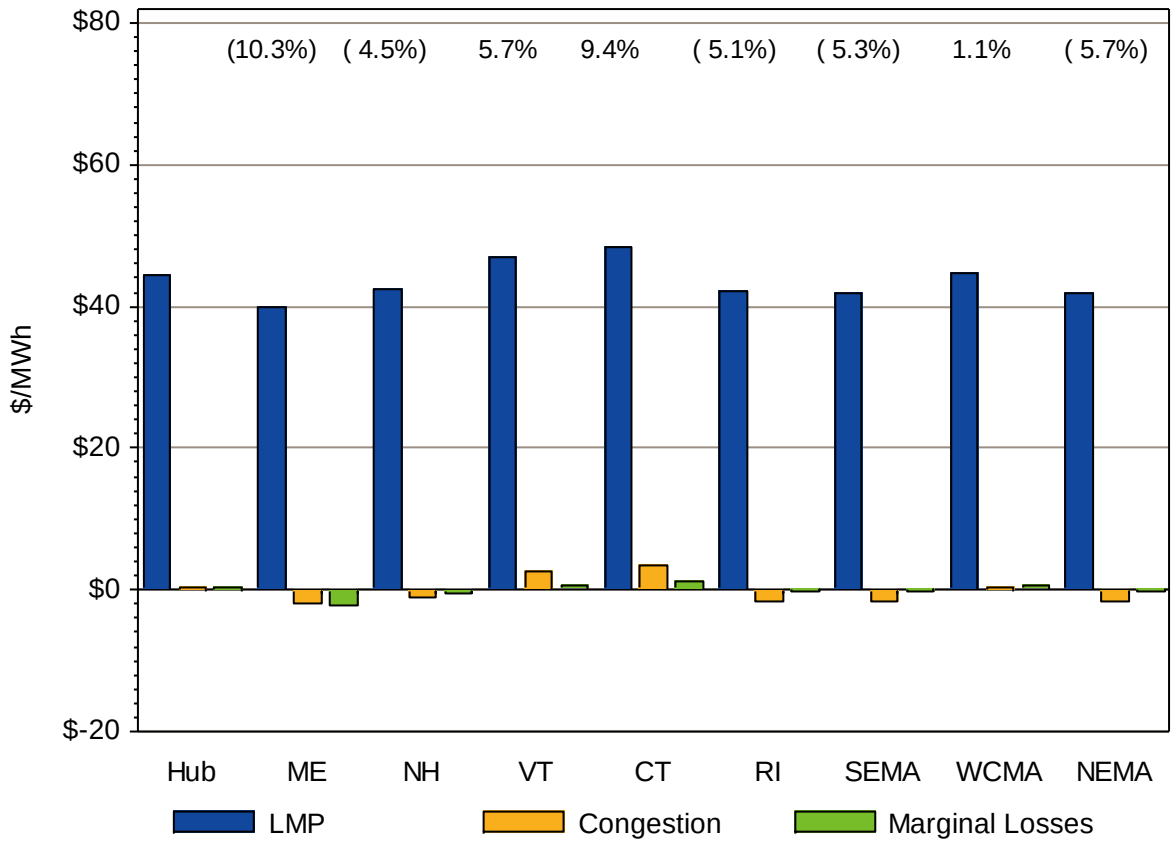


Underlying natural gas data furnished by:

ICE Global markets in clear view

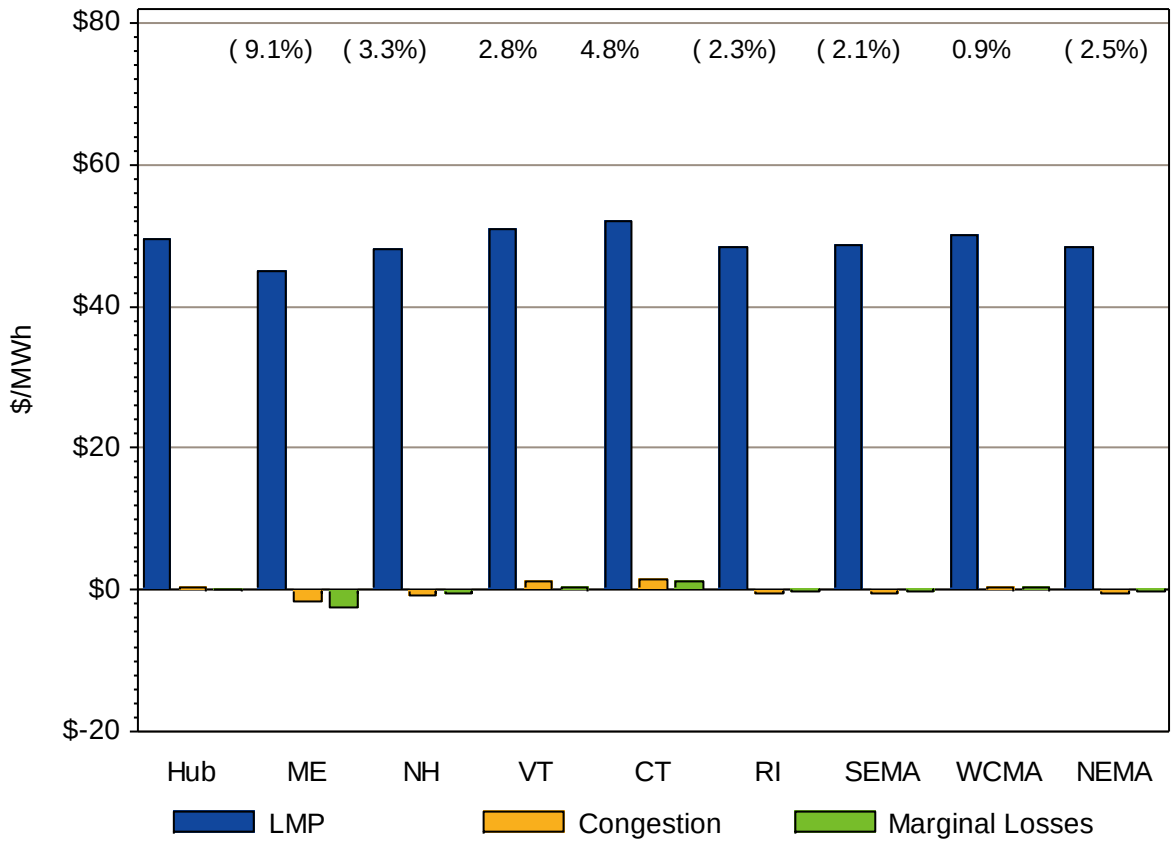
Average price difference over this period (DA-RT): $-5.25
Average price difference over this period ABS(DA-RT): $8.28
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 17%
Gas price is average of Massachusetts delivery points; No6 Oil is New York Spot Price from DOEs Energy Information Administration

DA LMPs Average by Zone & Hub – May 2010



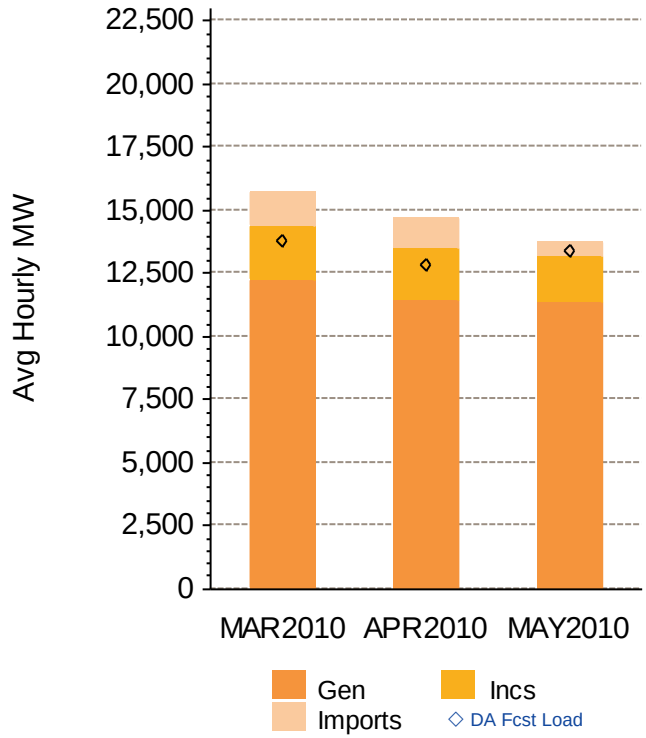
ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut
RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

RT LMPs Average by Zone & Hub – May 2010



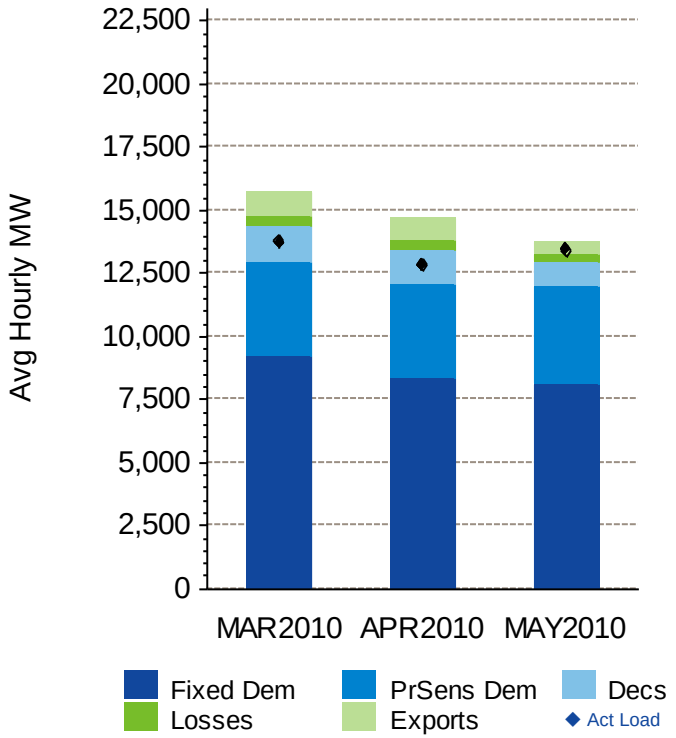
Components of Cleared DA Supply and Demand – Last Three Months

Supply



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

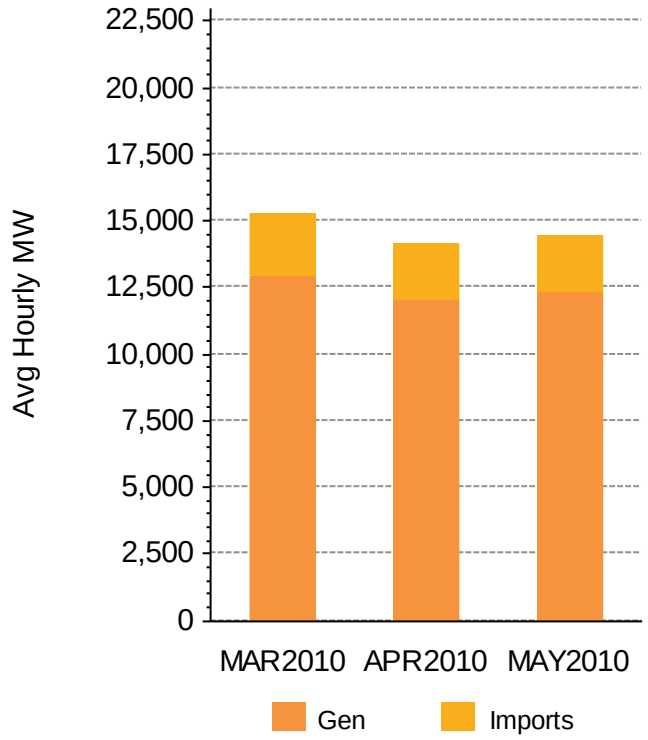
Demand



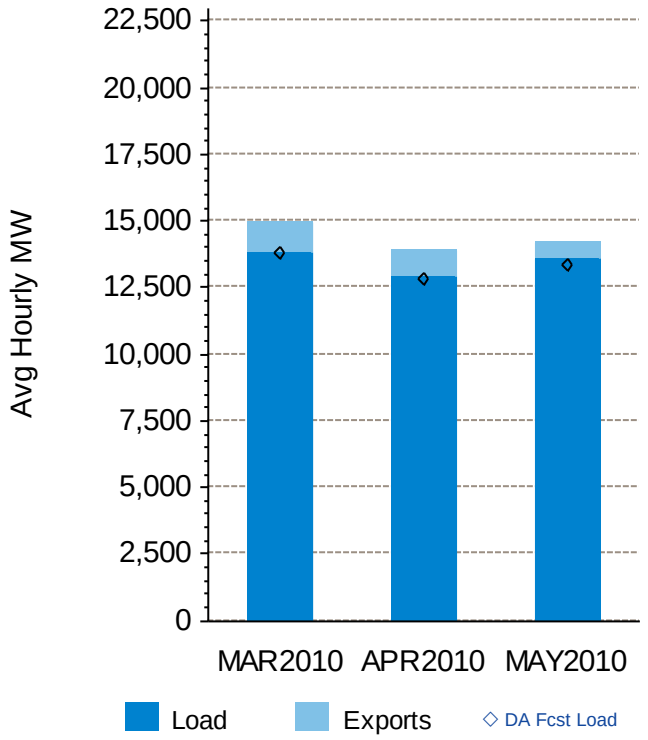
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months

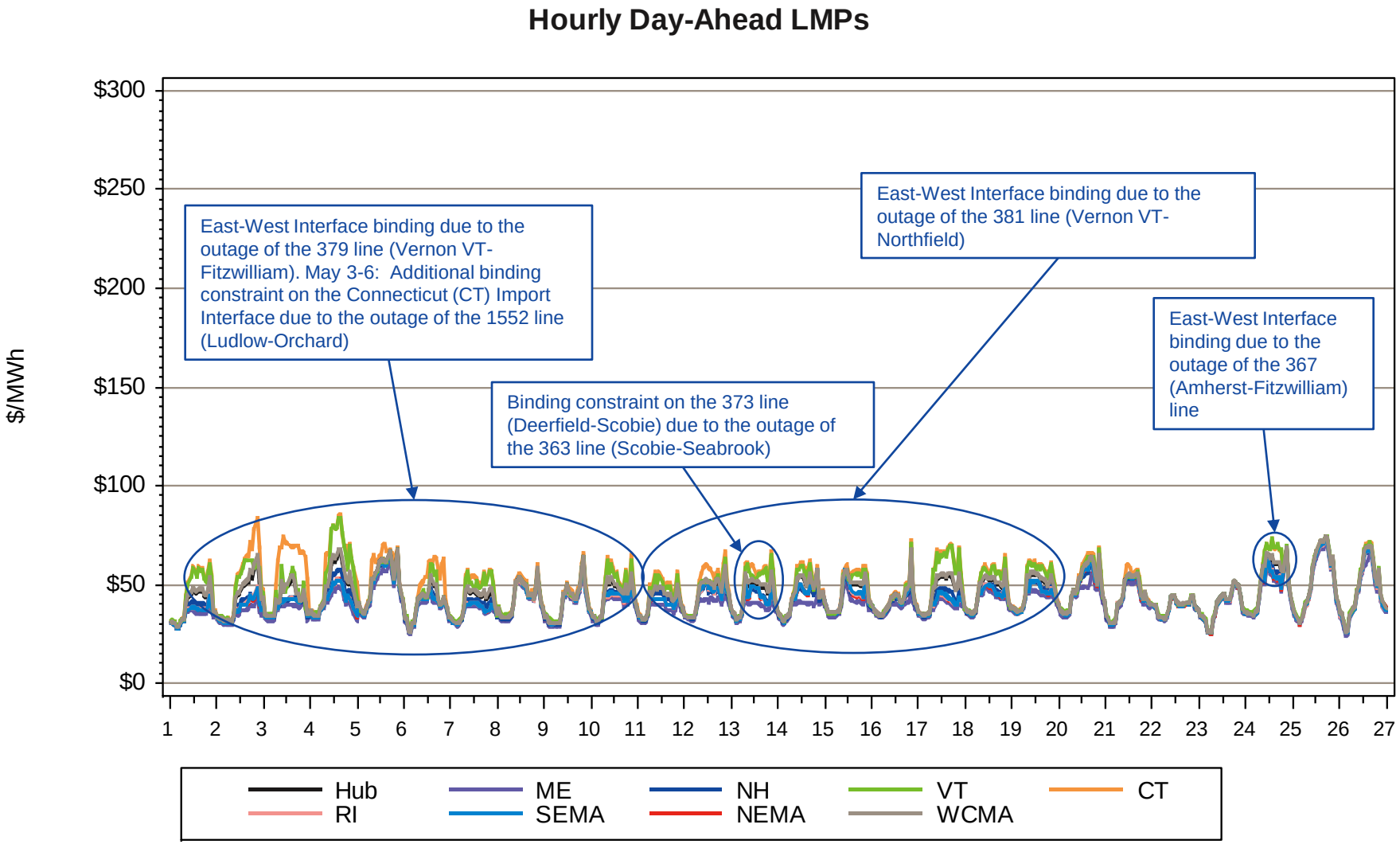
Supply



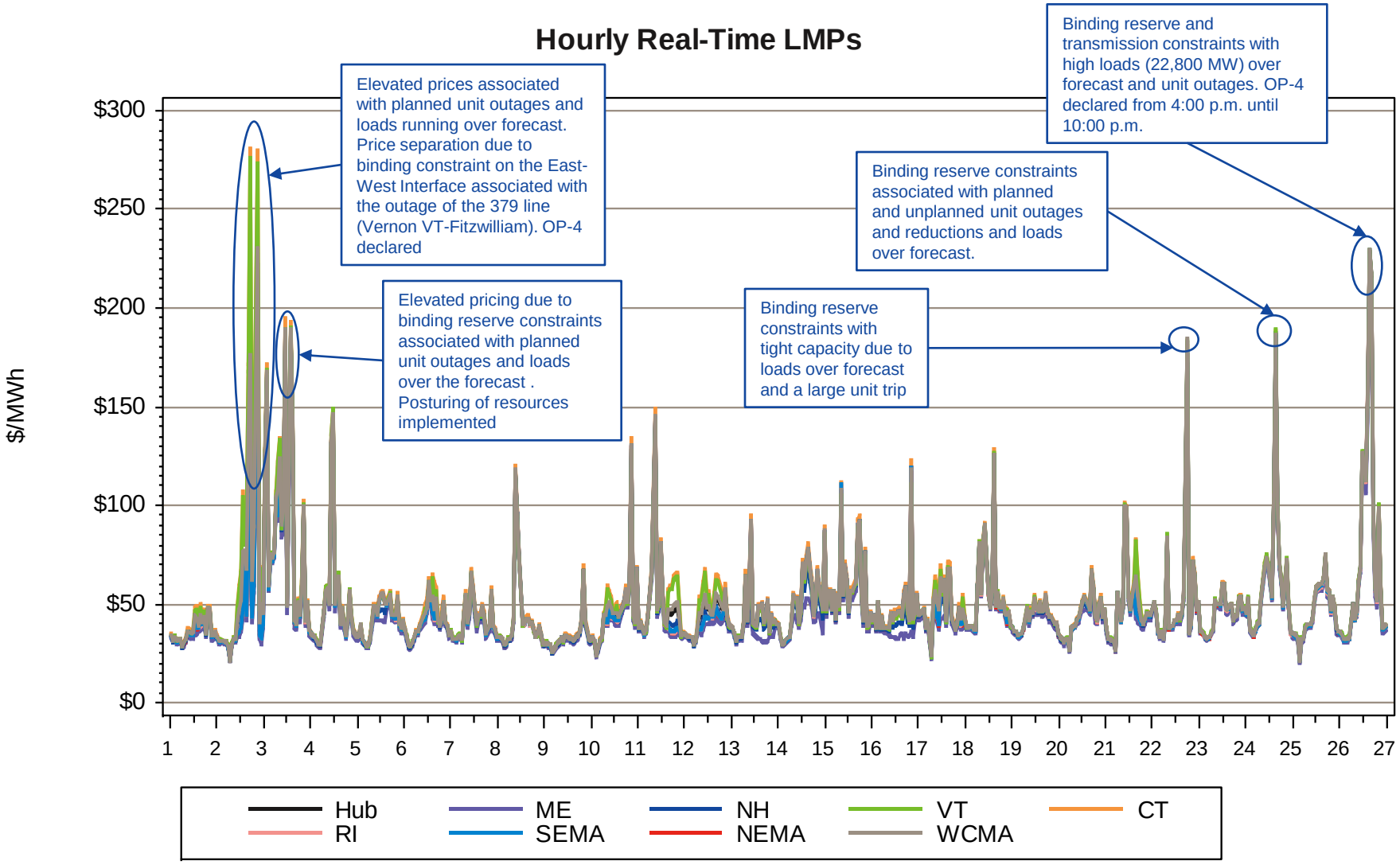
Demand



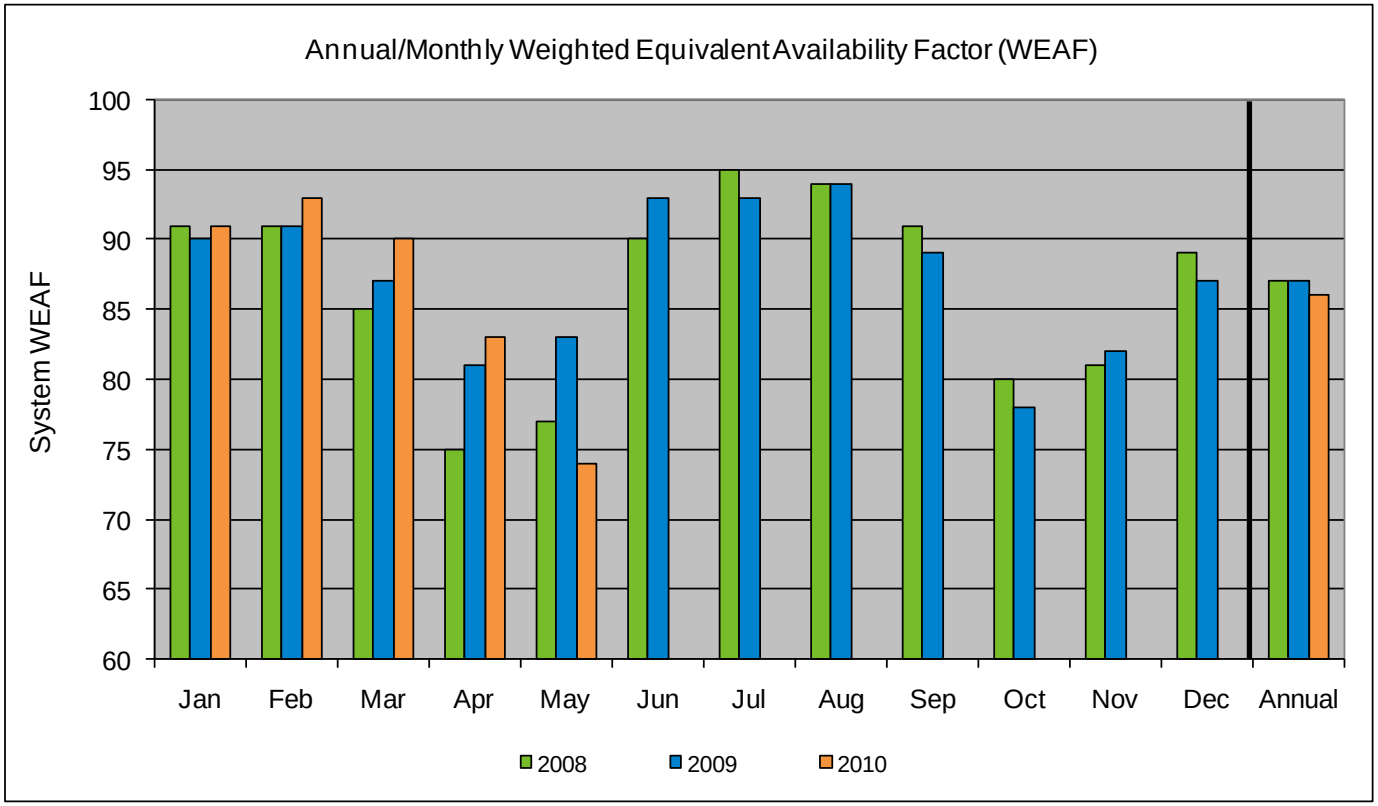
Hourly DA LMPs, May 1-26, 2010



Hourly RT LMPs, May 1-26, 2010



System Unit Availability



Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	YTD	
91	93	90	83	74								86	**2010**
												87	**2009**
												87	**2008**
												90	**2007**

Back-up Detail

Load Response

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

Load Zone	RTDR[1]	RTEG[2]	On Peak	Seasonal Peak	Total
ME	166.22	17.32	21.63	0.00	205.16
NH	29.11	21.57	32.42	0.00	83.10
VT	23.71	11.27	41.74	0.00	76.72
CT	226.83	255.28	59.39	108.53	650.02
RI	27.76	41.84	34.46	0.00	104.06
SEMA	45.23	39.01	61.27	0.00	145.51
WCMA	79.82	58.34	56.89	9.48	204.52
NEMA	70.74	77.77	98.44	0.00	246.95
Total	**669.41**	**522.39**	**406.24**	**118.01**	**1,716.05**

[1] Real-Time Demand Response
[2] Real-Time Demand Response with Emergency Generation
NOTE: Net CSO values exclude T&D loss factor (8%) and reserve margin gross-up (14.3%)

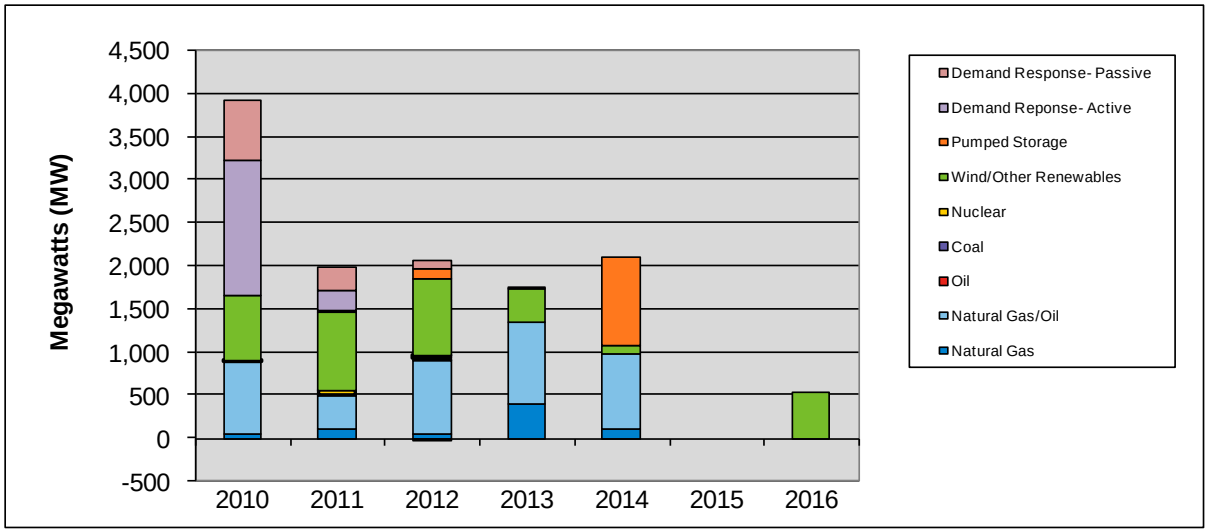
New Generation

New Generation Update

- Ten new generation projects have applied for interconnection study since last month's update, representing a total of 459 MW
  - The new projects are five wind facilities, two biomass plants, and three increases to existing plants (one gas turbine, one combined cycle, and one cogeneration plant)
  - Projected in-service dates are in 2010 through 2014
- One project went commercial and the capacity of one project changed, resulting in a net increase in new generation projects of 500 MW
- In total, 93 generation projects are currently being tracked by the ISO, totaling approximately 9,500 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

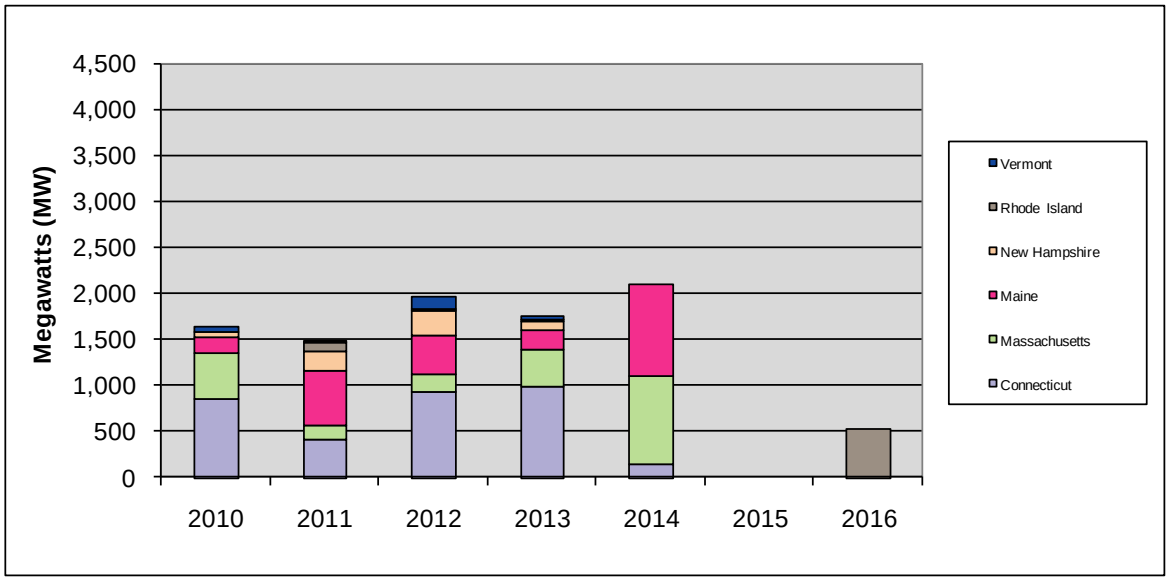


	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Demand Response - Passive	700	278	95	0	0	0	0	1,073	8.7
Demand Response - Active	1,579	221	-6	0	0	0	0	1,794	14.5
Pumped Storage	0	25	111	25	1,025	0	0	1,186	9.6
Wind & Other Renewables	746	905	894	392	91	0	536	3,564	28.7
Nuclear	0	45	0	0	0	0	0	45	0.4
Coal	17	0	36	0	0	0	0	53	0.4
Oil	0	13	30	0	0	0	0	43	0.3
Natural Gas/Oil	838	398	844	934	885	0	0	3,899	31.5
Natural Gas	54	108	60	411	107	0	0	740	6.0
Totals	**3,934**	**1,993**	**2,064**	**1,762**	**2,108**	**0**	**536**	**12,397**	**100.0**

- 2010 values include the 47 MW of generation that has gone commercial in 2010
- Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources

Actual and Projected Annual Generator Capacity Additions

By State



	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Vermont	61	25	129	31	0	0	0	246	2.6
Rhode Island	0	89	34	29	0	0	536	688	7.2
New Hampshire	59	218	267	86	0	0	0	630	6.6
Maine	182	584	412	216	1,000	0	0	2,394	25.1
Massachusetts	492	155	203	405	963	0	0	2,218	23.3
Connecticut	861	423	930	995	145	0	0	3,354	35.2
Totals	**1,655**	**1,494**	**1,975**	**1,762**	**2,108**	**0**	**536**	**9,530**	**100.0**

- 2010 values include the 47 MW of generation that has gone commercial in 2010

New Generation Projection
By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	13	429	1	38	12	391
Coal	2	53	0	0	2	53
Hydro	9	1,219	0	24	9	1,195
Landfill Gas	2	36	0	0	2	36
Natural Gas	12	740	1	0	11	740
Natural Gas/Oil	16	3,878	4	1,140	12	2,738
Nuclear Uprates	2	45	0	0	2	45
Oil	2	43	0	0	2	43
Solar	1	20	0	0	1	20
Wind	34	3,020	4	180	30	2,840
Total	93	9,483	10	1,382	83	8,101

- 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	20	572	1	38	19	534
Intermediate	18	3,580	1	644	17	2,936
Peaker	21	2,311	4	520	17	1,791
Wind Turbine	34	3,020	4	180	30	2,840
Total	93	9,483	10	1,382	83	8,101

- 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	13	429	13	429	0	0	0	0	0	0
Coal	2	53	2	53	0	0	0	0	0	0
Hydro	9	1,219	0	0	5	32	4	1,187	0	0
Landfill Gas	2	36	2	36	0	0	0	0	0	0
Natural Gas	12	740	1	9	4	667	7	64	0	0
Natural Gas/Oil	16	3,878	0	0	9	2,881	7	997	0	0
Nuclear Uprates	2	45	2	45	0	0	0	0	0	0
Oil	2	43	0	0	0	0	2	43	0	0
Solar	1	20	0	0	0	0	1	20	0	0
Wind	34	3,020	0	0	0	0	0	0	34	3,020
Total	93	9,483	20	572	18	3,580	21	2,311	34	3,020

Capacity Supply Obligations (CSO) FCA 1

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

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

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

Reliability Costs

Net Commitment Period Compensation (NCPC) Operating Costs

What are Daily NCPC Payments?

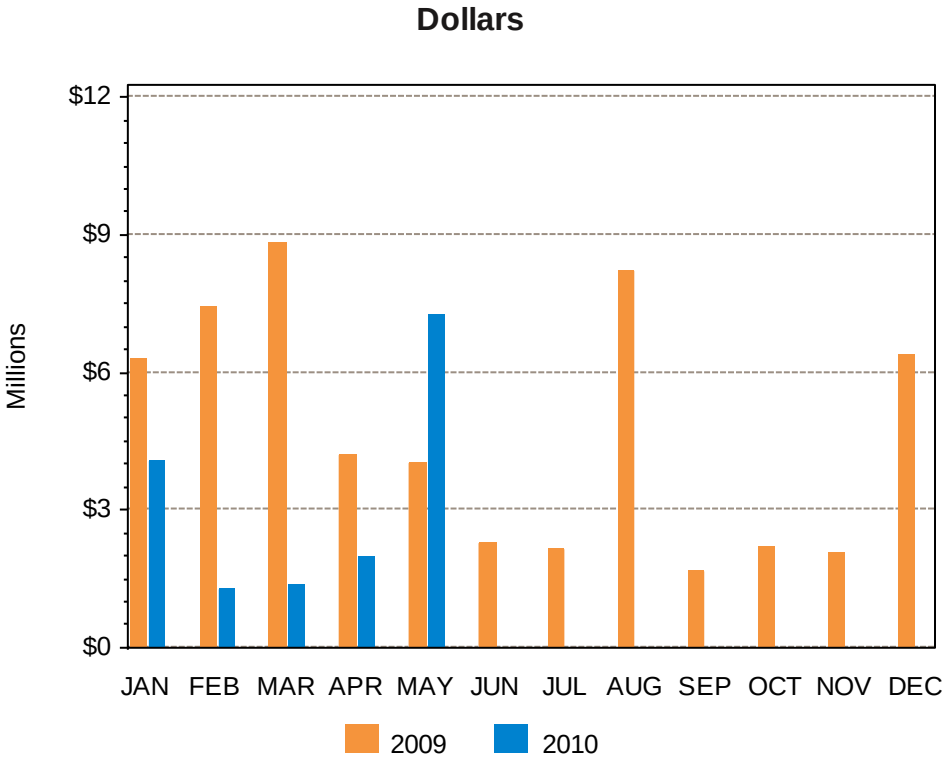
- "Make-whole" payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day

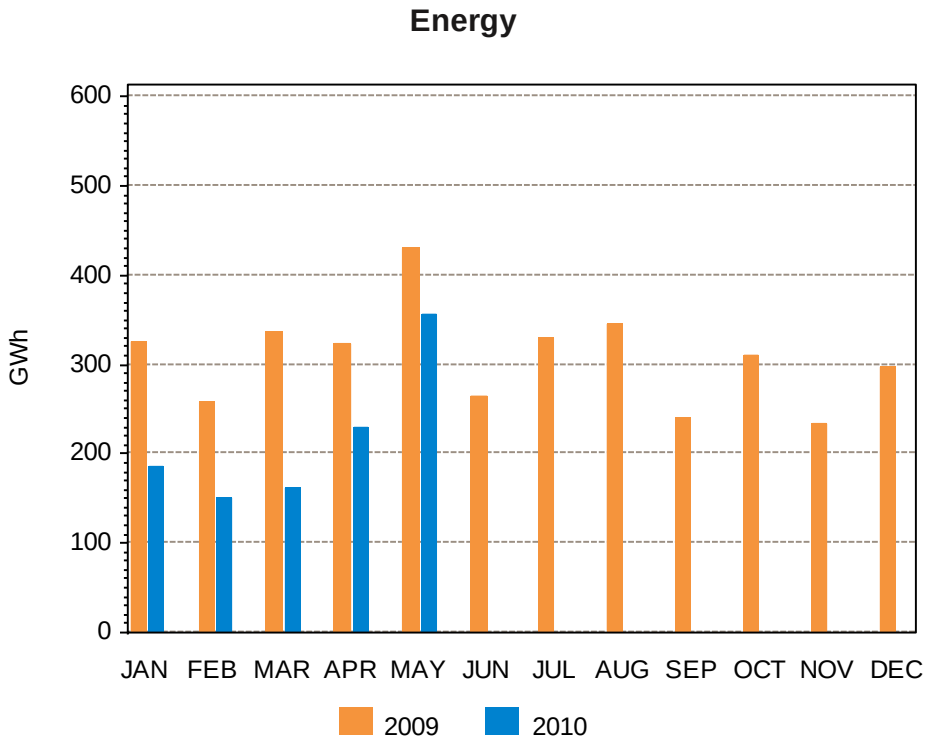
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area

Definitions

Voltage NCPC Payments	Reliability costs paid to resources operated by the ISO-NE to provide voltage control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are not providing 2nd 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 2nd 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

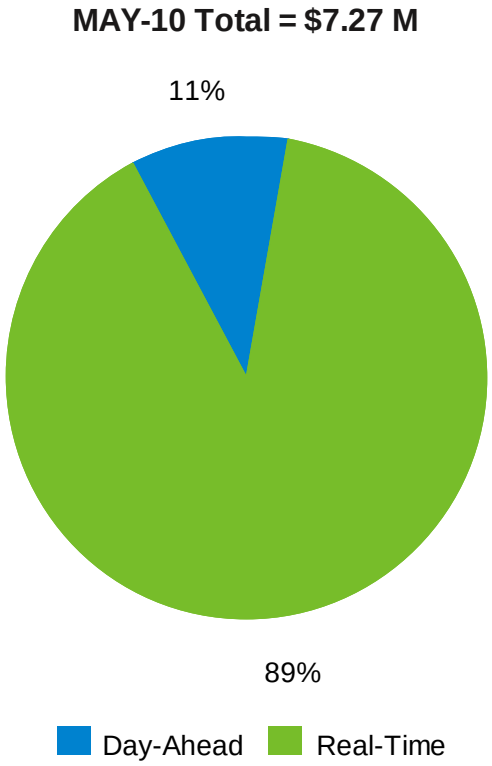


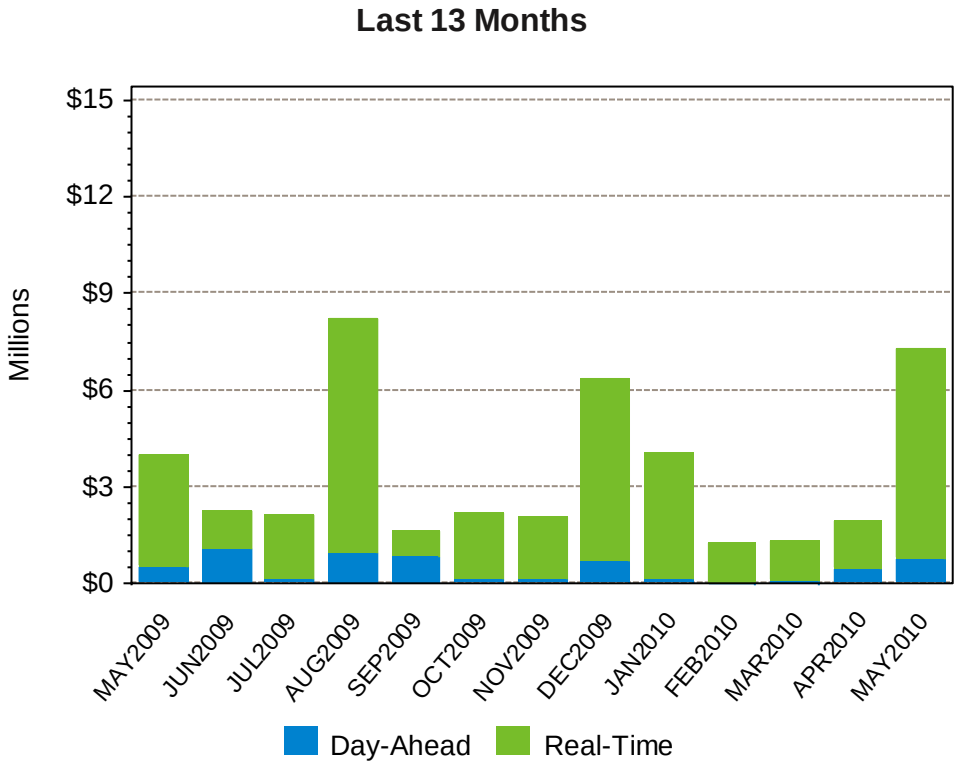


Note:

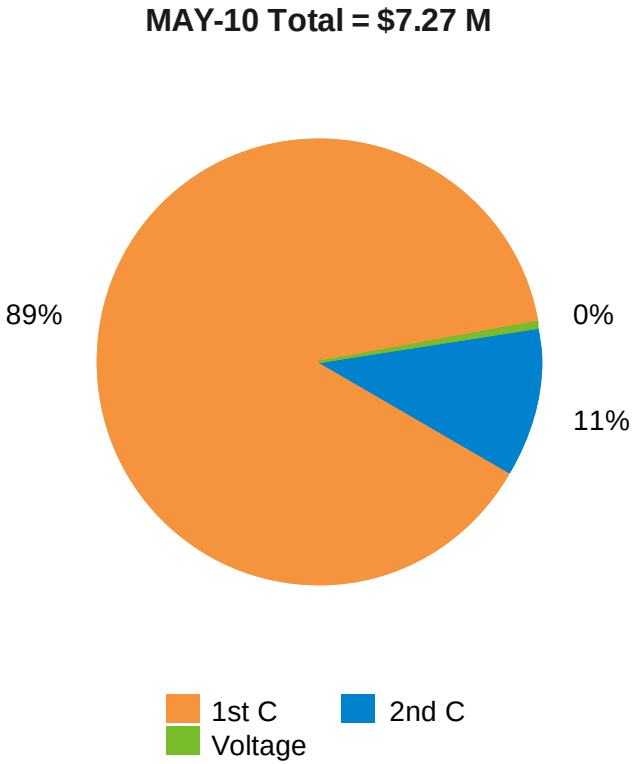
- Overall Reliability Cost MWh includes out of merit DA and RT 1st Contingency, 2nd Contingency, Voltage, and RT Distribution components.
- Energy includes daily totals of cleared DA energy and RT energy from resources receiving NCPC payments.

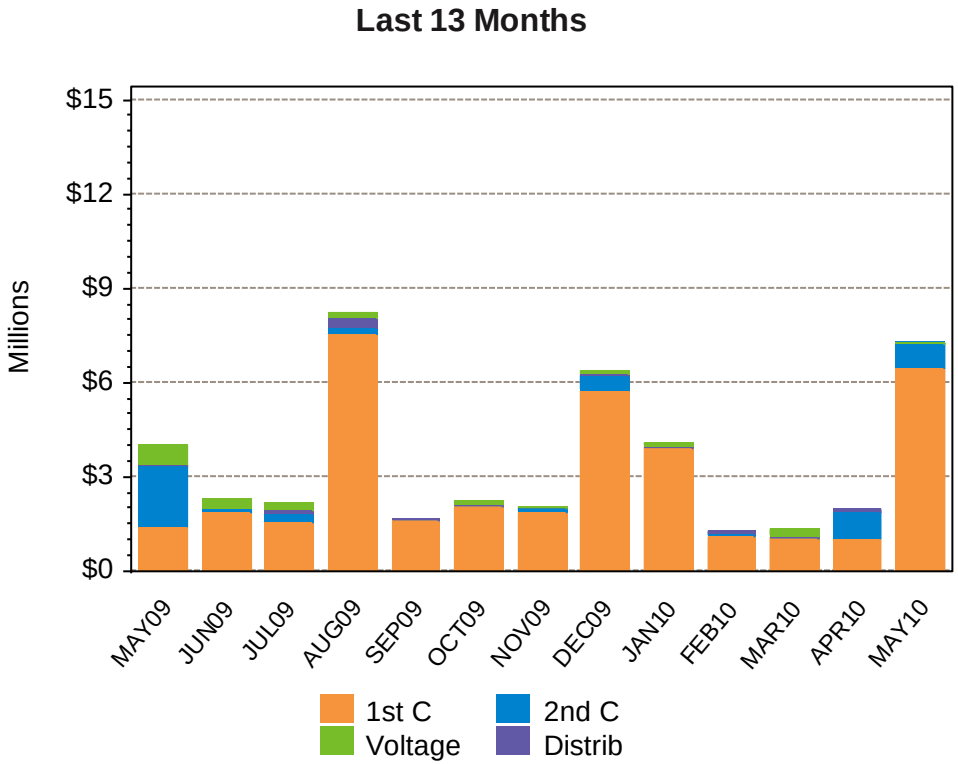
DA and RT NCPC Payments





NCPC Payments by Type

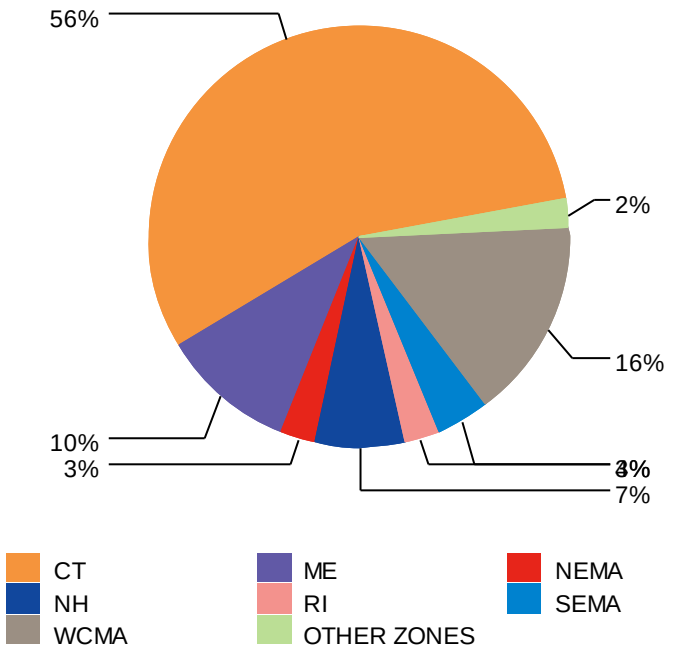




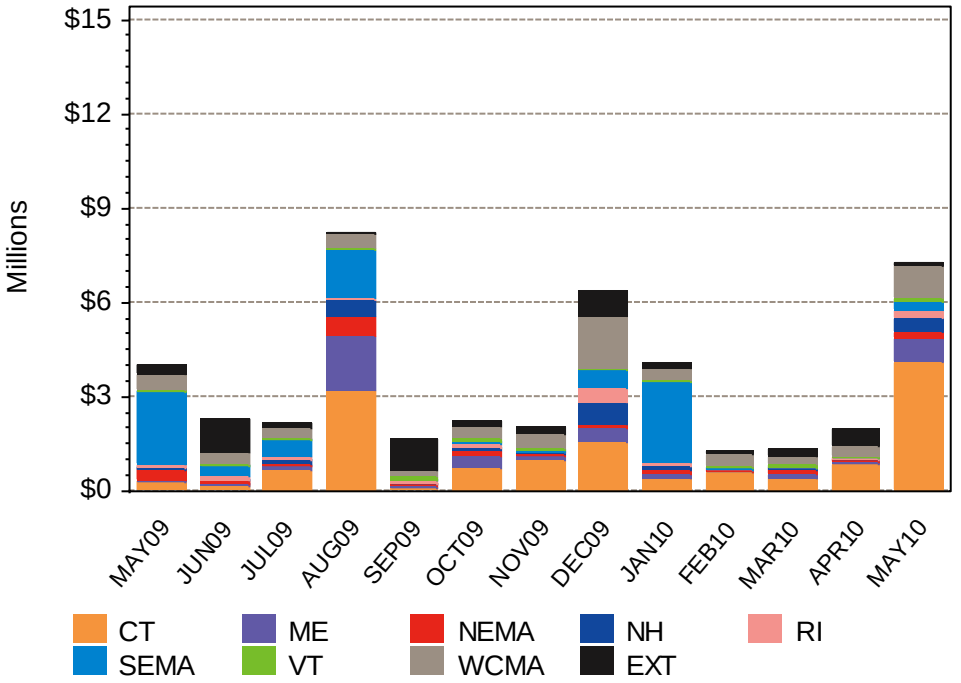
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage Support

NCPC Payments by Location

MAY-10 Total = $7.27 M



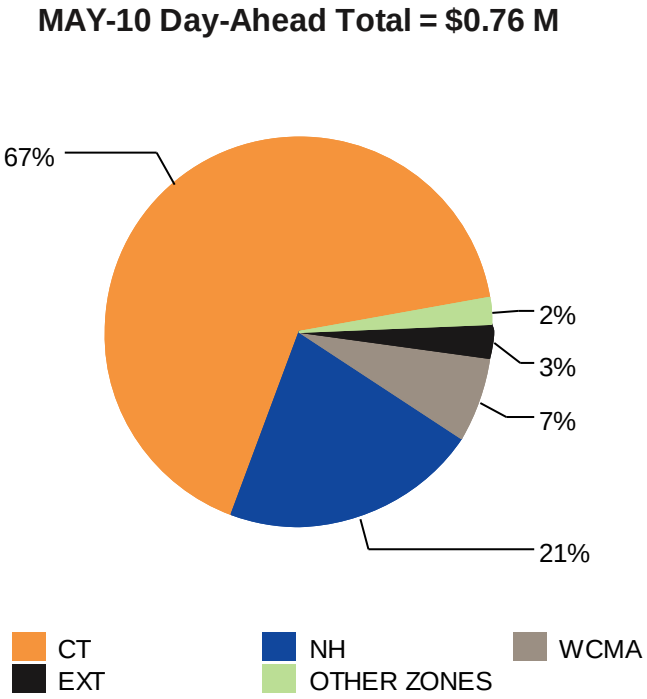
Last 13 Months

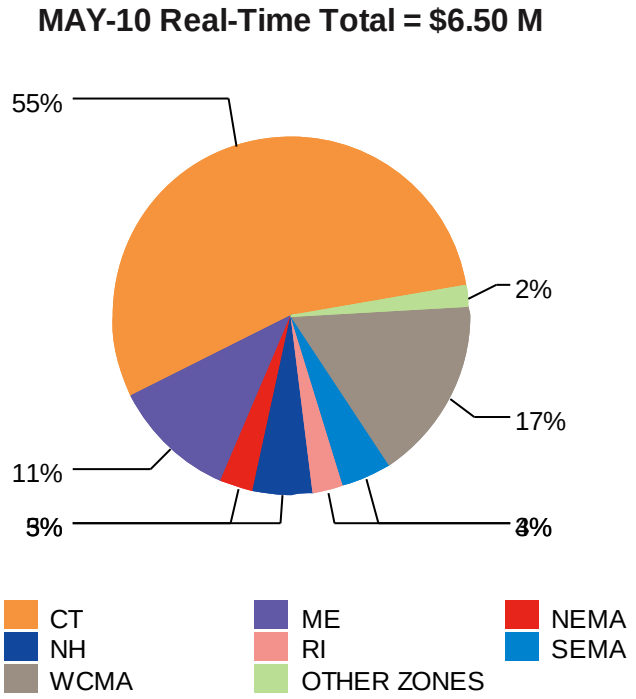


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region

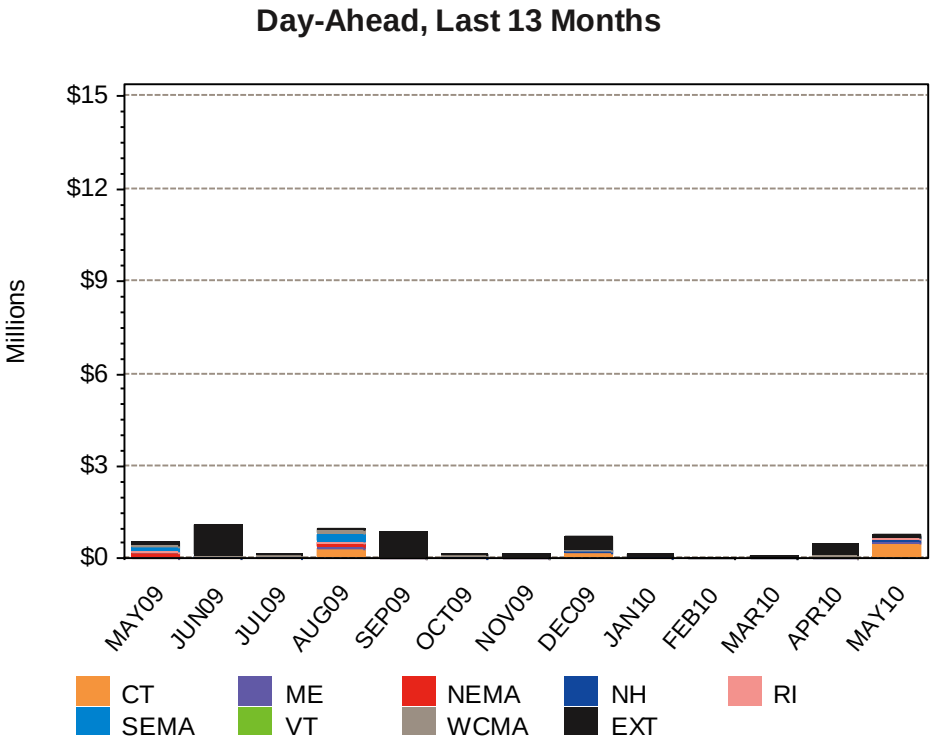
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

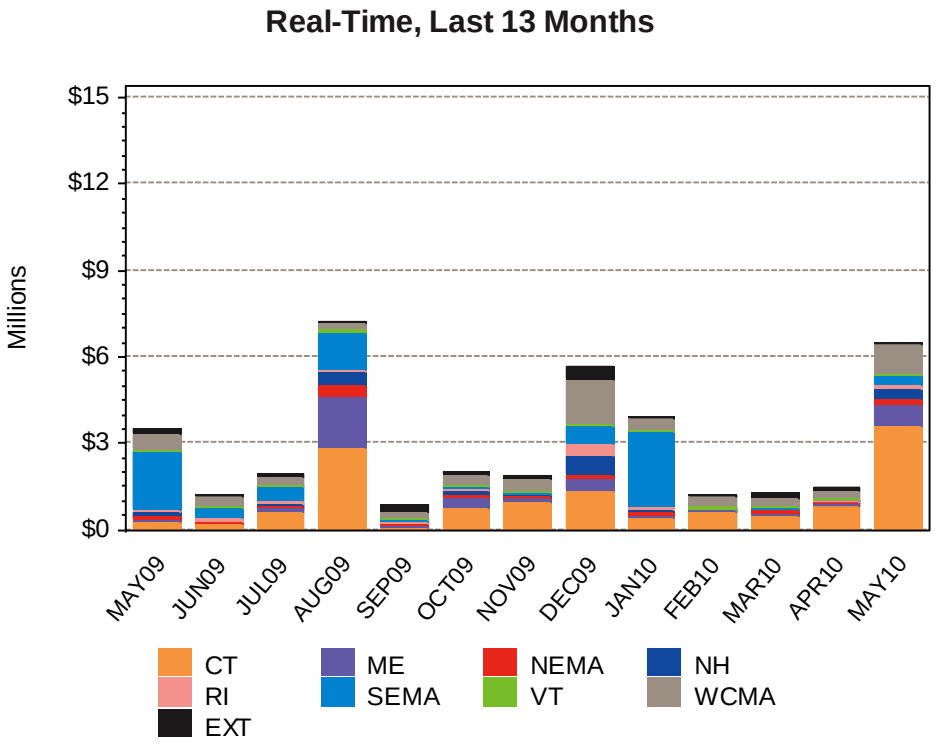
DA and RT NCPC Payments by Location



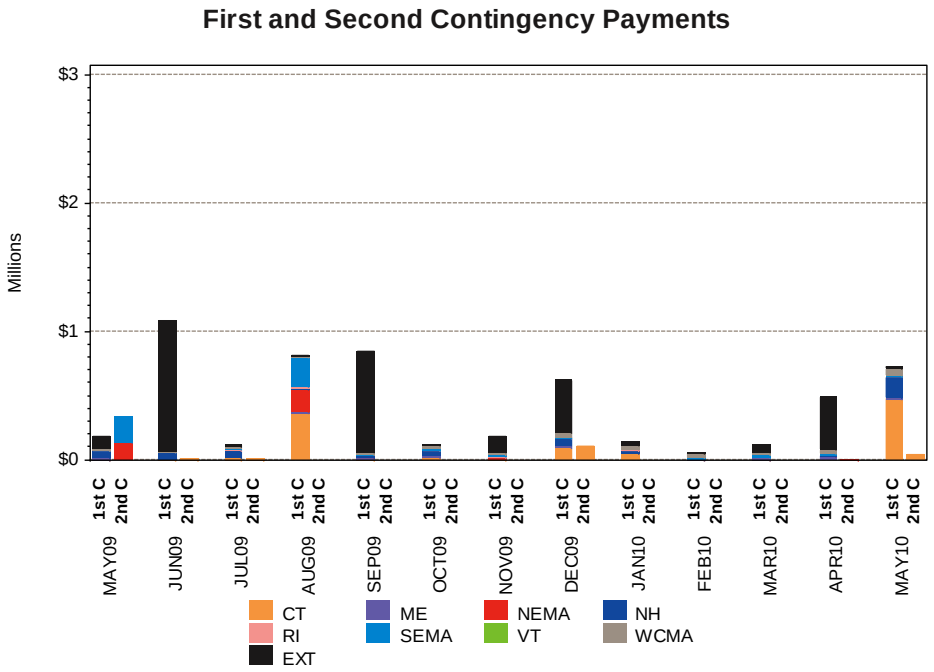


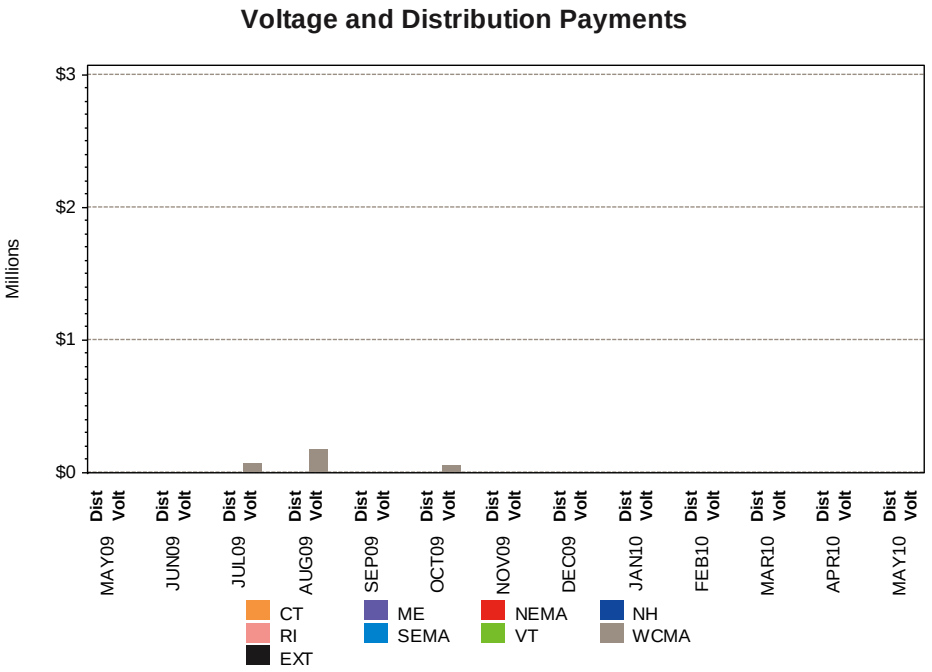
DA and RT NCPC Payments by Location, Last 13 Months



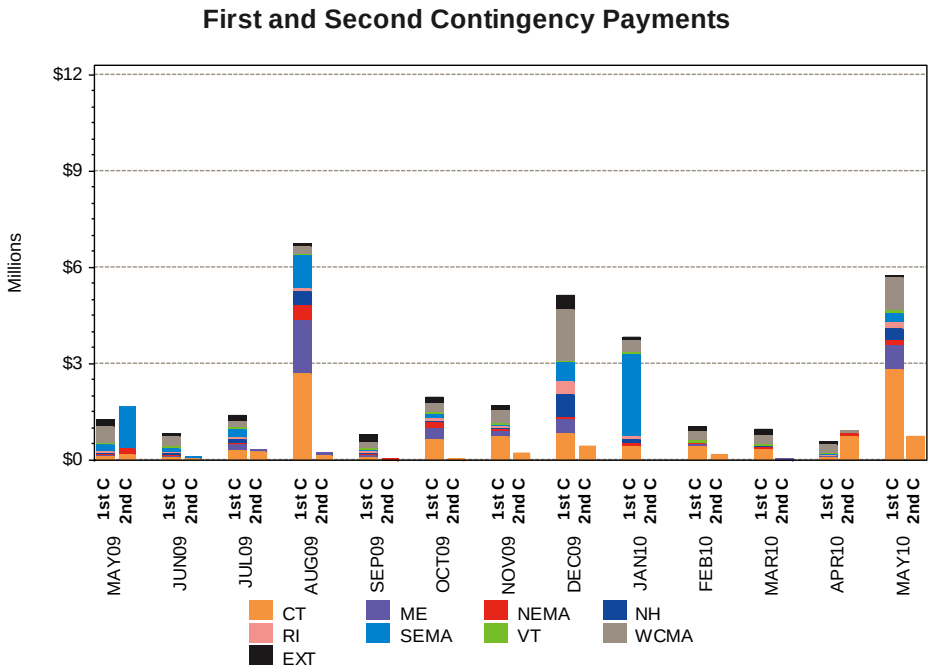


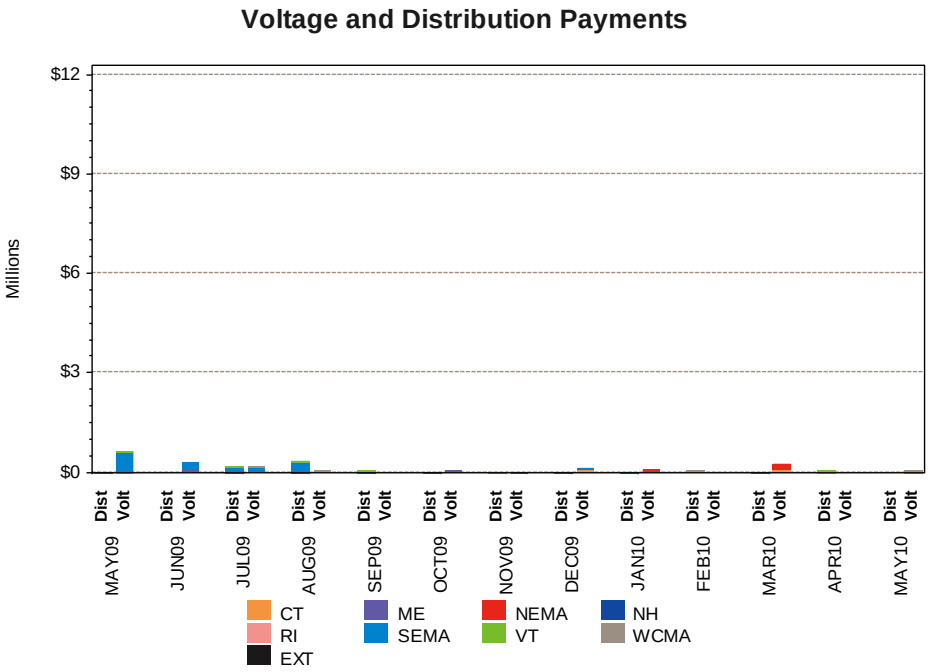
DA NCPC Payments by Type and Location



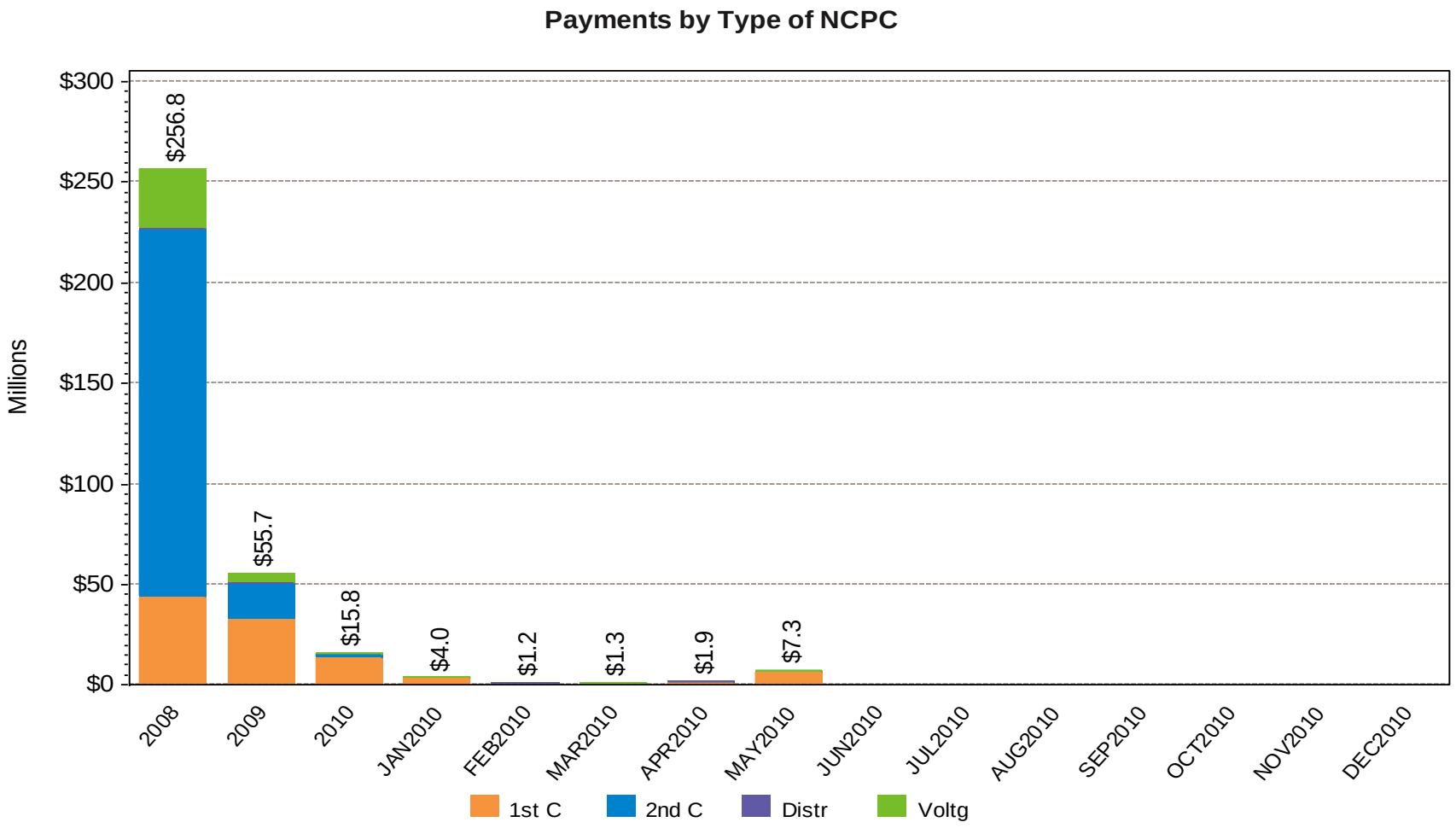


RT NCPC Payments by Type and Location

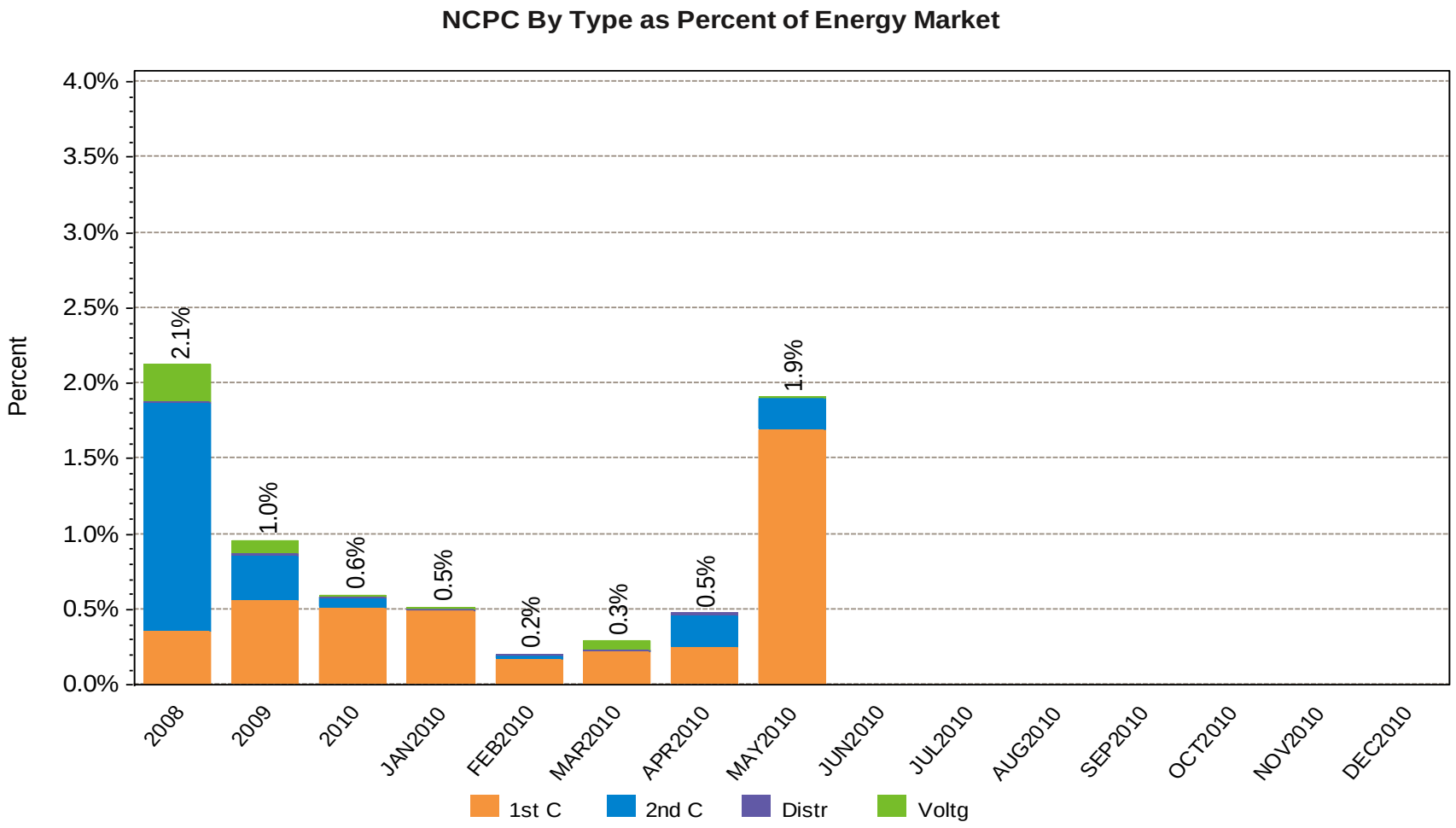




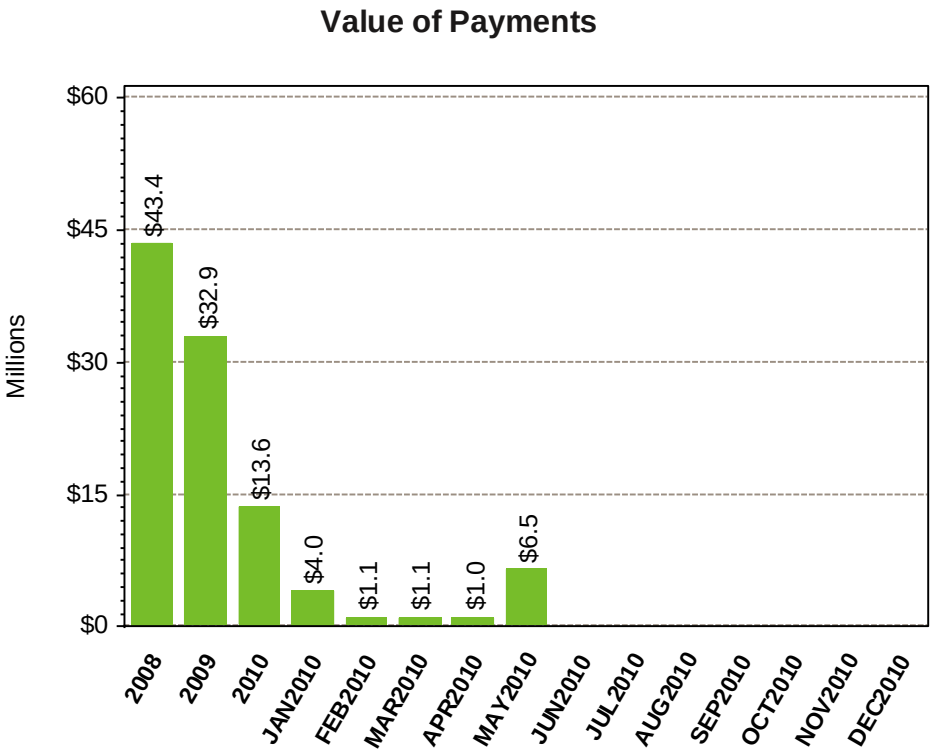
NCPC Payments by Type

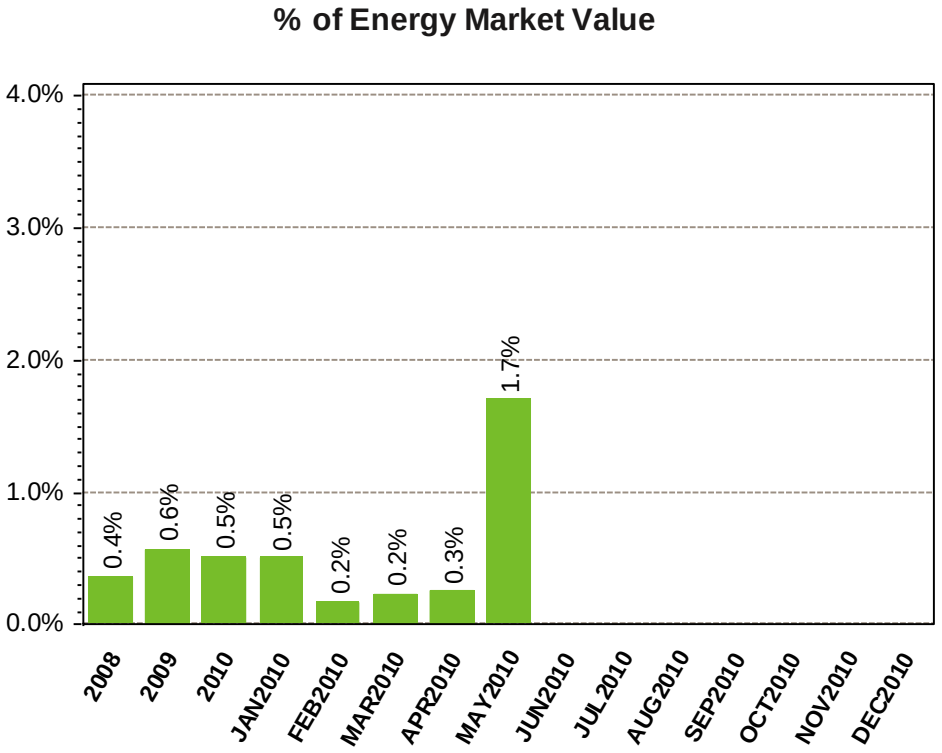


NCPC Payments by Percent of Energy Market



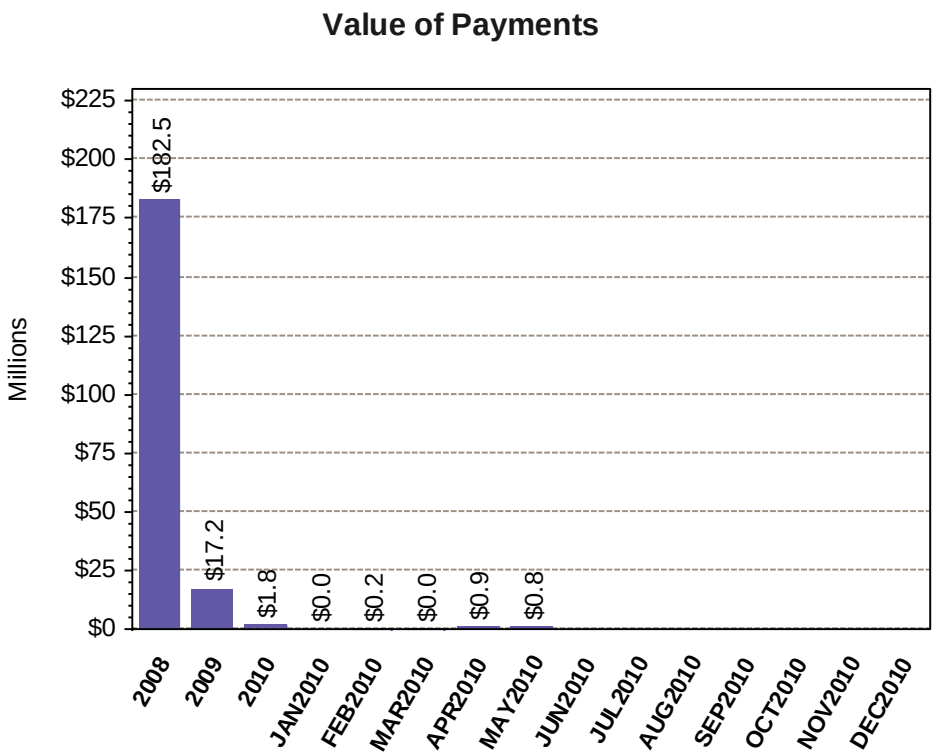
First Contingency NCPC Payments

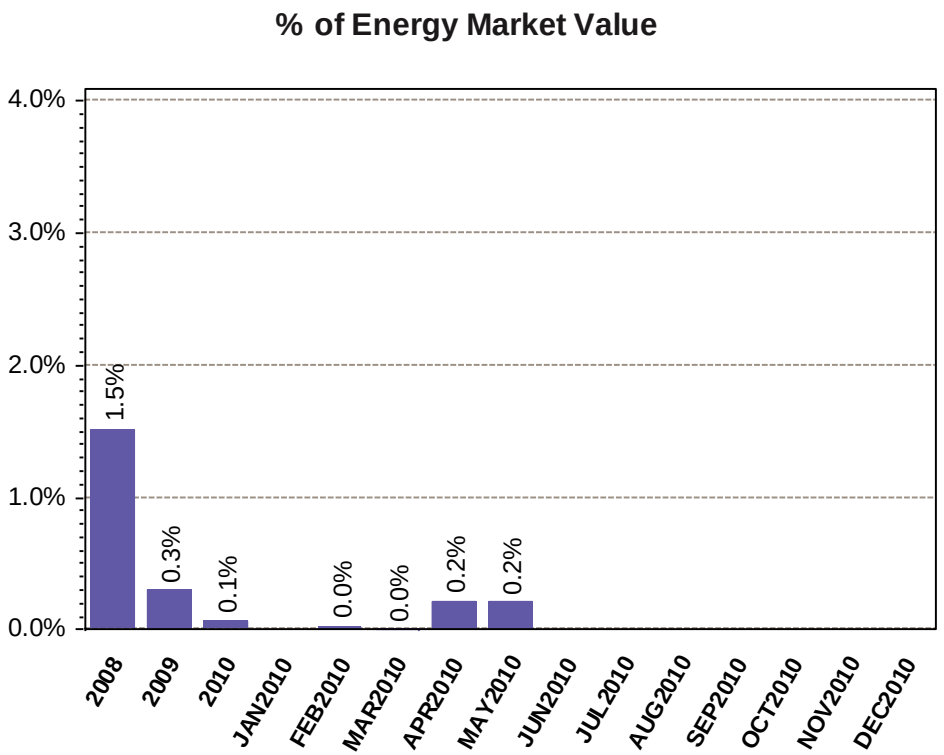




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

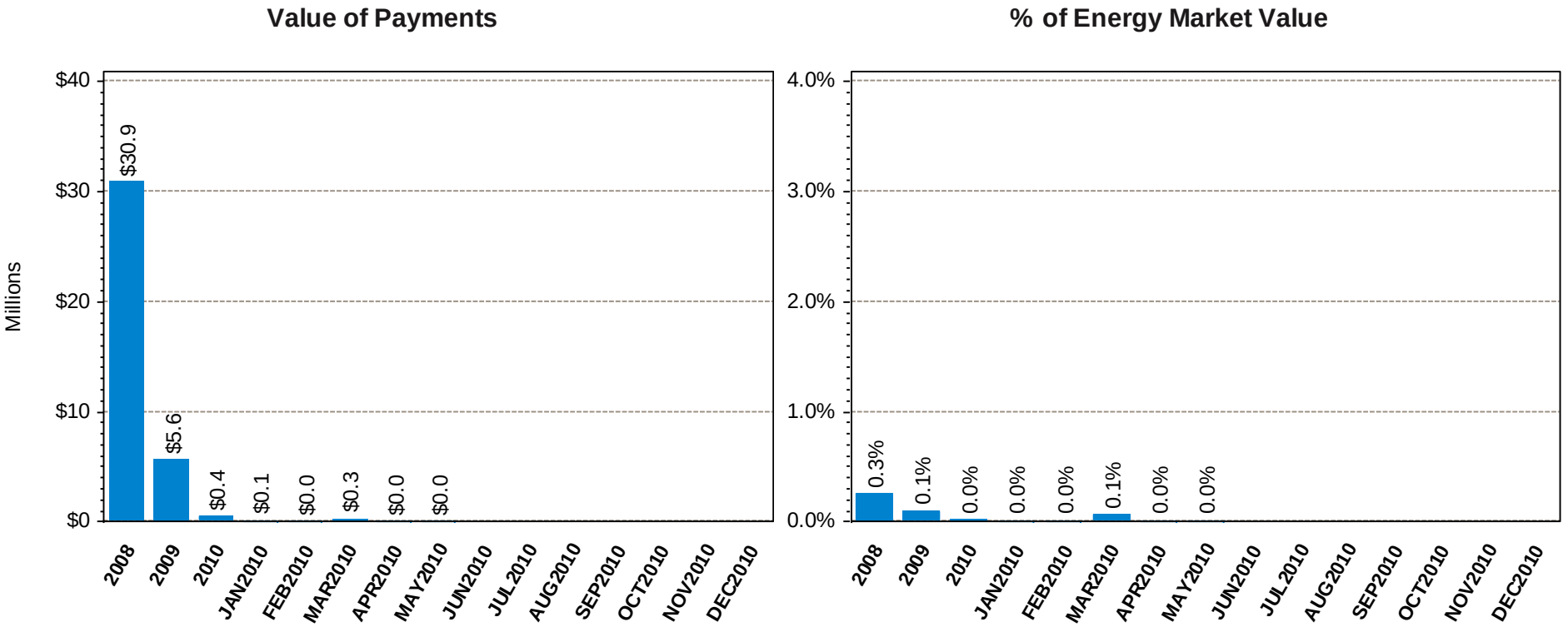
Second Contingency NCPC Payments





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



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

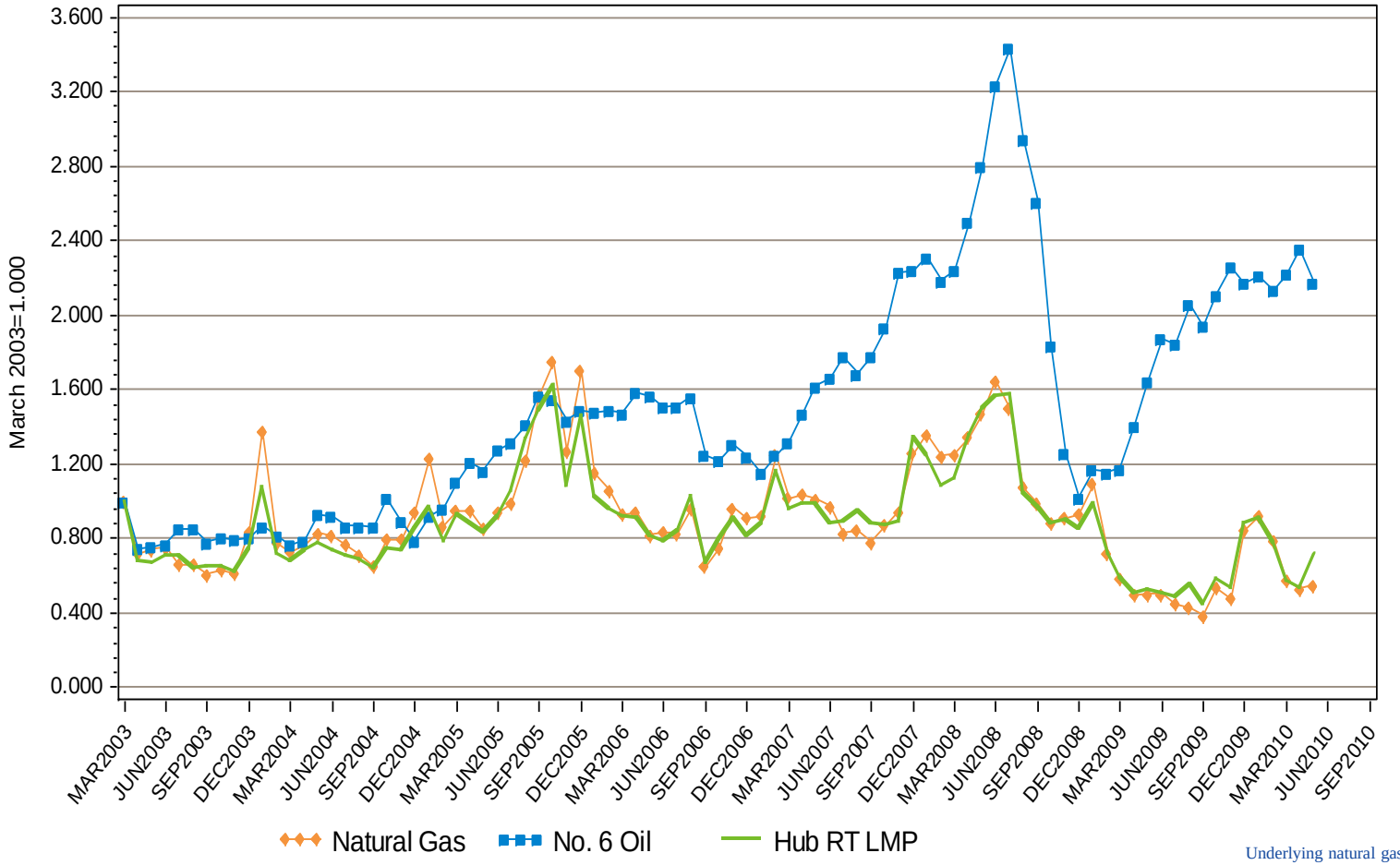
DA vs. RT LMPs ($/MWh)

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%

May-09	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$36.26	$37.36	$34.39	$35.31	$35.73	$36.12	$37.46	$36.66	$36.39
Real-Time	$36.50	$36.58	$34.13	$35.11	$35.65	$36.00	$37.17	$36.45	$36.30
RT Delta %	0.7%	-2.1%	-0.8%	-0.6%	-0.2%	-0.3%	-0.8%	-0.6%	-0.2%
May-10	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$41.79	$48.48	$39.76	$42.29	$46.83	$42.03	$41.97	$44.80	$44.31
Real-Time	$48.32	$51.96	$45.03	$47.94	$50.96	$48.41	$48.53	$49.99	$49.56
RT Delta %	15.6%	7.2%	13.3%	13.4%	8.8%	15.2%	15.6%	11.6%	11.8%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	15.3%	29.8%	15.6%	19.8%	31.1%	16.4%	12.1%	22.2%	21.7%
Yr over Yr RT	32.4%	42.0%	31.9%	36.6%	42.9%	34.5%	30.6%	37.1%	36.5%

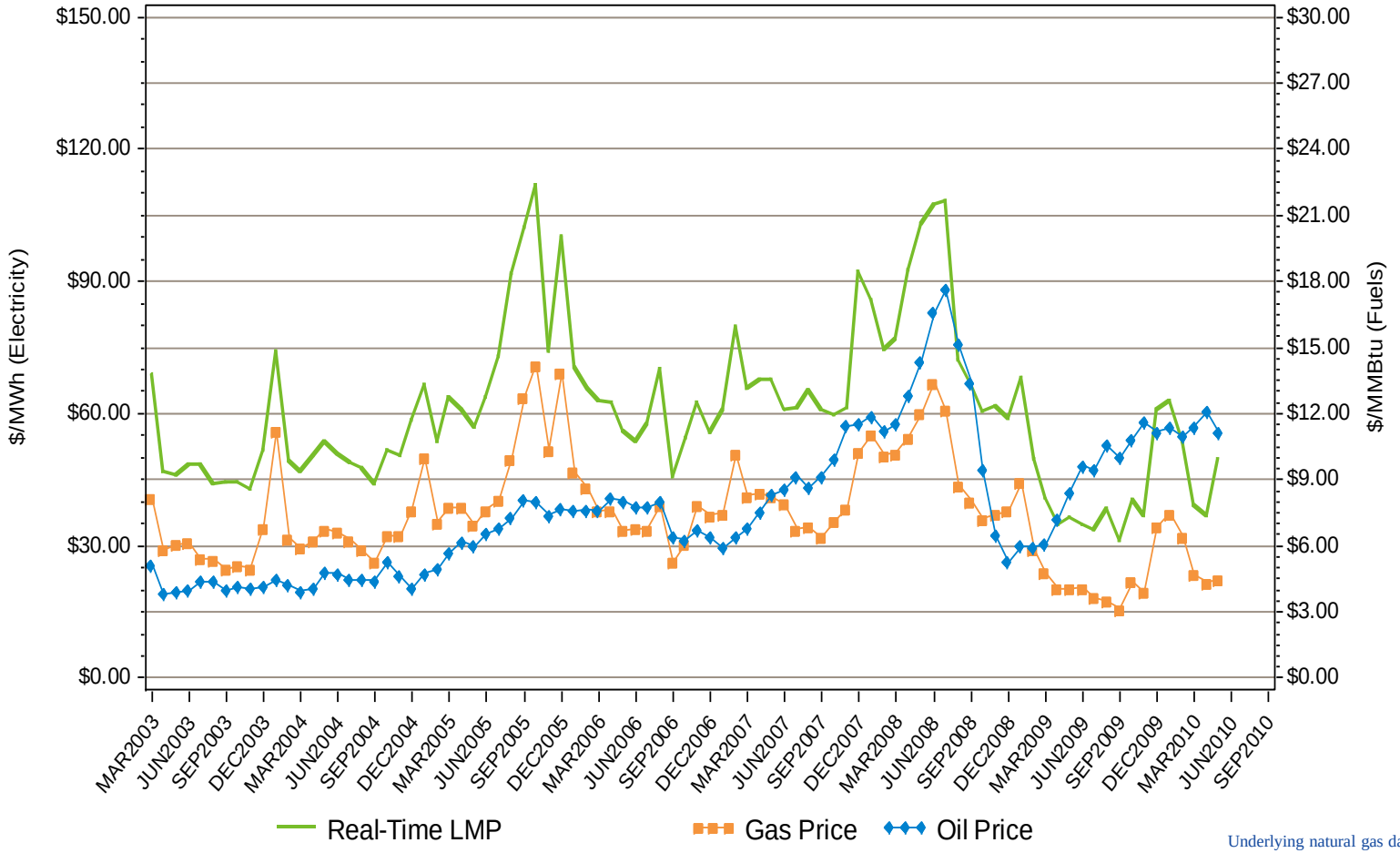
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP



Underlying natural gas data furnished by:

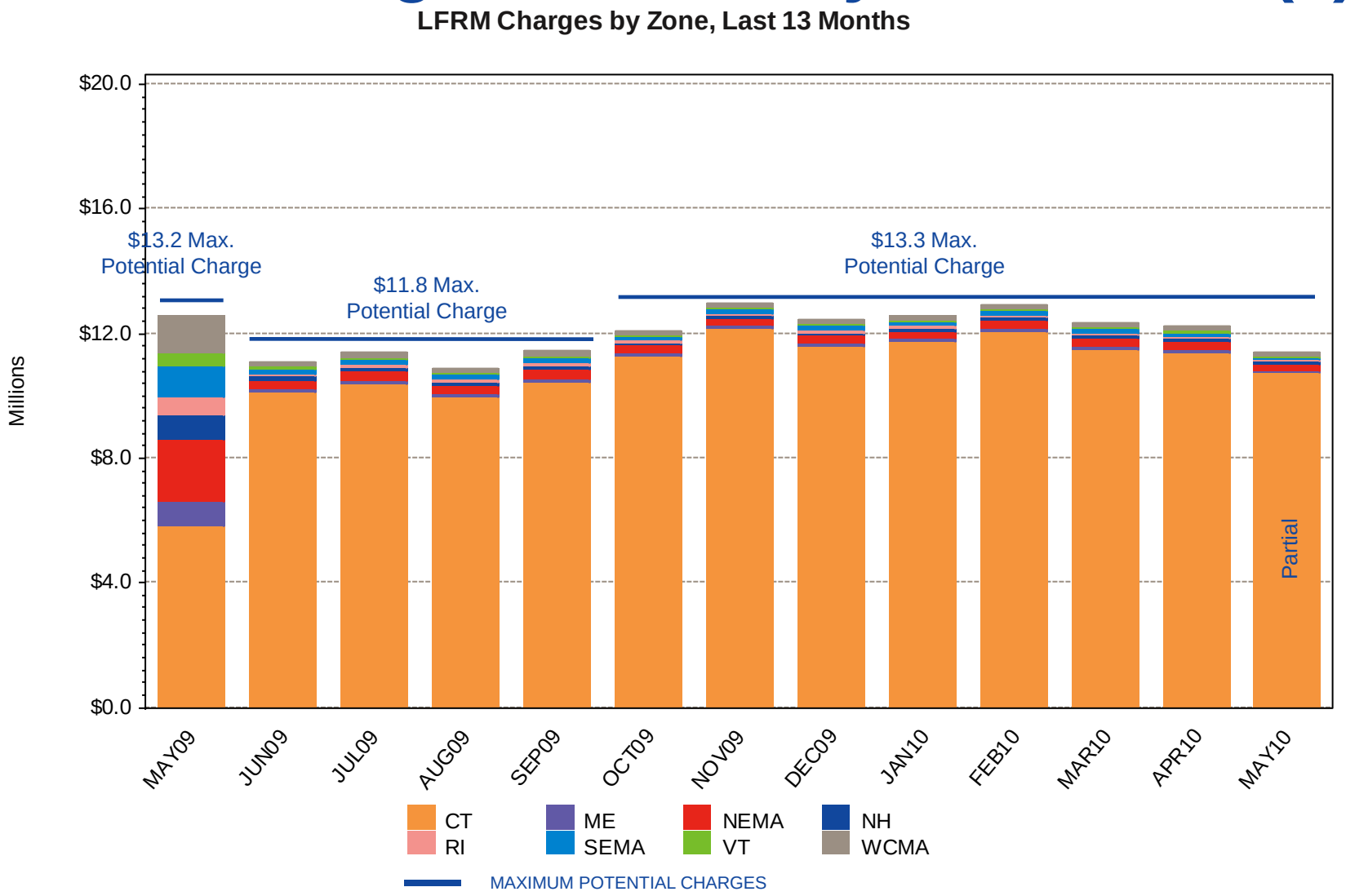
ICE Global markets in clear view

Reserve Market Results – May 2010

- Maximum potential Forward Reserve Market payments of $11.9M were reduced by credit reductions of $220K, failure-to-reserve penalties of $327K and failure-to-activate penalties of $0, resulting in a net payout of $11.4M or 95% of maximum
  - Rest of System: $1.20M/$1.52M (79%)
  - Southwest Connecticut: $3.77M/$3.80M (99%)
  - Connecticut: $6.42M/$6.63M (97%)
  - NEMA: n/a
- $3.6M total Real-Time credits were reduced by $553K in Forward Reserve Energy Obligation Charges for a net of $3.0M in Real-Time Reserve payments
  - Rest of System: 340 hours, $2,265K
  - Southwest Connecticut: 344 hours, $186K
  - Connecticut: 344 hours, $328K
  - NEMA: 340 hours, $257K
- The system reserve bias factor was used for Thirty-Minute Operating Reserve for approximately one hour on May 2, ten minutes on May 8, and approximately 6 hours on May 20.

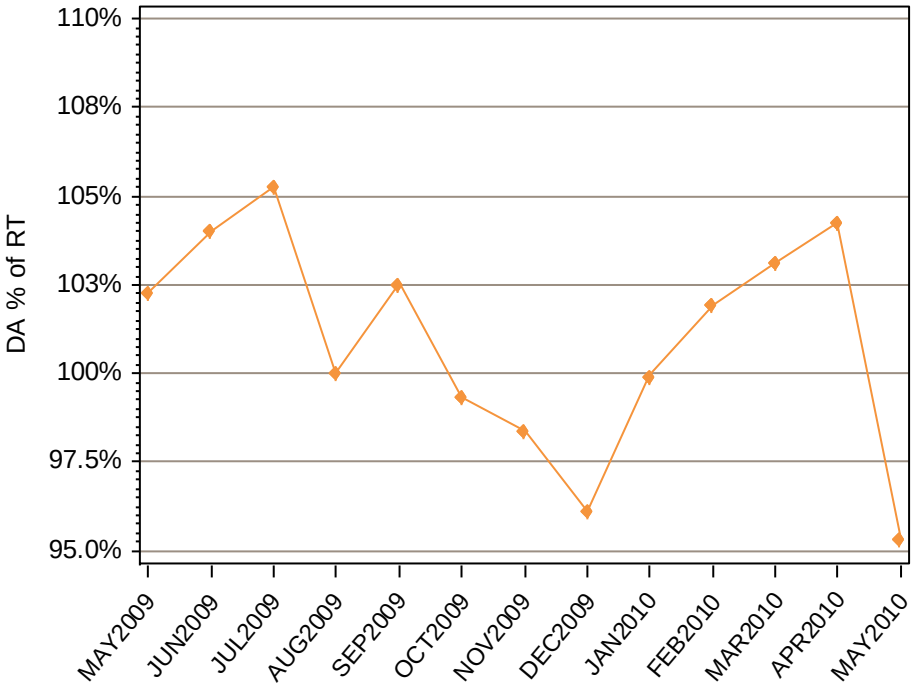
* "Failure to reserve" results in both reductions in credits and penalties in the Locational Forward Reserve Market.

LFRM Charges to Load by Load Zone ($)

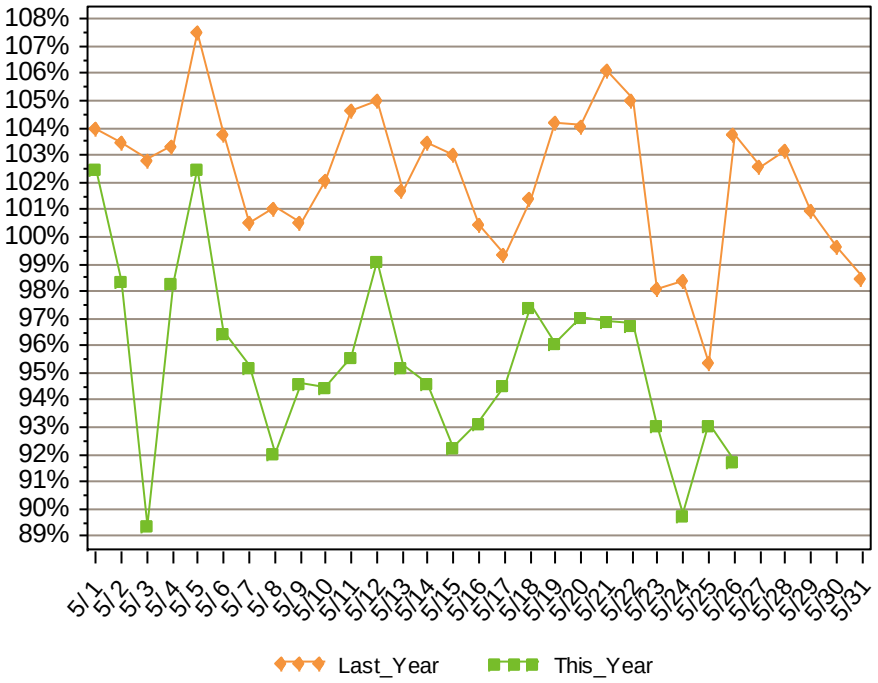


DA Load Obligation Percent of RT Load Obligation

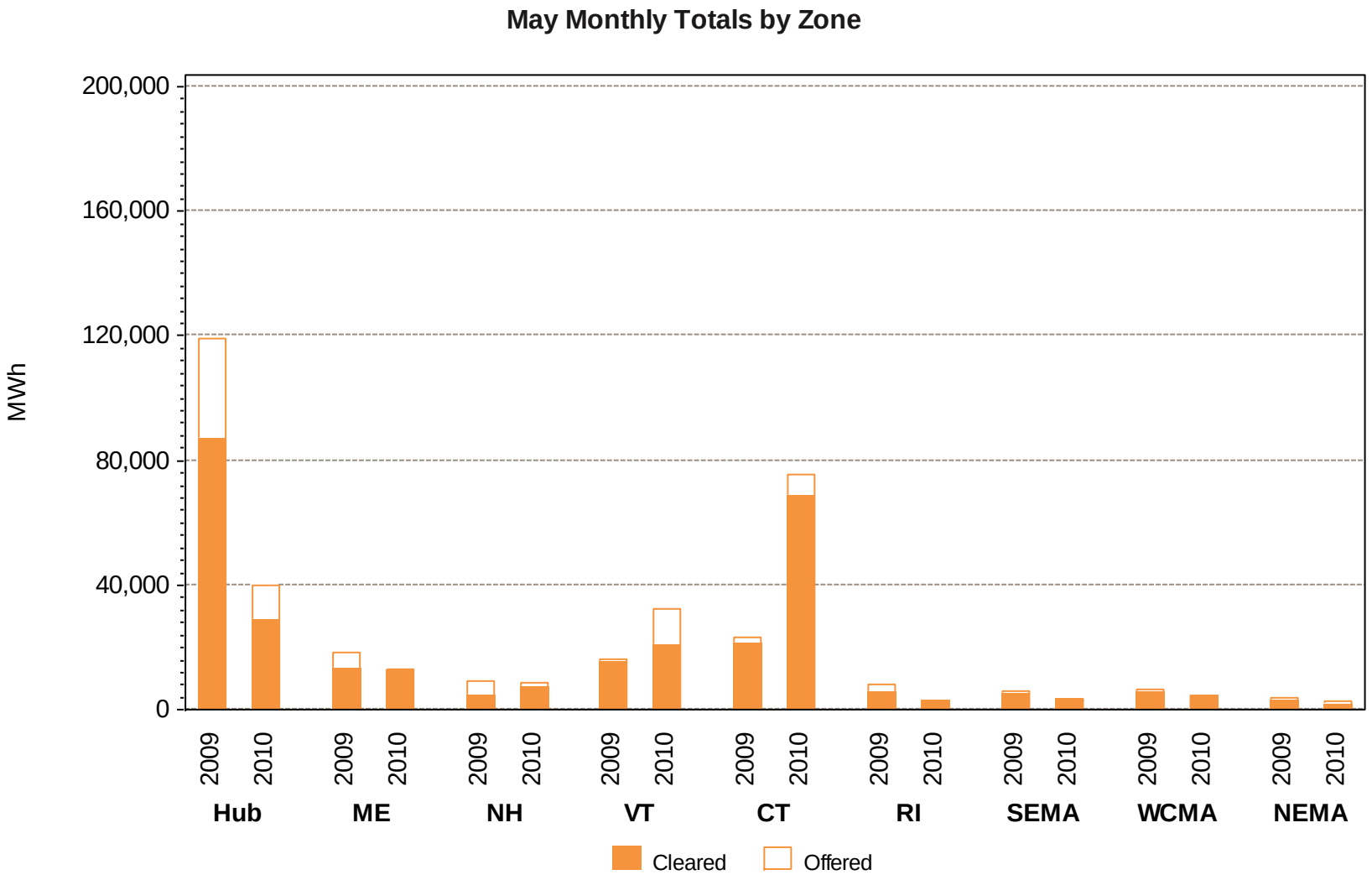
Monthly, Last 13 Months



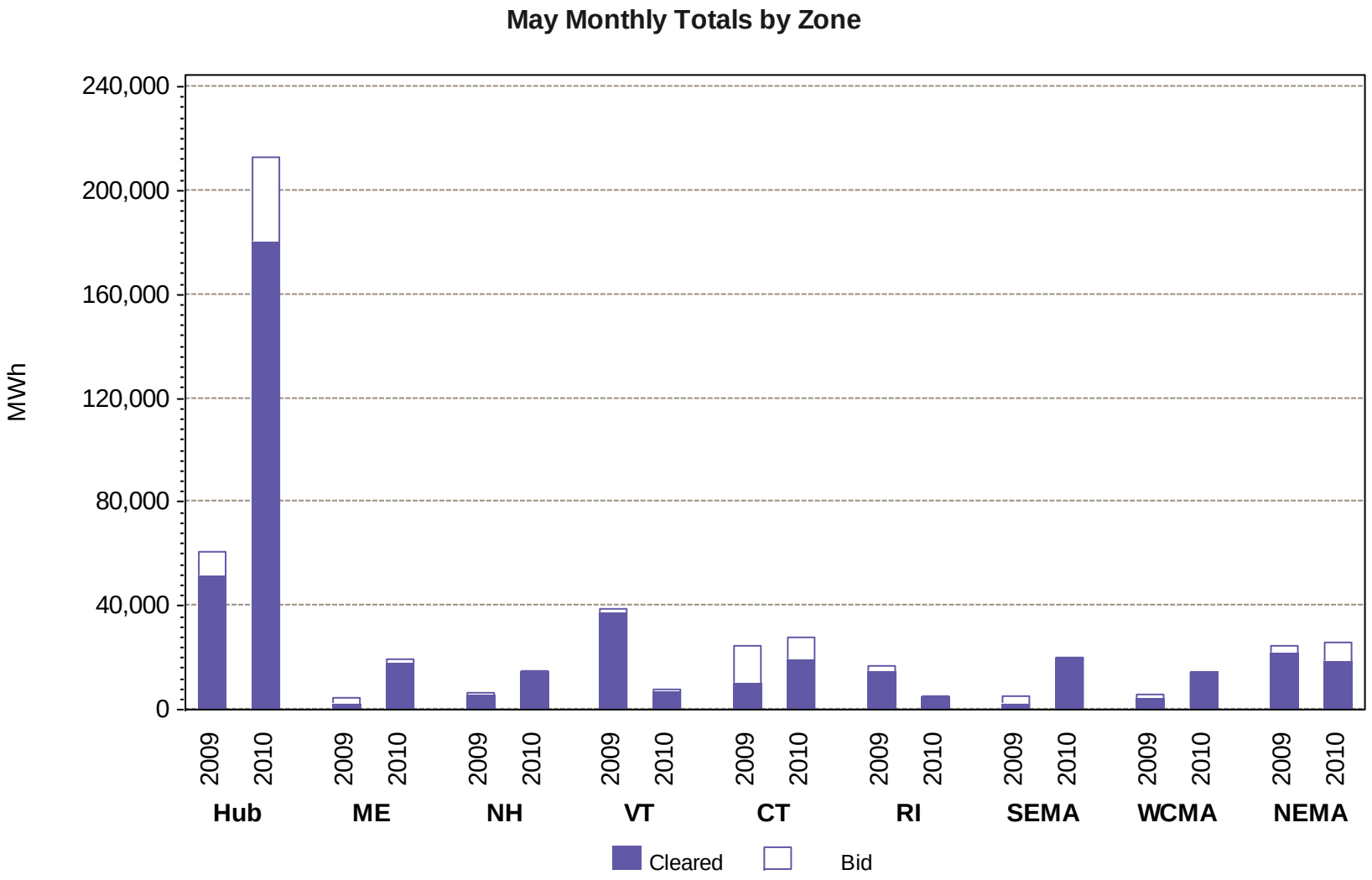
Daily, This Year vs. Last Year



Zonal Increment Offers and Cleared Amounts

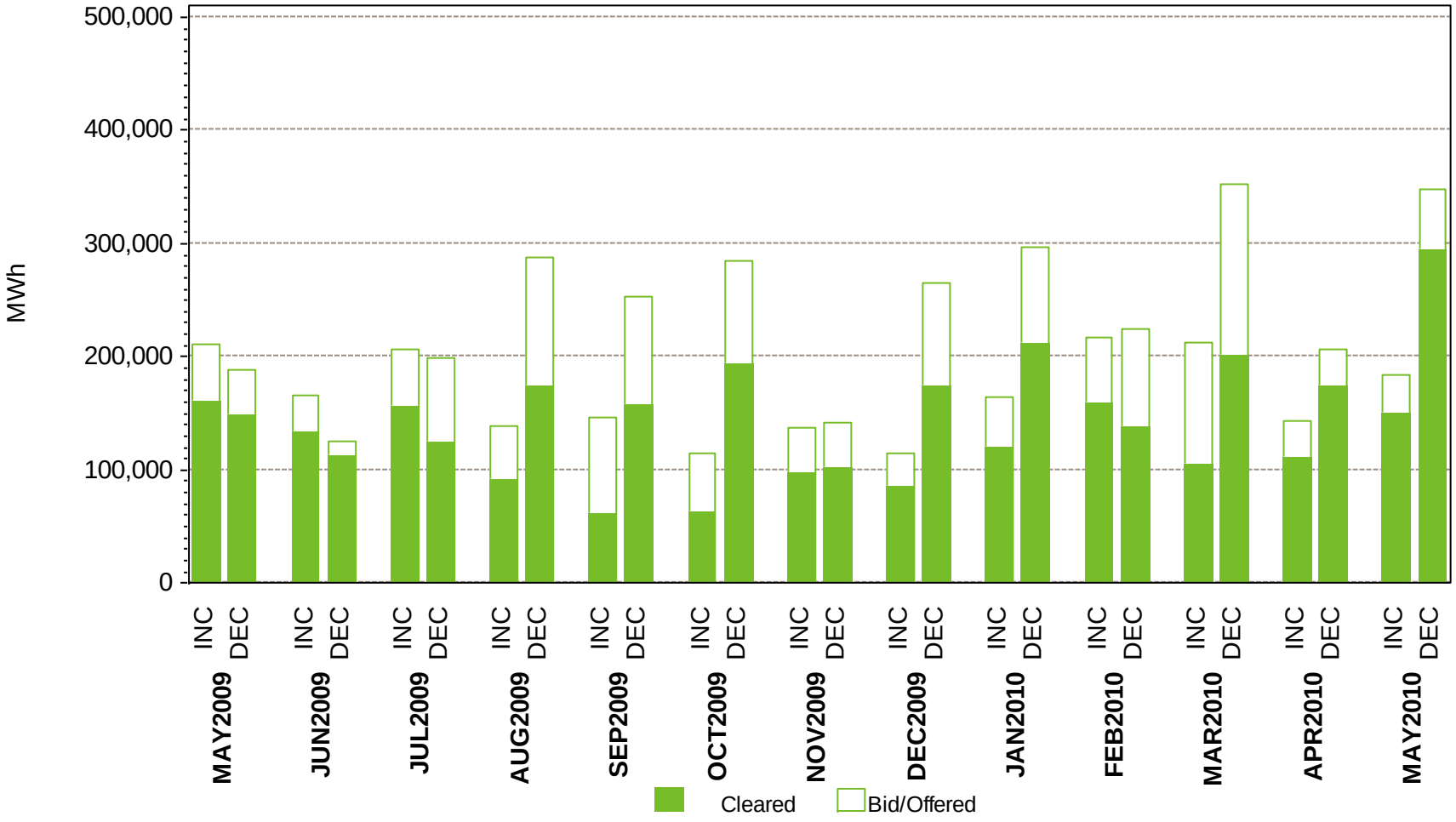


Zonal Decrement Bids and Cleared Amounts



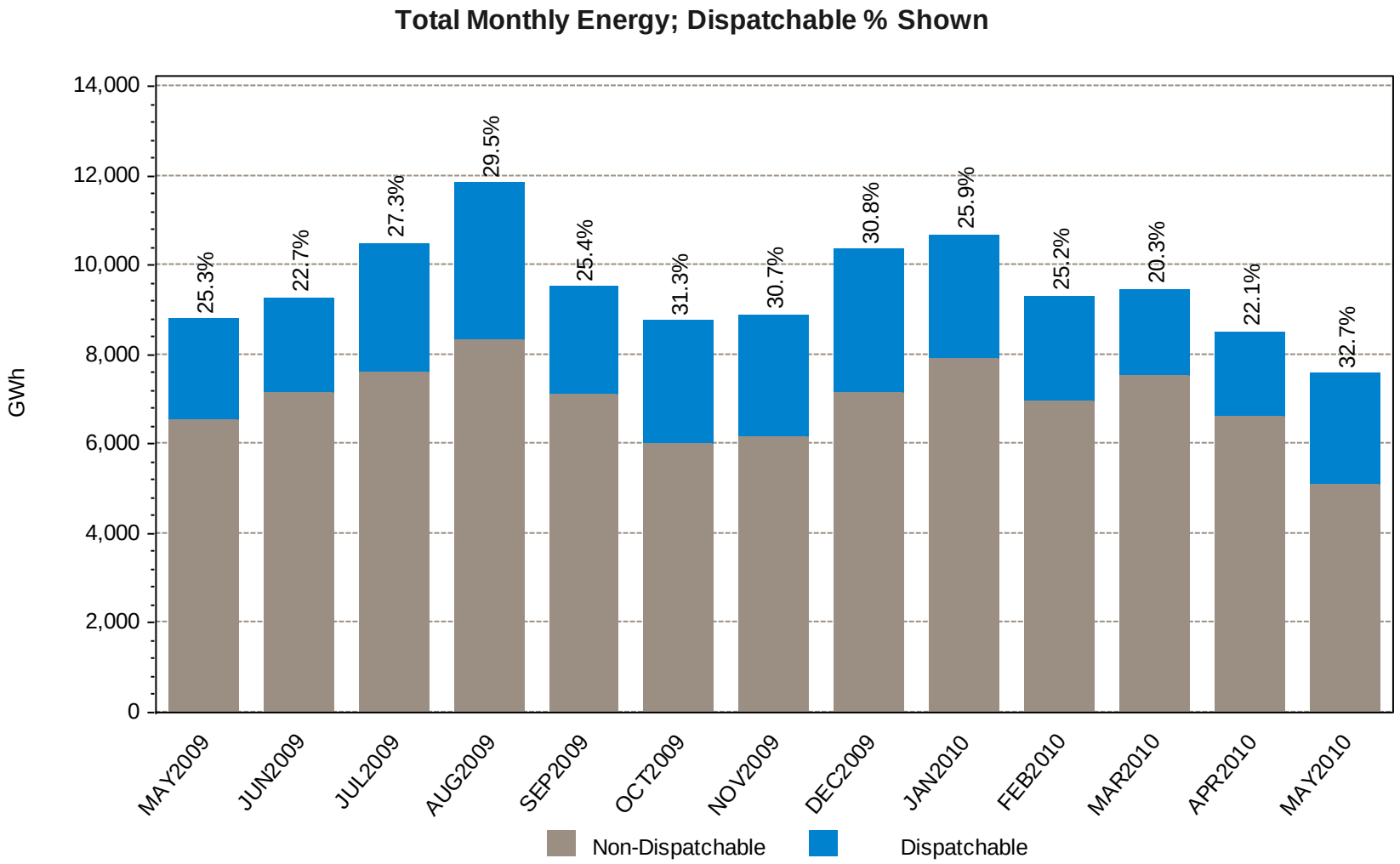
Total Increment Offers and Decrement Bids

Zonal Level, Last 13 Months

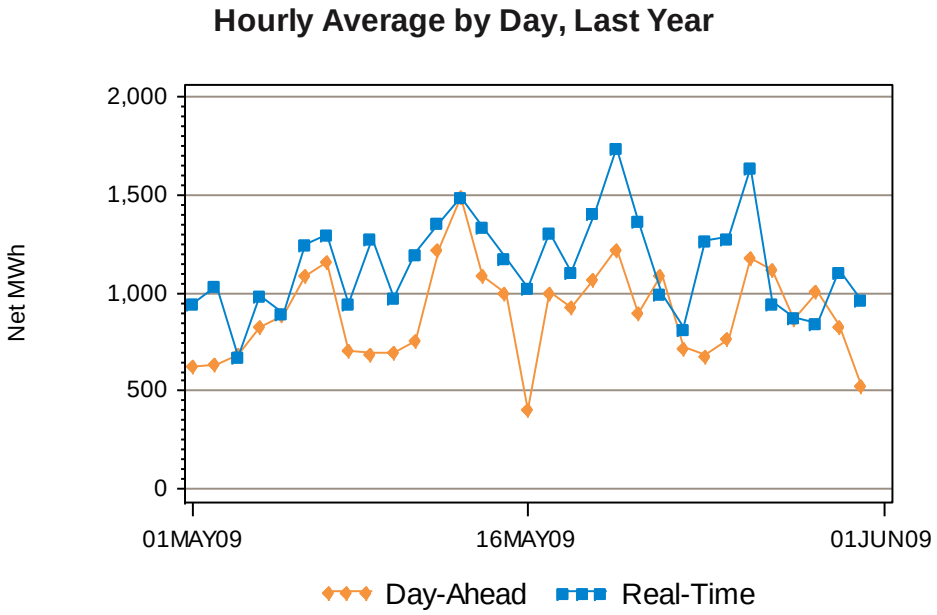


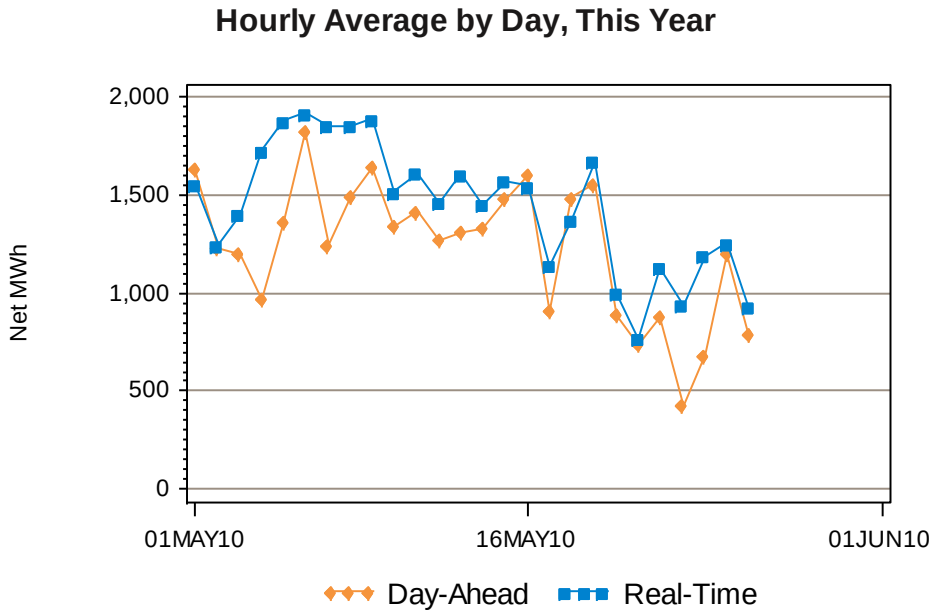
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

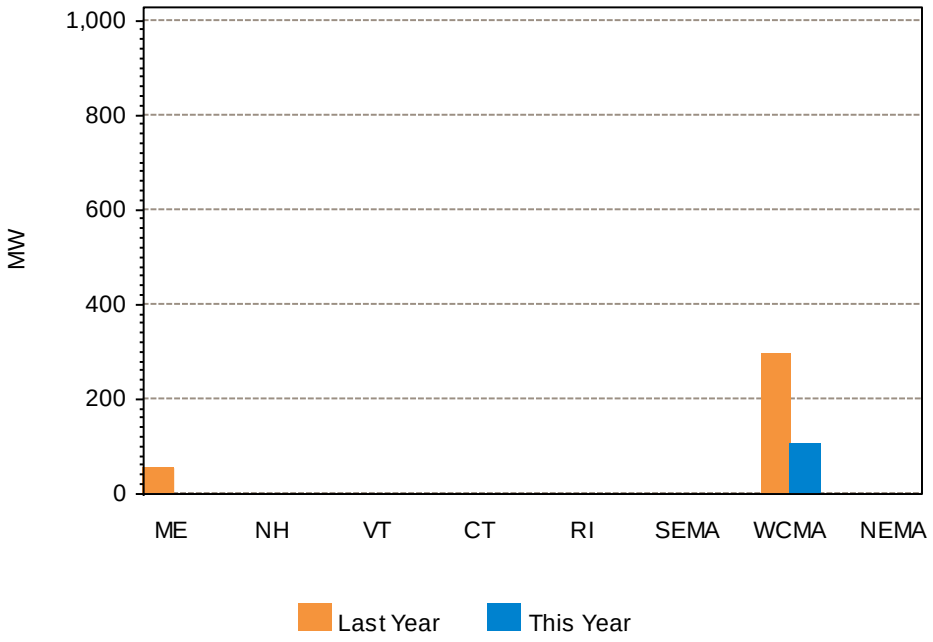




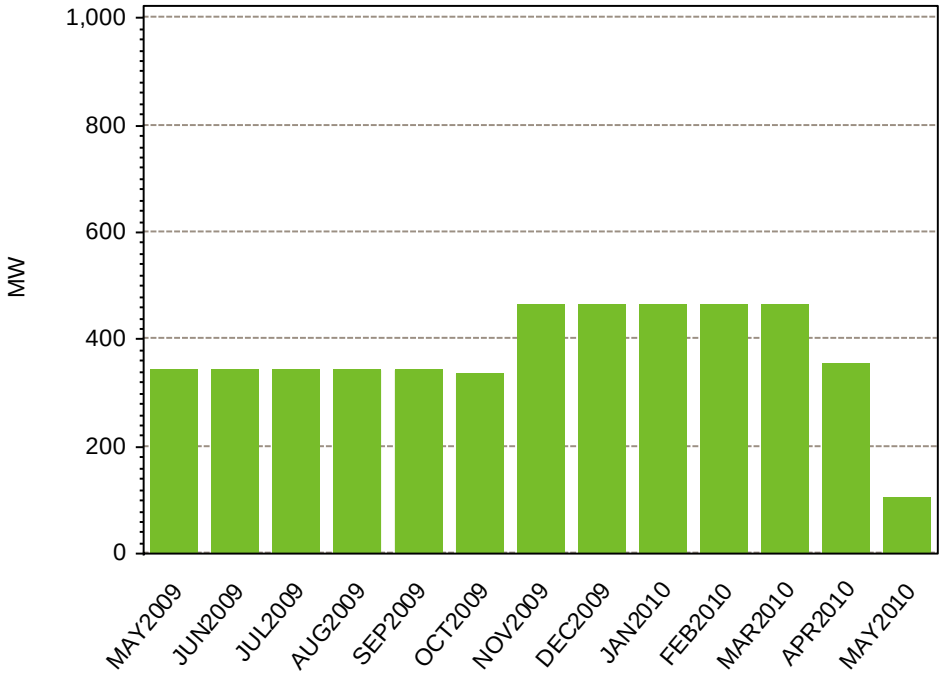
Net Interchange is the sum of daily imports minus the sum of daily exports
Positive values are net imports

Delisted Capacity, May 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

This section has been removed.

Reliability agreements expire effective June 1.

Regional System Plan (RSP)

Regional System Plan

- The May 25 Planning Advisory Committee (PAC) meeting was “Environmental Day” and included discussions of environmental regulations, environmental performance, state energy efficiency programs, the New England Wind Integration Study, and a draft scope of work for 2010 Economic Studies
- The June 16 PAC meeting will feature discussions of the 2010 Economic Study Scope of Work and Assumptions, the RSP Project List and Transmission Updates, and Load Pockets
- The New England East-West Solution (NEEWS) and the Vermont/New Hampshire Needs Assessment Scope of Work are scheduled for discussion at the July 15 or August 12 PAC meeting

Interregional Planning and Coordination

- The Northeast Coordinated System Plan 2009 (NCSP09) incorporated stakeholder comments and was finalized and posted at the following link
  - http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/2010/ncsp09final.pdf
- Environmental Advisory Group (EAG) teleconference scheduled for June 11

Department of Energy (DOE) 2009 Congestion Study

- Report is available at the following link
  - http://www.congestion09.anl.gov/documents/docs/Congestion_Study_2009.pdf
- The DOE has dropped New England from its list of "congestion areas of concern," citing the region's "multi-faceted approach" that has spurred investment in new supply-and demand-side resources, as well as planning and development of extensive transmission upgrades
  - Comments can be submitted to congestion09@anl.gov

Eastern Interconnection Planning Collaborative (EIPC)

- EIPC and DOE are still working to finalize agreement
- Eastern Interconnection model development wrapping up with analysis work to identify potential conflicts and opportunities to begin soon
- Stakeholder Steering Committee (SSC) structure established
  - 29 seat committee (3 representatives for each sector, 10 representatives for the states and 1 for the Eastern Canadian provincial rep)
  - Regional sector caucuses forming with SSC representatives elected by 27 seat caucus comprised of 3 sector reps from each of the 9 regions (addresses regional diversity concerns)
  - Alternative approach available for Non-Governmental Organizations (NGOs) and end user sectors
  - SSC meeting protocols established

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 6/1/10

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	4
Add parallel 115 kV cable in Mystic-Everett line	Oct-10	2
Add King Street - W. Amesbury 115 kV line	Mar-11	2
Sandy Pond 345 kV Breakers	Jun-12	2
Reconductor Overhead portion of Mystic-Everett 115 kV line	Jun-12	2
Replace Salem-Railyard Cables	Oct-13	2

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

Lower Southeastern Massachusetts (SEMA) Proposed Long-term Upgrades

Status as of 6/1/10

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

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

- ISO I.3.9 approval on 11/5/09
- Siting application scheduled to be filed late May 2010
- Full status update (needs, preferred solution, needs reassessment) given at 4/27/10 PAC
- Draft needs report posted 5/19/10

Maine Power Reliability Program (MPRP)

Status as of 6/1/10

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-Lincolnville)	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 6/1/10

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	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 6/1/10

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 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 filed supplemental testimony / studies on pros / cons of MMP versus MMP-V (separate the 395 3-terminal line into 2 separate lines)
      - Hearing on MMP versus MMP-V scheduled for June 2
    - Springfield – MA
      - Preliminary bench decision supports need but some routing/EMF issues remain

Transmission Siting Update, *cont.*

- Vermont Southern Loop Project
  - Project filed with Vermont Public Service Board in November 2007
  - Public Service Board approved on 2/11/09
- Maine Power Reliability Program
  - Project filed with the Maine Public Utility Commission on 7/1/08
  - Draft Examiner's Report was issued on 4/23/10 and responses were provided on 5/7/10
  - Maine PUC approved a settlement agreement, which includes most of the project, on 5/14/10. A formal order has not been issued yet.

Operable Capacity Analysis

Summer 2010 Operable Capacity Analysis (MW)

	June-10 [2] 50/50 Forecast (Reference Load)	June-10 [2] 90/10 Forecast (Extreme Load)
Generator Capacity Supply Obligation [1]	29,897	SAME
External Node Available capacity	331	SAME
Non Commercial Supply	0	SAME
Planned Outage MW [3]	100	SAME
Allowance for Unplanned Outages	2,800	SAME
Generation at Risk Due to Gas Supply	0	SAME
Net Capacity [4]	27,330	SAME
Peak Load Exposure (adjusted for Other Demand Resources)	26,618	28,738 (+2,120)
Reserve Requirement	1,800	SAME
Operable Capacity Required	28,418	30,538 (+2,120)
Operable Capacity Margin [4]	(1,090)	(3,210) (-2,120)

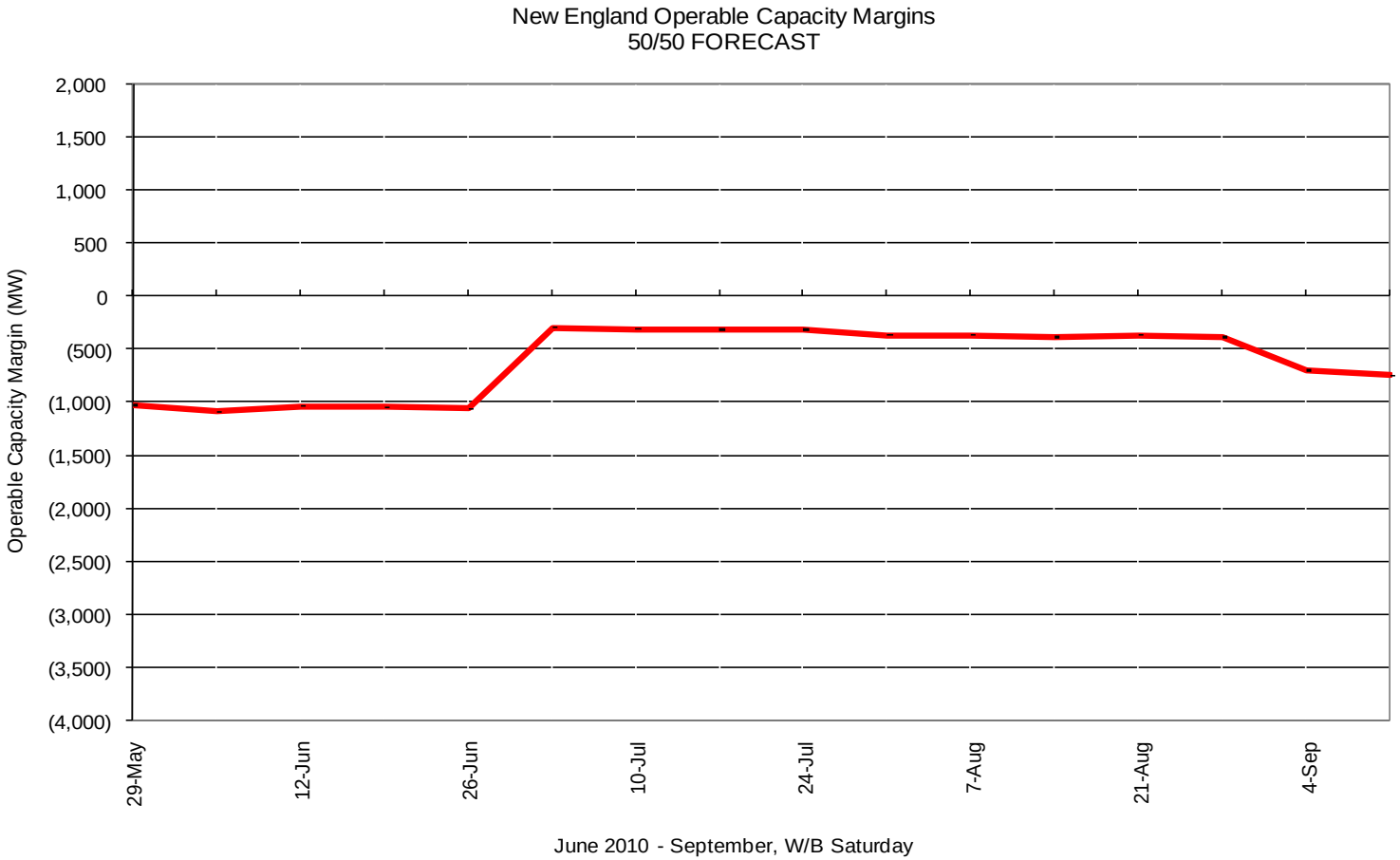
[1] Generator Capacity Supply Obligation is based on data as of June 2, 2010 and does not include Capacity Supply Obligations associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

[2] Based on week with lowest Operable Capacity Margin, week beginning June 5th.

[3] Rounded to the nearest hundred.

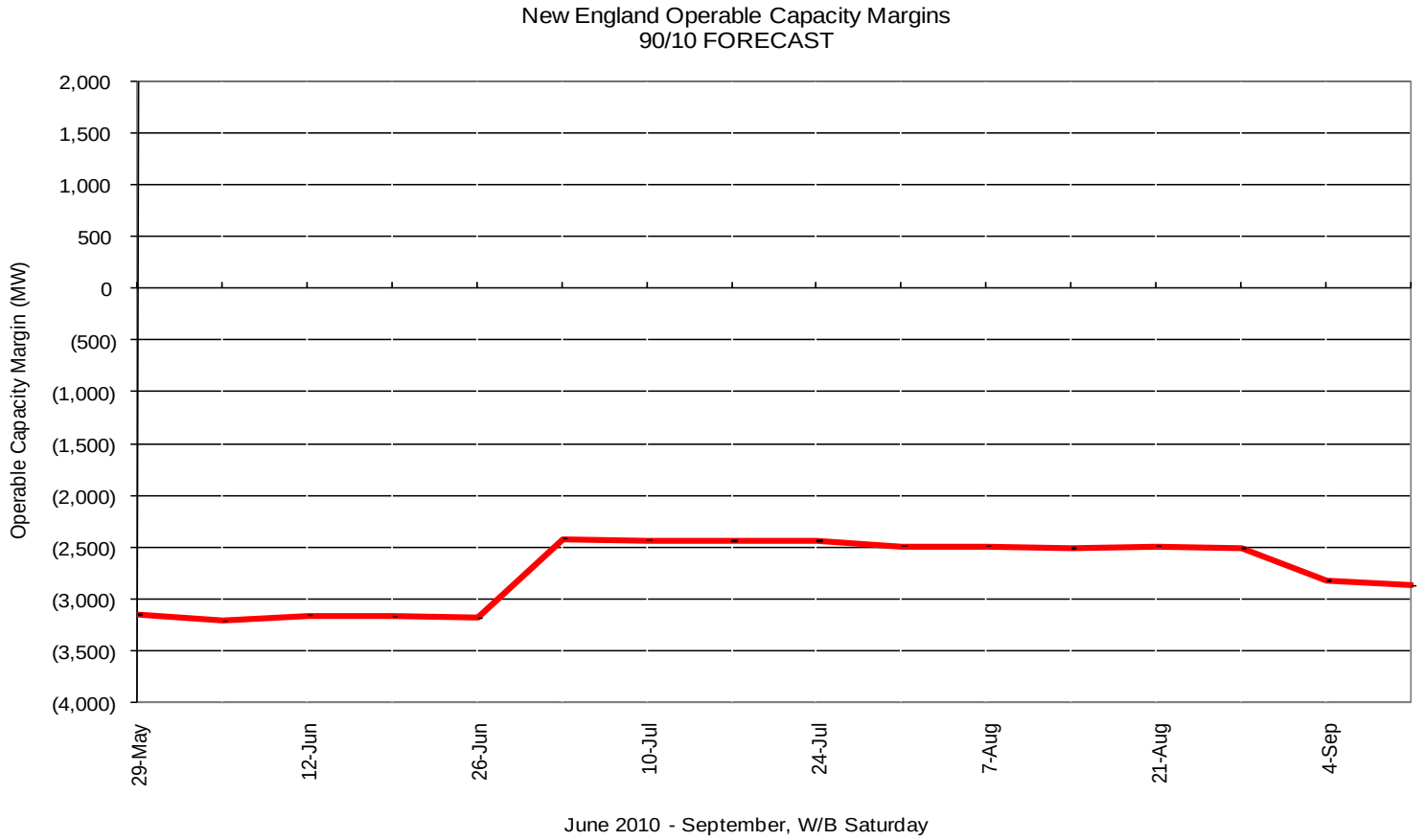
[4] Rounded to the nearest ten

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



Note: Based on data as of June 2, 2010. Does not include actions available in OP-4.

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



Note: Based on data as of June 2, 2010. Does not include actions available in OP-4.

Possible Relief Under OP4 based on OP4 Appendix A

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

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

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

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

NOTES:

1. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
2. The MW values are reviewed on a quarterly basis; actual available MW amounts can be viewed using the demand response dispatch software. Reserve Margin gross-ups not included and derate not applied.
3. The MW values are based on a 26,618 MW system load and the most recent voltage reduction test % achieved.

Appendix

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

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

June 2, 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.

	OPCAP SUPPLY							LOAD OBLIGATIONS			OPCAP MARGINS				
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL OPCAP MW	NON COMMERCIAL CAPACITY MW	PLANNED OUTAGES	UNPLANNED OUTAGES MW	GEN RISK DUE TO GAS SUP MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 2 MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN w/ OP4 actions through OP4 Step 6 MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
05/29/2010	29,897	331	0	0	2,800	0	27,390	26,618	1,800	28,418	(1,030)	520	(510)	640	130
06/05/2010	29,897	331	0	100	2,800	0	27,330	26,618	1,800	28,418	(1,090)	520	(570)	640	70
06/12/2010	29,897	331	0	0	2,800	0	27,380	26,618	1,800	28,418	(1,040)	520	(520)	640	120
06/19/2010	29,897	331	0	100	2,800	0	27,370	26,618	1,800	28,418	(1,050)	520	(530)	640	110
06/26/2010	29,897	331	0	100	2,800	0	27,360	26,618	1,800	28,418	(1,060)	520	(540)	640	100
07/03/2010	29,936	321	0	0	2,100	0	28,120	26,618	1,800	28,418	(300)	520	220	640	860
07/10/2010	29,936	321	0	0	2,100	0	28,110	26,618	1,800	28,418	(310)	520	210	640	850
07/17/2010	29,936	321	0	100	2,100	0	28,100	26,618	1,800	28,418	(320)	520	200	640	840
07/24/2010	29,936	321	0	100	2,100	0	28,100	26,618	1,800	28,418	(320)	520	200	640	840
07/31/2010	29,895	300	0	0	2,100	0	28,050	26,618	1,800	28,418	(370)	520	150	640	790
08/07/2010	29,895	300	0	0	2,100	0	28,050	26,618	1,800	28,418	(370)	520	150	640	790
08/14/2010	29,895	300	0	100	2,100	0	28,030	26,618	1,800	28,418	(390)	520	130	640	770
08/21/2010	29,895	300	0	0	2,100	0	28,050	26,618	1,800	28,418	(370)	520	150	640	790
08/28/2010	29,895	300	0	100	2,100	0	28,030	26,618	1,800	28,418	(390)	520	130	640	770
09/04/2010	29,895	300	0	400	2,100	0	27,720	26,618	1,800	28,418	(700)	520	(180)	640	460
09/11/2010	29,895	300	0	400	2,100	0	27,670	26,618	1,800	28,418	(750)	520	(230)	640	410

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO, during the Forward Capacity Market procurement period from June 2010 through May 2011. Does not include Settlement Only Generators.
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. New resources that have not yet acquired a CSO but will become commercial in the future.
4. Allowance for Planned Outages includes planned outages scheduled greater than or equal to 15 days in advance.
5. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance.
6. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions.
7. Total OpCap Supply Available per the formula (1 + 2 + 3 - 4 - 5 - 6 = 7)
8. Peak Load Exposure per data included in the 2010 CELT Report.
9. Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency.
10. Total Load Obligation per the formula (8 + 9 = 10)
11. Net OPCAP Supply minus Net Load Obligation (7 - 10 = 11)
12. OP 4 Action 2 Real-time Demand Response not including reserve margin gross-ups and derate applied.
13. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (11 - 12 = 13).
14. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes.
15. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (13 -14 = 15). This does not include Emergency Energy Transactions (EETs).

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

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

June 2, 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

	OPCAP SUPPLY							LOAD OBLIGATIONS			OPCAP MARGINS				
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL OPCAP MW	NON COMMERCIAL CAPACITY MW	PLANNED OUTAGES	UNPLANNED OUTAGES MW	GEN RISK DUE TO GAS SUP MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW	OPCAP FROM OP4 ACTIVE REAL-TIME DR MW	OPCAP MARGIN MW	OPCAP FROM OP4 REAL-TIME EMER. GEN MW	OPCAP MARGIN OP4
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
05/29/2010	29,897	331	0	0	2,800	0	27,390	28,738	1,800	30,538	(3,150)	520	(2,630)	640	(1,990)
06/05/2010	29,897	331	0	100	2,800	0	27,330	28,738	1,800	30,538	(3,210)	520	(2,690)	640	(2,050)
06/12/2010	29,897	331	0	0	2,800	0	27,380	28,738	1,800	30,538	(3,160)	520	(2,640)	640	(2,000)
06/19/2010	29,897	331	0	100	2,800	0	27,370	28,738	1,800	30,538	(3,170)	520	(2,650)	640	(2,010)
06/26/2010	29,897	331	0	100	2,800	0	27,360	28,738	1,800	30,538	(3,180)	520	(2,660)	640	(2,020)
07/03/2010	29,936	321	0	0	2,100	0	28,120	28,738	1,800	30,538	(2,420)	520	(1,900)	640	(1,260)
07/10/2010	29,936	321	0	0	2,100	0	28,110	28,738	1,800	30,538	(2,430)	520	(1,910)	640	(1,270)
07/17/2010	29,936	321	0	100	2,100	0	28,100	28,738	1,800	30,538	(2,440)	520	(1,920)	640	(1,280)
07/24/2010	29,936	321	0	100	2,100	0	28,100	28,738	1,800	30,538	(2,440)	520	(1,920)	640	(1,280)
07/31/2010	29,895	300	0	0	2,100	0	28,050	28,738	1,800	30,538	(2,490)	520	(1,970)	640	(1,330)
08/07/2010	29,895	300	0	0	2,100	0	28,050	28,738	1,800	30,538	(2,490)	520	(1,970)	640	(1,330)
08/14/2010	29,895	300	0	100	2,100	0	28,030	28,738	1,800	30,538	(2,510)	520	(1,990)	640	(1,350)
08/21/2010	29,895	300	0	0	2,100	0	28,050	28,738	1,800	30,538	(2,490)	520	(1,970)	640	(1,330)
08/28/2010	29,895	300	0	100	2,100	0	28,030	28,738	1,800	30,538	(2,510)	520	(1,990)	640	(1,350)
09/04/2010	29,895	300	0	400	2,100	0	27,720	28,738	1,800	30,538	(2,820)	520	(2,300)	640	(1,660)
09/11/2010	29,895	300	0	400	2,100	0	27,670	28,738	1,800	30,538	(2,870)	520	(2,350)	640	(1,710)

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO, during the Forward Capacity Market procurement period from June 2010 through May 2011. Does not include Settlement Only Generators.
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4. Allowance for Planned Outages includes planned outages scheduled greater than or equal to 15 days in advance.
5. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance.
6. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions.
7. Total OpCap Supply Available per the formula (1 + 2 + 3 - 4 - 5 - 6 = 7)
8. Peak Load Exposure per data included in the 2010 CELT Report.
9. Operating Reserve Requirement based on first largest contingency plus 1/2 the second largest contingency.
10. Total Load Obligation per the formula (8 + 9 = 10)
11. Net OPCAP Supply minus Net Load Obligation (7 - 10 = 11)
12. OP 4 Action 2 Real-time Demand Response not including reserve margin gross-ups and derate applied. Based on ARA3 results.
13. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (11 - 12 = 13).
14. OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes.
15. OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (13 -14 = 15). This does not include Emergency Energy Transactions (EETs).