Dr. Chadalavada reported that, over the previous month, ISO staff had reviewed details of the Power Systems in May, analyzed how dispatch of those conditions might differ after June 1 under the new Operating Procedure 4 (OP 4), and reviewed the Shortage Event triggering rules. He then provided a summary of the Power System conditions in May, noting that the weather forecast error due to unseasonably hot weather on several days impacted the load forecast, including on May 3 (17,501 MW), which was recorded as the second highest peak ever for that week; and May 26 (22,837 MW), which was recorded as the highest peak ever for May. He noted that, during these peak times there was a significant amount of generation and transmission out-of-service for maintenance, including approximately 12,000 MW of generation. He noted, in particular, that a noticeable amount of generation located west of the east-west interface normally available for dispatch was out-of-service and the limited flexibility in Real-Time to commit units because of their start-up lead times. He also explained that transmission system improvements, which minimized the need for supplemental commitments, resulted in limited surplus generation committed Day-Ahead.

Dr. Chadalavada then reviewed several events in May with respect to M/LCC2, OP 4, and Reserve Constraint Penalty Factor (RCPF) activations for Thirty-Minute Operating Reserves (TMOR) including: May 2 - M/LCC2, RCPF activation and OP4; May 3 - M/LCC2, RCPF activation; May 8 - M/LCC2, RCPF activation; and May 26 - M/LCC2, RCPF activation and OP 4. Based on analysis of the events in May, he explained, effective June 1, and consistent with the Market Rules, the ISO tied the declaration of Shortage Events to the RCPF activation for total TMORTen Minute Operating Reserves (of 30 or more contiguous minutes). He noted that the implementation was based on NPCC criteria which allowed each Control Area four hours to

recover its TMOR, and that the current Market Rules specified a RCPF value of $100 for total TMOR and $840850 for total Ten- Minute Operating Reserves. He then explained that, in light of recent transmission improvements, which had significantly reduced surplus commitment, it was reasonable to expect an increase in M/LCC 2 and OP 4 procedures. He said that even small deviations in load forecast, tie schedules and generation/transmission outages could cause a more frequent depletion of TMOR for short periods of time.

Concluding his summary of the May system events, Dr. Chadalavada provided a high-level glimpse of how the events might have unfolded had they occurred with full implementation of FCM. He noted that, under the revised OP 4, Actions 1 and 2 would have been implemented system-wide to maintain TMOR. Real-Time exports above the Day-Ahead schedule, he explained, would have been curtailed prior to declaration of OP 4, and approximately 275 to 375 MW of Real-Time Demand Resources likely would have been required. With such implementation, Shortage Events would not have been declared.

In response to members' questions, Dr. Chadalavada reviewed how Shortage Events are determined, noting that the Market Rules focused on RCPF activation and did not otherwise provide specific triggers, and adding that the May events illustrated why tying RCPF to TMOR reserves would not be appropriate. He acknowledged the dependency of load forecasts on weather forecasts. Mr. Peter Brandien clarified that much of the uplift was driven by 345 kV line outages, as well as out-of-service generation in western New England, and while the hot weather and the forecast just made it more difficult to operate the system, the uplift would have been there even without the load forecast error. Dr. Chadalavada also explained the treatment and impact of capacity imports during the May events. Looking ahead to June, Dr. Chadalavada noted his

ISO new england

memo

To: NEPOOL Participants Committee Meeting Attendees

From: Gordon van Welie

Date: August 4, 2010

Subject: CEO Report: ISO New England's 2011 Budget

Attached please find a presentation regarding the two budget scenarios we initially discussed with you at the NEPOOL Summer Meeting. This presentation includes additional details regarding the various components of each scenario. For your reference, we have also included the materials presented at the Summer Meeting.

As we discussed at the Summer Meeting, we have proposed two alternatives for the 2011 budget. The first is a baseline approach that reflects the resources required to maintain the status quo (including fulfillment of past commitments). The second alternative is a "measured growth" approach to 2011, which allows us to deliver additional services on top of the baseline.

I would like to discuss the attached presentation at Friday's meeting during my CEO Report. I look forward to receiving your feedback.

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ISO new england

memo

To: Attendees at New England Power Pool Annual Summer Meeting

From: Gordon van Welie

Date: June 16, 2010

Subject: ISO New England's Future Structure and Budget

The purpose of this memo is to share our initial thoughts on our future structure, which, in turn, will influence our future budgets. Our objective is to discuss and reach consensus with you on structure, following which we will propose an appropriate budget for 2011.

This discussion follows internal consideration of a request from our Board of Directors that we think about our structure in the context of an increased demand for our services for the next several years. In formulating our response, we have attempted to meet the following organizational design objectives, some of which are naturally conflicting:

- Ensure that we have adequate resources so that we can be responsive to the growing demand for our services and not "fall behind the curve"
- Ensure that our services are delivered in a high quality fashion
- Ensure cost effectiveness and efficiency in the delivery of our services
- Keep our overall costs as low as practicable, so as not to place an unnecessary burden on the region

We have developed two possible scenarios for our future structure. The first scenario is maintenance of the status quo, in which case ISO-NE would remain at approximately its present size and budget level, with normal inflationary increases and increases to fulfill existing commitments. The second scenario involves measured growth to support emerging policy initiatives.

Each of these scenarios is discussed in more detail below, following background information on ISO-NE's growth to date and the challenges in the current environment.

I. Background – Growth of ISO-NE to Date

ISO New England was established in 1997 with approximately 150 employees. Since that time, we have experienced significant growth as we have added services in fulfillment of our twin missions – ensuring bulk power system reliability and efficient wholesale electricity markets.

The formation of the ISO and the introduction of the interim markets in May 1999 were the first significant changes to the system operator function since it was implemented in the early 1970s. The introduction of Standard Market Design in 2003 caused another step-change in the services we provide and this was accompanied by a substantial increase in our operating costs.

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More recently, the organization has been faced with an increased demand for services. This demand results from a number of factors, including the region's investment of over $4 billion in transmission improvements to date, with another $4 - 5 billion in planning or under construction. These transmission improvements, paired with the qualification and interconnection of almost 17,000 MW of new supply and demand resources, have caused a significant increase in workload throughout the organization.

In addition, changes in the markets have required a commitment of our resources. After the implementation of Standard Market Design, we implemented changes to our regulation market, introduced locational forward reserve and real-time co-optimized reserves markets, implemented what is arguably the most complex and sophisticated forward capacity market in the nation, and made a significant investment in the infrastructure necessary to fully integrate Demand Resources into our markets and operational infrastructure.

We have seen the establishment of NERC as the overseer of mandatory reliability standards, the North American Energy Standards Board Wholesale Electricity Quadrant as the forum for wholesale electricity business standards, the National Institute of Standards and Technology as the overseer of smart grid standards, and a host of federal and state policy initiatives aimed at moving the bulk power system towards renewable energy, including the establishment of the Eastern Interconnection Planning Collaborative. We have participated substantively in all these forums.

Demand for our services has also increased as the number of market participants, state officials and other persons interested in our markets or the bulk power system has increased. The number of participants in our markets has grown from less than 100 to more than 400, not counting the dozens of state organizations that have an interest in the outcomes in the markets and the regional system planning process. Our stakeholders are more educated, and seek integrated information on the markets and bulk power system to help them make informed decisions. We are also seeing a growing interest in our work from end-use consumers who are seeking a greater understanding of the regional power system so they can participate more effectively in the stakeholder process.

Not surprisingly, these evolving requirements and activities have caused our costs and employee headcount to rise. As of 2010, our operating budget is around $109 million, our capital budget (excluding the smart grid project that will be reimbursed by the DOE) around $25 million, and we have 496 employees. However, because we have historically limited the capital budget to around $22 - $25 million and have only added resources once it was clear that the workload was going to be sustained, we have been able to control the rate of growth of the organization and balance it with the need to ensure operational excellence.

II. Background – Current Challenges and Workload Drivers

We have identified several challenges for the future that will affect the workload at the ISO. Each is outlined below, along with our responses to date.

A. Responding to Government Policy on the Environment and Energy Independence

The trend is clearly towards changing the resource mix on the bulk power system from fossil fuel-fired resources to carbon-free or low carbon resources. The broad policy momentum is enormous, as the policies driving this change are targeting climate change, general environmental

concerns, economic development and energy independence. The only question appears to be the pace of the transformation, which will depend on the consumer's willingness and ability to pay. High fossil fuel prices, a high price on carbon, or high renewable energy targets will tend to accelerate our movement in this direction, and the converse is also true.

Aside from the direct investment in low carbon resources, it is likely that this policy initiative will also require a significant additional investment in transmission infrastructure. All of this will place significant demands on the ISO. We have taken the first steps towards preparing for this, including commissioning a wind integration study, conducting analysis to support the New England Governors' Renewable Blueprint and establishing a small team to engage in the Eastern Interconnection Planning Collaborative.

B. Implementation of Smart Grid

Smart grid encompasses everything from the deployment of smart meters connected to smart appliances at the retail level to the electrification of the transport sector (plug-in electric vehicles) to applications at the grid operator level such as demand resource integration and phasor measurement deployment. It will enable the integration of renewable and other intermittent/alternative resources and, in some cases (e.g., plug-in electric vehicles), allow for benefits beyond the grid.

The implementation of the smart grid, together with the challenge of integrating large amounts of wind and demand resources, will significantly increase the complexity of managing the bulk power system. Increased complexity generally results in increased operational risk, and the ISO will need to manage risk through increased automation and ever more sophisticated compliance and risk management tools. The speed of implementation of the smart grid is uncertain. We have already committed to the DOE Synchrophasor Project, development of smart grid standards and pilot projects dealing with alternate technologies. We currently have a small group of expert resources to respond to emerging initiatives in this area.

C. Significantly Increased Demand for Information Services

One constant over the past decade has been increasing demand for data and information from the ISO. In recent years, as our systems and designs have become more complex and our stakeholders have become more educated and sophisticated in their requests, we have seen a significant increase in requests for more holistic analyses and detailed reports. In addition, we recently agreed to perform impact analysis on all major initiatives, and we have extensive formal reporting obligations in our tariff and as a result of orders from the FERC. All of these requests cut across all our operations.

We have three concerns in this area. The first regards the sustainability of our approach to date, which is to have the relevant department devise solutions to these various requests as they emerge. We are also concerned about our web infrastructure. We invested in a significant upgrade in 2006 and, since then, web traffic has grown by over 700%, requiring us to consider further upgrades in infrastructure. Third, we are being pushed to make changes to our infrastructure due to technology obsolescence – e.g., Oracle is discontinuing its Discoverer product, which is the tool used by some 300 users in the organization to produce reports. To address these concerns, we have launched an internal information delivery operational excellence

project to define the scope of the problem and the range of solutions.

D. Significantly Increased Compliance and Audit Obligations

FERC has raised the bar with respect to compliance obligations and audits, particularly in the areas of reliability and cyber-security standards. NERC plans to completely revamp its suite of standards in these two areas. In addition, KPMG has informed us that, from October 2010 onwards, the SAS 70 audit scope will include the Software Development Life Cycle, and the award of DOE grant money has created substantial reporting and compliance obligations for a five-year period and requires that we undergo a governmental audit. It is also likely that we will see some obligations arise from the discussions between FERC and the CFTC regarding wholesale electricity market futures derivatives trading. While we have established a robust compliance program and structured the organization in a manner that provides for a well-coordinated response, we will likely need to make incremental investments in people and technology to maintain our responsiveness.

E. Implementation of the Wholesale Markets Project Plan

Wholesale market design and implementation has been one of the major workload drivers for the ISO over the past decade. Although we now have a full suite of markets and services in place, we believe that we will see sustained demand for enhancements to our markets from our market monitors and participants and as a result of our own operational experience. Additionally, we expect that the policy drive toward changing the resource mix will create additional complexities and problems that need solutions.

In anticipation, we are augmenting the wholesale market design team by adding a senior economist position and using expert consultants for selected activities. However, a significant increase in our ability to process market design changes would require an expansion across the organization that would significantly drive up both operating and capital costs – and would require more resource commitment from NEPOOL and NECPUC as well. Therefore, we believe that this area can sustain only incremental increases to our throughput.

F. Supporting the Transmission Projects Identified in the RSP and Responding to Emerging Planning Issues

The ISO has been actively involved in the process of upgrading the transmission system to meet NERC and NPCC reliability criteria. More work remains, and, in addition, the ISO must address the other issues created by the changing nature of the power system. For example, almost 8,000 MW of oil-fired resources that are 40 years or older produced less than 2% of energy last year. This fact, coupled with the environmental and other market pressures faced by these resources, means that many of these resources are likely to retire in the next decade. This has significant implications for the planning, operations and market design functions at the ISO.

G. Aging Workforce

We are anticipating retirements of key resources in upcoming years, and are concerned about the competition for employees in the areas of Operations and Planning and in some specific areas in IT. As a result, we have established summer internship programs and have also, where possible, hired new

graduates into open positions. Last year, we specifically approved two additional positions for System Operations so as to improve our ability to respond to the turnover that occurs in the Control Room. In addition, we have an active succession planning process to ensure that we are growing the talent that we need and that we can manage through the many retirements we will face in the next decade.

III. Structure and Budget Scenarios

While we cannot precisely predict the organizational demands caused by the challenges outlined above, we must have a viable plan for responding to our external environment in a way that maintains our organizational objectives. This leads us to propose the two scenarios below for discussion. In each case, we have provided estimates of the related budget. However, these estimates are preliminary and likely to change as we review and discuss them internally and with you.

A. Scenario One: Maintain Status Quo

The first scenario is fundamentally reactive and takes a "wait and see" approach to the development of the challenges outlined in this memo. In this scenario, the ISO budget will only contain normal inflationary increases and increases due to existing commitments, and we will manage throughput to match our resource constraints. The primary risk in Scenario One is that the emerging policy and stakeholder demands may quickly outstrip our capabilities and our responsiveness will suffer.

Specifically, in this scenario, we will take the following actions in response to the challenges discussed:

1. Develop a framework with our stakeholders for conducting impact analyses and, during the next six months, quantify additional resources and infrastructure needed to support this commitment.

2. Analyze the implications of the final FERC ruling on FCM enhancements related to Alternate Price Rule and Zonal Modeling and determine whether the organization will require additional resources.

3. Fund the information delivery operational excellence project discussed above to quantify the scope of the delivery of content and information to the diverse groups of stakeholders and the range of possible solutions.

4. Make some incremental changes to our organizational structure to achieve a sharper focus on some of the emerging policy matters, and provide job growth opportunities for high-potential employees identified through our succession planning process.

Attachment 1 shows the components of a high-level budget for this scenario, as compared to the 2010 operating budget. The budget may, roughly, increase from 2010 levels by 5.7%, primarily to fund inflationary increases in salaries, computer services, NPCC dues, and interest expense, and to reinstate some deferred training and meeting expenses.

Because we are not able to quantify the budget implications of all FERC proceedings, impact analysis, FCM, and the information delivery operational excellence project, we would, to the extent necessary, either absorb the additional activities arising from these three items in 2011 by displacing lower priority activities, or defer the additional activities until they can be incorporated in the 2012 budget.

B. Scenario Two: Measured Growth

The second scenario is fundamentally proactive and involves measured growth in key areas of the organization in anticipation of an increased demand for our services as described in Section II herein. It does not involve significant increases to the size of the organization, as our physical infrastructure (building and IT) is limited and we are presently close to full capacity. Rather, the second scenario involves a continuation of the organization's growth over the last ten years, which has involved the incremental addition of resources and infrastructure in areas where we have the greatest need and vulnerability.

This scenario also responds to the stakeholder suggestion that we actively plan for unallocated resource time to deal with emerging issues by increasing contingency funds for emerging work. Since its inception, ISO-NE has maintained a contingency in the annual budget of $700,000 to cover emerging work. In this second scenario, this contingency would be increased. This approach gives the ISO greater flexibility to respond to changing circumstances.

If we move forward under this scenario, we anticipate that we would prepare a more detailed two-year plan that quantifies and phases-in incremental additions to our resources and infrastructure to prepare for emerging work. In 2012, we would again evaluate the direction and pace of the key policy initiatives and, if necessary, make appropriate adjustments to our resources and infrastructure.

Accordingly, in addition to the actions in the first scenario, the following items will be addressed in the second scenario:

1. Increase the size of the Emerging Work contingency by $1 million (from $700,000 to $1.7 million) and ensure that at least $2 million of the capital budget is unallocated at the start of the year. These unallocated funds would be allocated in conjunction with stakeholders at the beginning of the year, with reconsideration at mid-year. This process would build on the quarterly reviews of our work plan with NEPOOL and NECPUC.

2. Increase the employee resource base by approximately 24 people over two years, consistent with the workload drivers described in Section II herein. The primary purpose of these additions would be to increase our bench strength, primarily in the key areas of operations, market development, system planning, information technology and compliance.

3. Increase the size of our Summer intern program by approximately 30% (from approximately 17 in 2010 to 22 in 2011). This is a cost-effective way of identifying desirable future employees and we would aim to allocate up to one-third of the new positions identified to recent graduates. These are temporary positions and are not included in the additional headcount described above.

4. Increase our professional fees budget by a total of $2 million over two years in the key areas of operations, system planning, information technology, training, market monitoring and compliance.

In this scenario, we would be adding approximately $6 million in operating costs over two years. This would represent a further 5.2% increase over the Scenario One budget, when adjusted for

inflation, over the two-year period. Attachment 2 provides a graphical description of the increase from Scenario One to Scenario Two.

There are two risks with this scenario. The first is that we may overshoot the real demand for our services and be left with an organization that is too large for the services it performs. The second risk is that the quality of our services may be impacted if we commit to additional work or add resources too quickly. However, adding the resources over a two-year budget period mitigates these risks, as we can always modify or eliminate planned additions. Were we to overshoot, it would be relatively straightforward to reduce operating costs through reduced professional fees and natural headcount attrition. In addition, this approach allows the organization to recruit and absorb new resources at a measured pace, with the goal of maintaining high levels of service quality.

IV. Conclusion

Again, it is my hope that this memorandum will spark a discussion about stakeholders' needs and the appropriate model for the ISO going forward. I look forward to our meeting next week and to discussing the ISO's future with you.

ISO New England
Draft 2011 Operating Budget

Meeting with NEPOOL Officers and NECPUC Representatives
August 5, 2010

ISO new england

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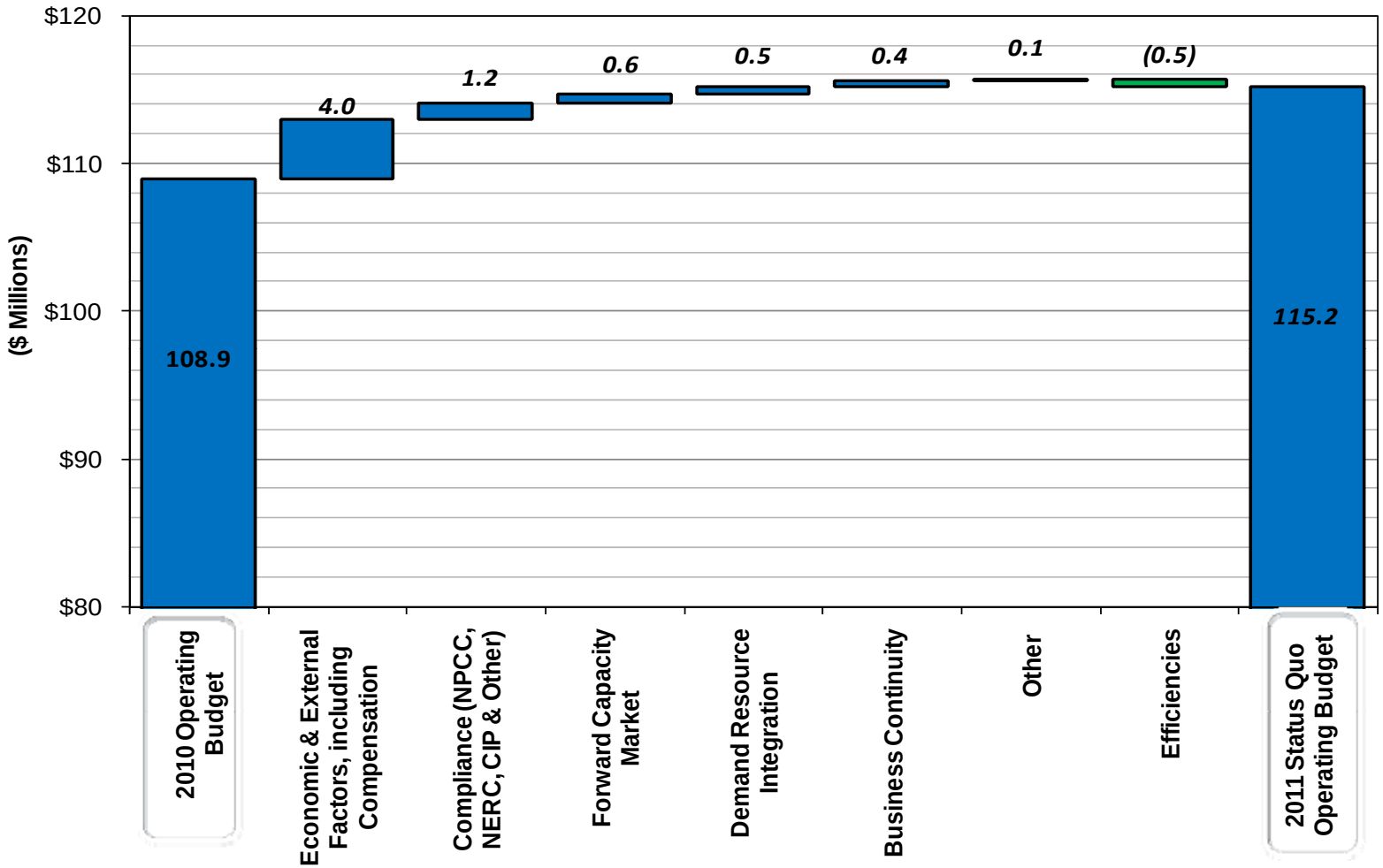
2011 Status Quo Operating Budget



2011 Status Quo Operating Budget

- Economic & External Factors, including Compensation

Description	Dollars in Thousands
Salaries: Merit and Promotion – estimated at 4%	$2.8
Interest Income/Expense (Net) – Due to decreased interest rates	$0.5
Employee Benefits - including Health Insurance increases above inflation and slightly reduced Pension expense	$0.7
Total	**$4.0**

- Note: Salary increases are an estimate at present, based on an initial survey at this time. Consistent with past practice, the ISO will base its final budget proposal on five industry surveys that will be available in the September timeframe. We will also revalidate the estimates in January 2011.

2011 Status Quo Operating Budget

- Compliance increases are due to (i) increased NPCC dues of $300,000 and (ii) $925,000 related to an additional seven positions. The increased positions are needed in the Operations, Finance and Cyber Security areas to meet the increased NERC and CIP standards, the Department of Energy and other compliance requirements as defined in the ISO Tariff.

- Forward Capacity Market increases will cover license costs of Power Auctions (the FCA Auction Vendor) for FCA #5 and one additional position in the Information Technology area to support the FCM settlement software applications.

- Demand Resource Integration support and auditing costs have created the need for three additional positions in the Market Services and Information Technology area to support this function.

2011 Status Quo Operating Budget

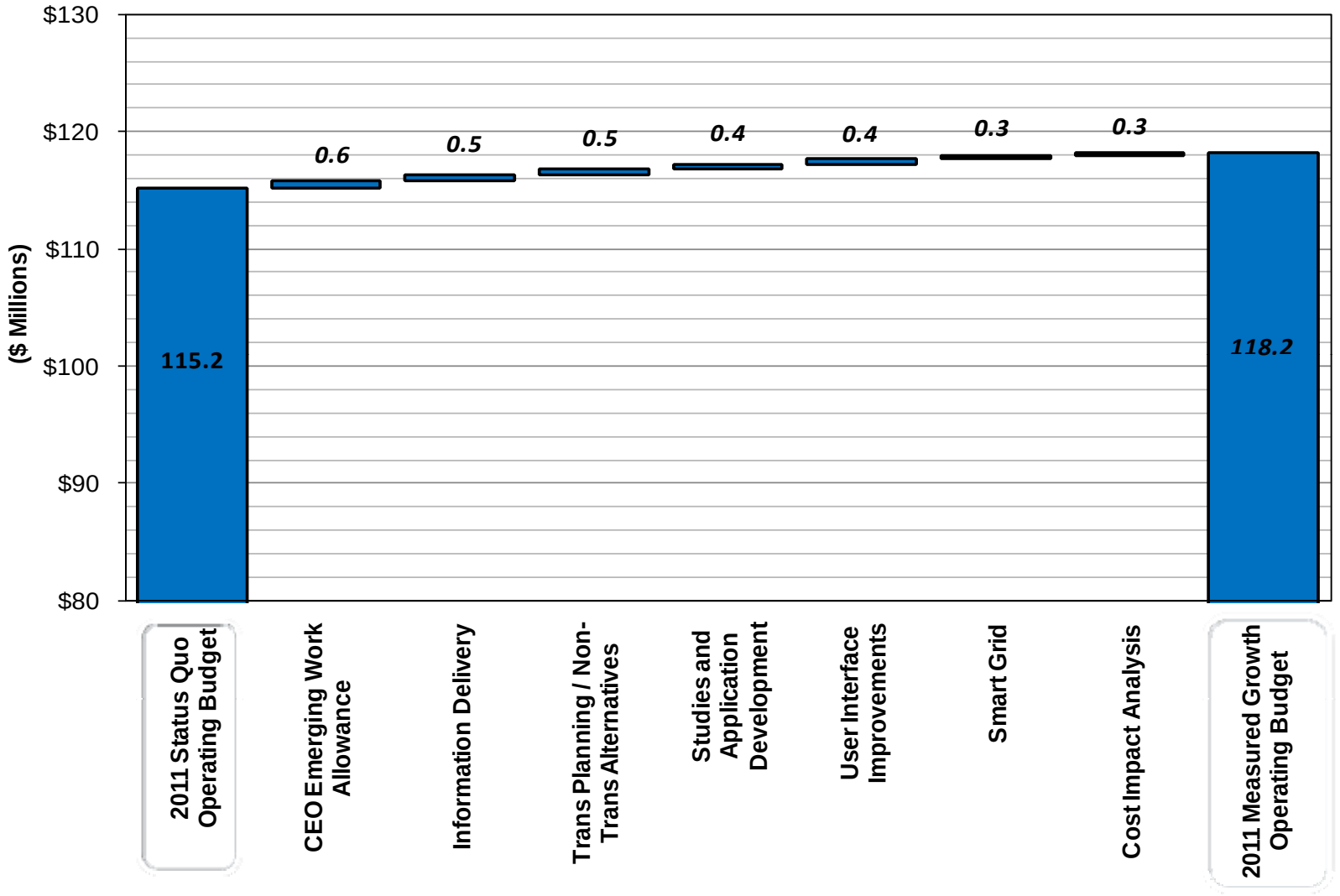
- Our business continuity project includes enhancements to the Backup Control Center (BCC) and additional frame relay communications circuits. This results in additional hardware maintenance and license and communications services costs.

- "Other" includes: 3 additional positions in the areas of Training, Auditing, and Project Management for $330,000; an increase in Meetings Travel and Seminars to restore some of the training that was cut from the 2010 budget ($330,000); a partial offset in the amount of a $311,000 decrease in professional fees due to one-time work not being needed (i.e., the wind study); various increases in computer services costs of $250,000; a decrease in salary expense of $1.4 million due to increasing the vacancy rate from 2% in 2010 to 4% in 2011; various adjustments to building services; reduced internal capital labor; rents and lease, payroll accruals, etc., which comprise the balance of the change.

2011 Status Quo Operating Budget

- Efficiencies: We were able to achieve $500,000 in savings in the area of computer services as a result of the Demand Resources Integration project. We eliminated the need for eLutions licenses (the vendor that supported the previous communication platform with demand resources). In addition, the development of a virtual office environment has reduced licensing costs for application support/web logic and database.

2011 Measured Growth Operating Budget



2011 Measured Growth Operating Budget

- The CEO Emerging Work Allowance increase will be used to meet emerging issues such as new FERC NOPRs or orders, new requests from regulators and/or market participants, and increased compliance requirements, including an additional position in our Compliance Department to meet the growing workload.

2011 Measured Growth Operating Budget

- Information Delivery
  - One constant over the past decade has been the significant increase in demand for data and information from the ISO. In response, ISO-NE has launched a project with the objective of assessing the current state of our information production and delivery processes and infrastructure. The initial deliverable will be a road map and project plan for improving our information delivery processes and technology infrastructure. The road map/project plan will describe a series of activities/projects to improve both our external and internal information delivery services.
  - 2011 costs for this activity include $150,000 in professional fees and 3 additional positions. Capital costs for upgrades to technology infrastructure will be included in the 2011 budget and beyond.

2011 Measured Growth Operating Budget

- Transmission Planning/Non Transmission Alternatives
  - New England stakeholders have requested that the ISO provide additional information on the role of non-transmission alternatives in meeting regional reliability needs, as identified in the regional planning process. ISO is evaluating the analytical tools and methods available to develop and present this information to stakeholders and market participants. Initial findings on this will begin to be reported through the PAC process and in RSP11. This will be an area of increased focus and expanding/refining our efforts in this area will require increased staff attention and support.
  - Furthermore, the requests for economic studies continue to grow.
  - Costs for these activities include $250,000 in professional fees and 2 additional positions.

2011 Measured Growth Operating Budget

- Studies and Application Development
  - The ISO will continue to work with stakeholders on the recommendations from the Wind Integration Study and plans to continue to evaluate new applications that provide for increased optimization of the power system. Examples include Adaptive Line Ratings, Robust Optimization for system planning, and provision of a 1-2 hour look-ahead capability to the control room that will allow for improved commitment and dispatch in real-time.
  - 2011 costs for this activity include $150,000 in professional fees and 2 additional positions.

2011 Measured Growth Operating Budget

- User Interface Improvements
  - As the complexity of the market design has increased, so has the interrelationship of data elements across the various customer user interfaces. The ISO intends to launch a project to initially improve the User Interface technology (for example, eMarket, eFTR, LFRM, etc.) and then provide enhanced error-checking functionality that makes it easier for Participants to transact in the various ISO markets.
  - 2011 Operating Costs for this activity include $100,000 and 2 additional positions. It is likely this will also require fairly significant capital expenditures over a period of several years.

2011 Measured Growth Operating Budget

- Smart Grid
  - Several organizations (NIST, NAESB, OASIS) have been accelerating the development of Smart Grid standards related to the power grid. These standards, if they are made mandatory, will impact New England. The ISO would like to participate actively in this process to ensure that New England's perspective is provided.
  - The ISO would also like to continue its research effort into the development of an advanced grid simulator to model the operational impacts of new technologies.
  - 2011 costs for this activity include $200,000 in professional fees and 1 additional position.

2011 Measured Growth Operating Budget

- Cost/Impact Analysis
  - To assist stakeholders in evaluating any major ISO initiative that affects market design, system planning or operation of the New England bulk power system, the ISO has committed to providing quantitative and qualitative information on the need for, and the impacts, including costs, of the initiative. While the ISO currently provides certain quantitative and qualitative information on an *ad hoc* basis, it is already thinking about how to conduct these studies in a more systematic and consistent way. The ISO has sought the assistance of a consultant (the Brattle Group) to assist it in developing a general analytic framework for these required analyses and to design and implement analytic tools that may be required.
  - 2011 costs for this activity include $150,000 in professional fees and 1 additional position.

Appendix: New England Power Pool Summer Meeting Budget Discussion Materials

NEPOOL Participants Committee Report August 2010

Vamsi Chadalavada
Senior Vice President and Chief Operating Officer

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Highlights

- **Day-Ahead (DA), Real-Time (RT) Prices and Transactions**
  - July natural gas prices over the period were 2.3% lower while oil prices were 1.4% higher than June 2010 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were up 17.1% from June 2010 averages

Underlying natural gas data furnished by:

ICE Global markets in clear view

Highlights (cont'd.)

- **Daily Net Commitment Period Compensation (NCPC)***
  - July payments total $19.4M over the period, up $12.5M from June
  - First Contingency payments total $16.3M, up $9.8M from June
    - $15.9M paid to internal resources, up $9.4M from June
      - $1.1M charged to DALO, $14.8M to RT Deviations
    - $434K paid to resources at external locations, up $327K from June
      - $388K charged to DALO at external locations, $46K to RT Deviation
  - Second Contingency payments total $35K
  - Voltage payments total $2.3M, up $2.1M from June
  - Distribution payments total $762K, up $652K from June
  - NCPC payments as percent of Energy Market value were 2.2%

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

Highlights (cont'd.)

- Written comments on the draft Regional System Plan 2010 (RSP10) report are due to ISO by August 5 and will be the focus of the Planning Advisory Committee (PAC) meeting planned for August 12
- The New England East-West Solution (NEEWS) Interstate Reliability Project will also be discussed at the August 12 PAC meeting
- The RSP Public Meeting scheduled for September 16 features a new format with panel discussions

Eastern Interconnection Planning Collaborative (EIPC)

- EIPC and DOE have agreed to contract terms and an agreement is in place
- Eastern Interconnection 10 year model development is essentially complete and analysis is underway to identify opportunities for improvement
  - A draft report is expected in October
- Stakeholder Steering Committee (SSC) held their first meeting in Chicago on July 15-16 with topics focused on structure and process
  - Discussed need for chairperson from the SSC ranks
  - Discussed SSC work scope
  - Agreed to formation of working groups to support various project efforts as a means of ensuring SSC can manage work scope

Highlights (cont'd.)

- The lowest Summer Operable Capacity Margin is being calculated for the week beginning September 11th.

Summer 2010 Highlights

Summer 2010 - Highlights

- Summer 2010 has already seen several hot days, including a heat wave during the week of July 5
  - Week of July 5th was an official heat wave
  - Record temperatures set in some areas
  - Peak load of 27,154 MW on July 6 was the 4th highest peak in New England
  - Peak load of 26,508 MW on July 7 was the 9th highest peak in New England

- Overall, the New England power system performed well

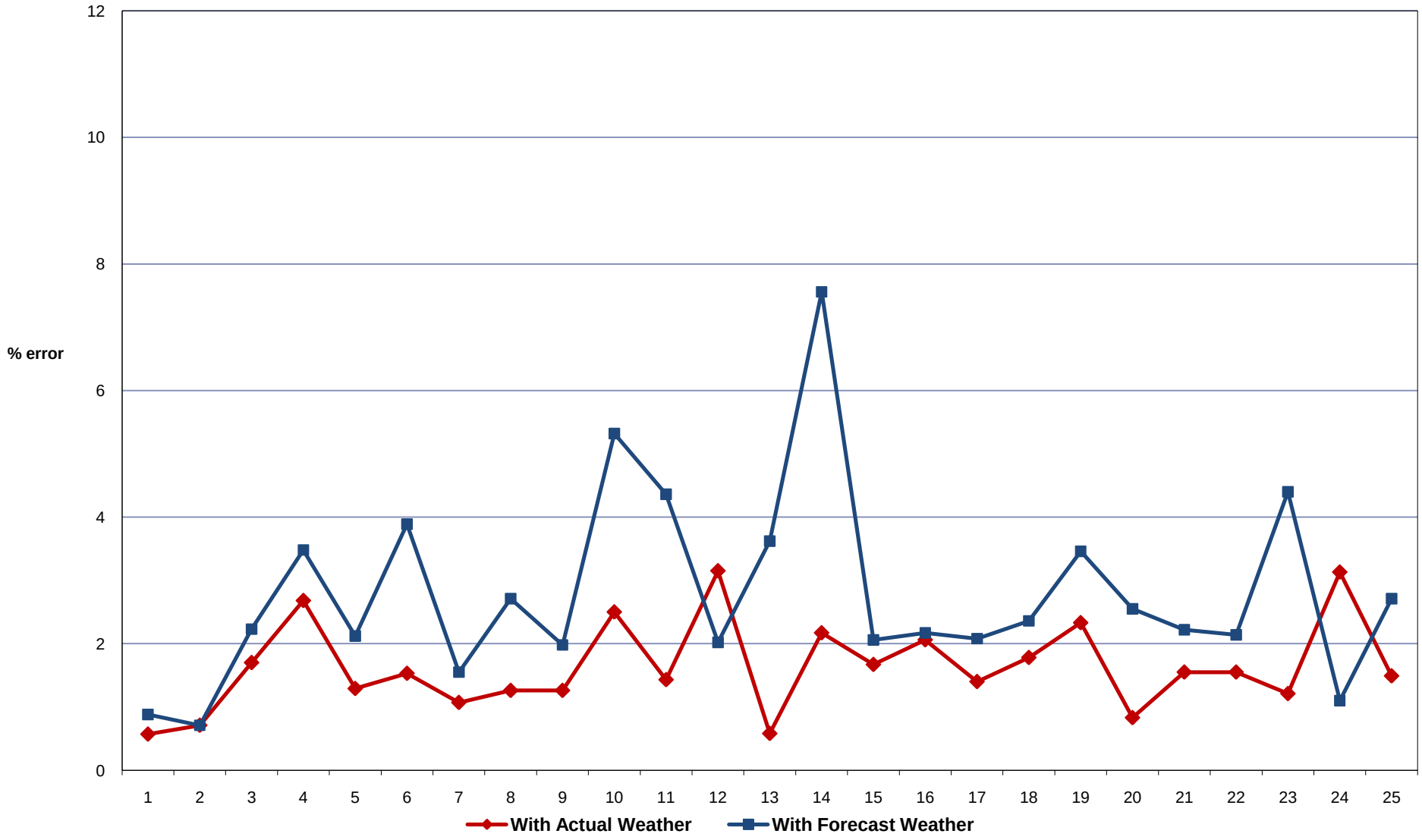
Summer 2010 - Highlights (cont'd.)

- Summer 2010 also marks the beginning of the first FCM commitment period and full integration of Demand Resources (DRI) into ISO operations
  - Demand Response (~670 MW) was called on June 24 to deal with a system-wide capacity deficiency situation
  - New Control Room applications, communications infrastructure and Operating Procedures and processes for FCM and DRI worked well

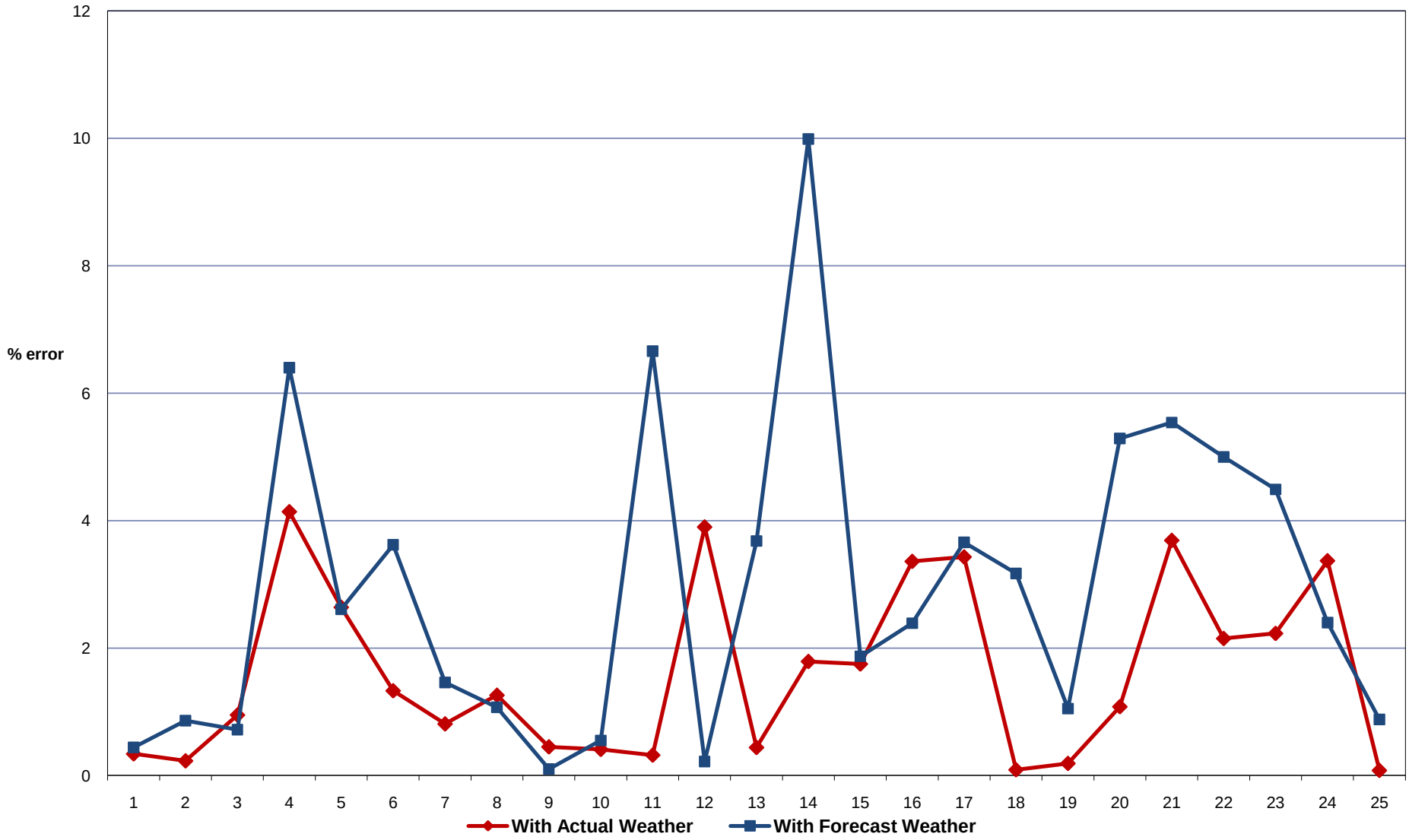
Summer 2010 - Highlights (cont'd.)

- Supplemental commitments have been much higher than in previous months due to the following reasons:
  - Extended outage of the Northfield Mountain station which normally provides significant reserves and load following capability
  - Weather forecast errors which drove load forecast errors (both average daily load forecast and peak daily load forecast)
  - On several days, the day-ahead market cleared lower levels of load than what was required to meet the day-ahead load forecast
  - Sufficient resources need to be committed for reliability day-ahead (during the Reserve Adequacy Assessment) due to the relative inflexibility (start-time) and ramp rate of several units

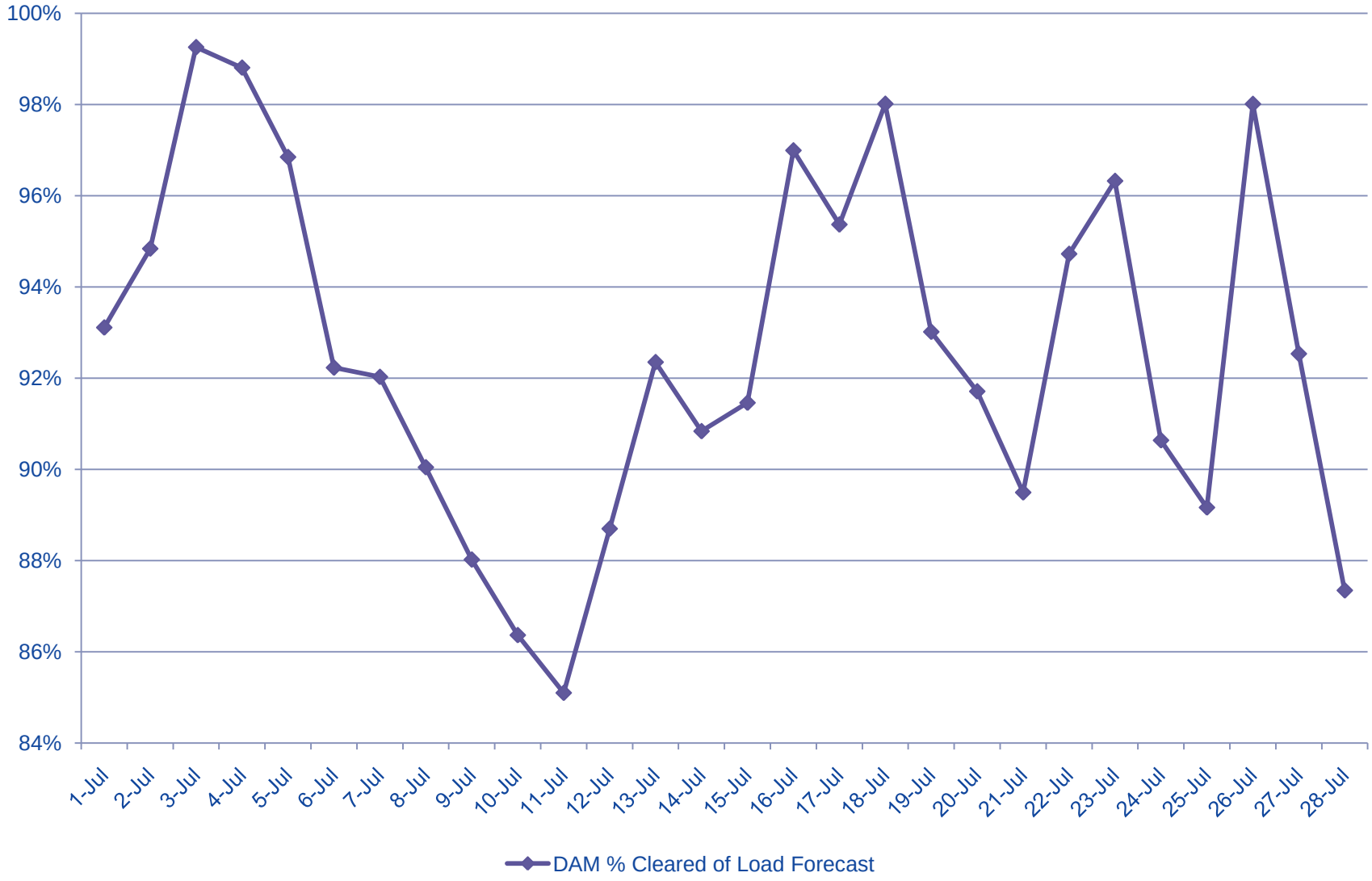
Daily Average Load Forecast Percent Error for July 2010
Monthly Average Error with Forecast Weather 2.8% and 1.6% with Actual



Load Forecast Percent Error at Hour of Daily Peak for July 2010
Monthly Average Error with Forecast Weather 3.0% and 1.6% with Actual



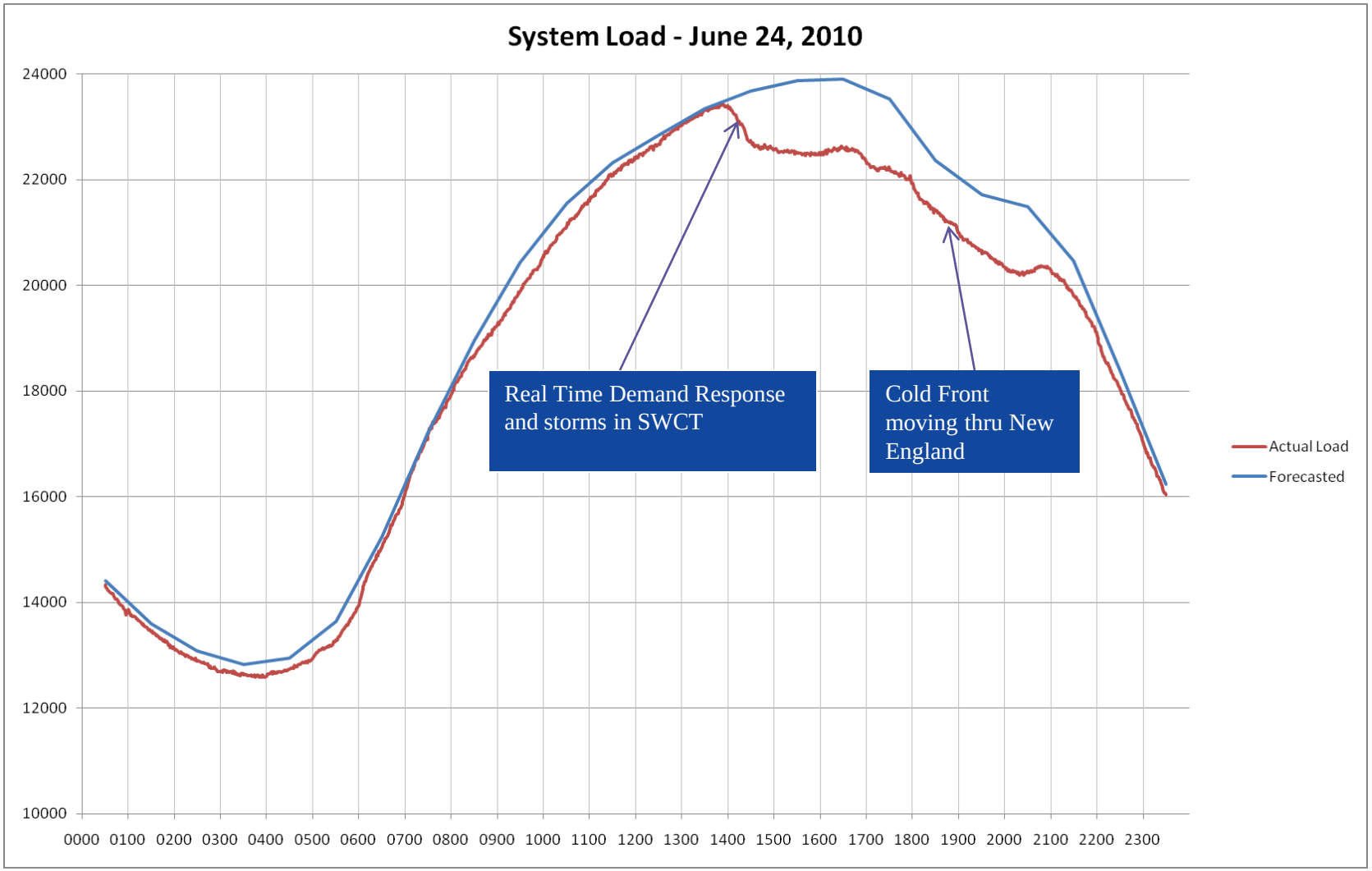
July 2010 - % of Forecasted Peak Cleared in Day Ahead



Capacity Deficiency Event #1: Thursday, June 24, 2010

- Operating Procedure #4, “Action During a Capacity Deficiency”, (OP-4) was implemented system-wide due to various generation reductions/outages over the course of the morning and early afternoon
  - Approximately 2000 MW of generator reductions/outages due to mechanical and operational issues
- Forecast peak load on June 24 was 23,900 MW
  - Actual peak load was 23,314 MW

System Load vs. Forecast



RTDR Obligation and Performance by Load Zone

Load Zone	Total Capacity Obligation	Average Aggregate Performance*	Percent RTDR Obligation
Connecticut	226.83	170	33.9
West Central Massachusetts	79.59	79	11.9
Northeast Massachusetts	70.74	46	10.6
Southeast Massachusetts	45.23	30	6.8
Rhode Island	27.76	27	4.1
Vermont	23.71	29	3.5
New Hampshire	29.11	33	4.4
Maine	166.22	239	24.8
New England	**669**	**653**	**100.0**

- Additional meter data corrections to address data quality issues will adjust the net performance.
- Additional analysis of individual resource performance is underway.

Capacity Deficiency Event #2: Monday, July 5, 2010

- OP-4 implemented system-wide due to load running approximately 1350 MW over the load forecast
- Forecast peak load on July 5 of 21,540 MW
  - Actual peak load was 22,903 MW

System Operations

System Operations

Weather Patterns:	Boston	Temperature – Above Average Precipitation – Average	Hartford	Temperature – Much above Avg* Precipitation – Below Average * (8 degrees above normal)

Peak Load:	27,154MW	**JULY 6, 2010**	15:00

Minimum Generation Emergencies : None

M/LCC2:

07/05 - Due to a Capacity Deficiency, 07/06 – Due to a Capacity Deficiency

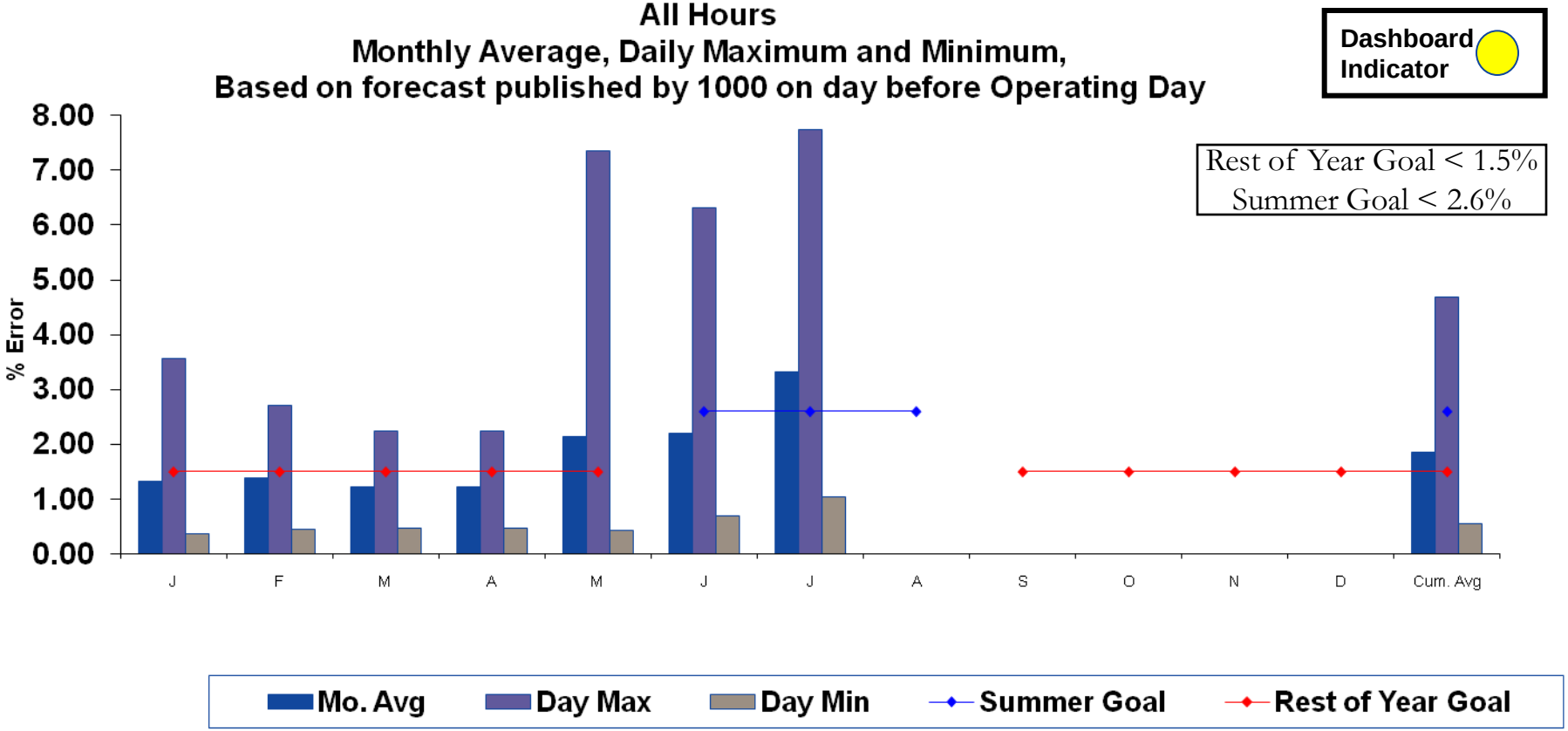
OP-4 :

07/05- Due to a Capacity Deficiency, Loads were 1400 MW over the forecasted curve on peak. Lost 350 MW of Generation. Implemented Action 1 only.

NPCC Shared Activation of Reserve Events:

July 07	PJM	1101 MW
July 07	NYISO	526 MW
July 21	IESO	940 MW
July 28	IESO	800 MW

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	2.21	3.32						1.86	Mo Avg
Day Max	3.57	2.72	2.62	2.24	7.35	6.32	7.73						4.68	Day Max
Day Min	0.37	0.45	0.43	0.48	0.44	0.70	1.05						0.56	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	
Current Summer Goal Avg													2.77	

Contact: Steve Weaver

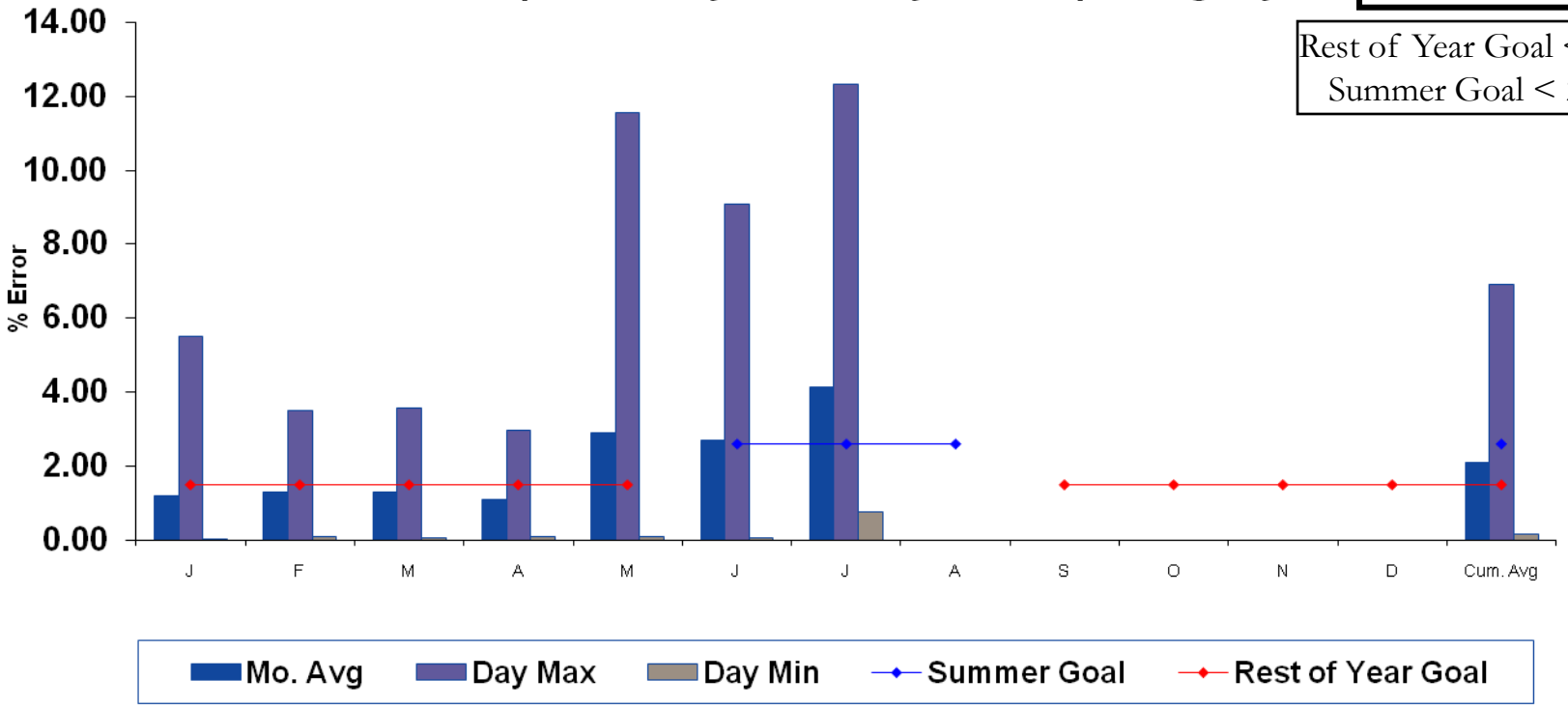
Summer Goal = 2.6% Rest of Year(ROY) Goal = 1.5%
Summer consists of June, July and August-

2010 System Operations - Load Forecast Accuracy cont.

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

Dashboard Indicator

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



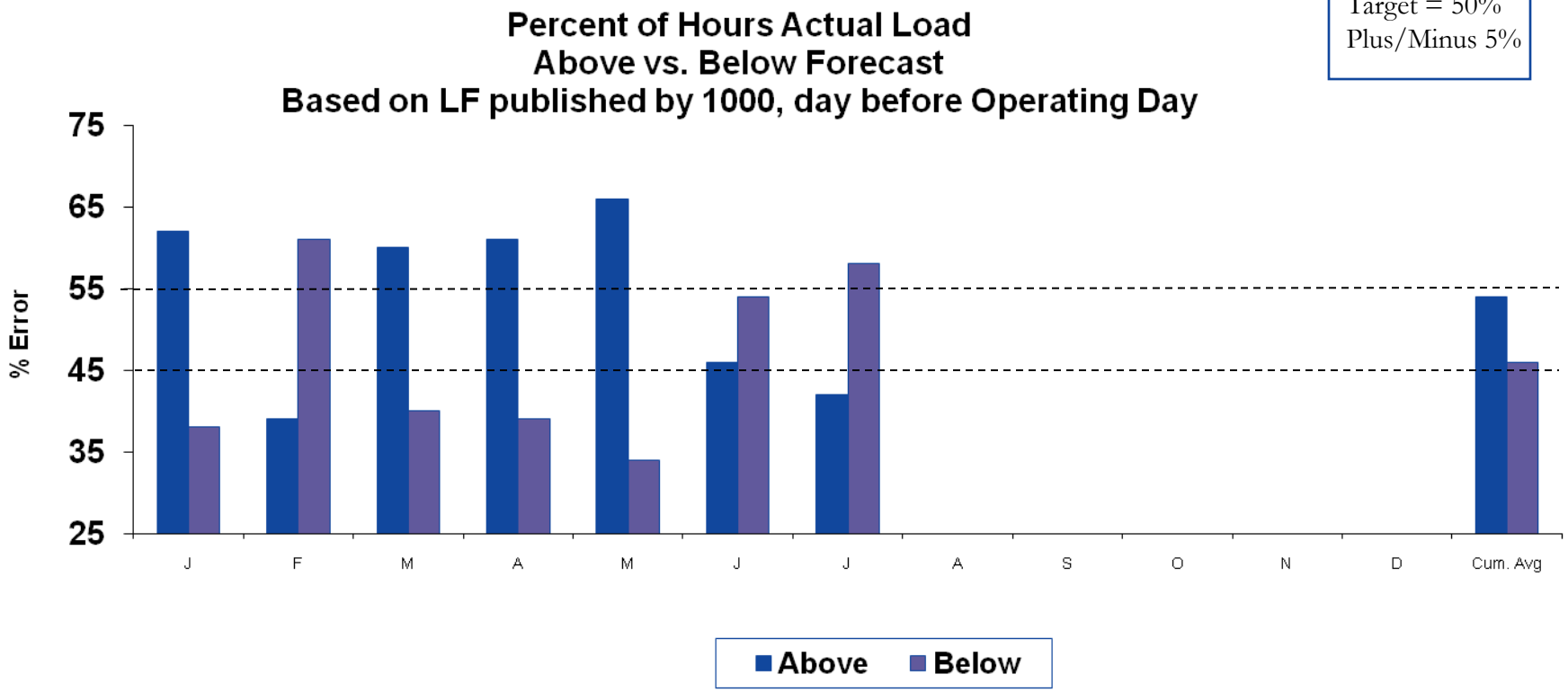
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.20	1.28	1.28	1.10	2.88	2.71	3.82						2.05
Day Max	5.49	3.49	3.55	2.95	11.56	9.07	12.34						6.98
Day Min	0.03	0.07	0.05	0.07	0.08	0.06	0.36						0.10
Summer Goal						2..6	2.6	2.6					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Current YTD ROY													**1.55**
Current Summer Goal Avg													3.27

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%

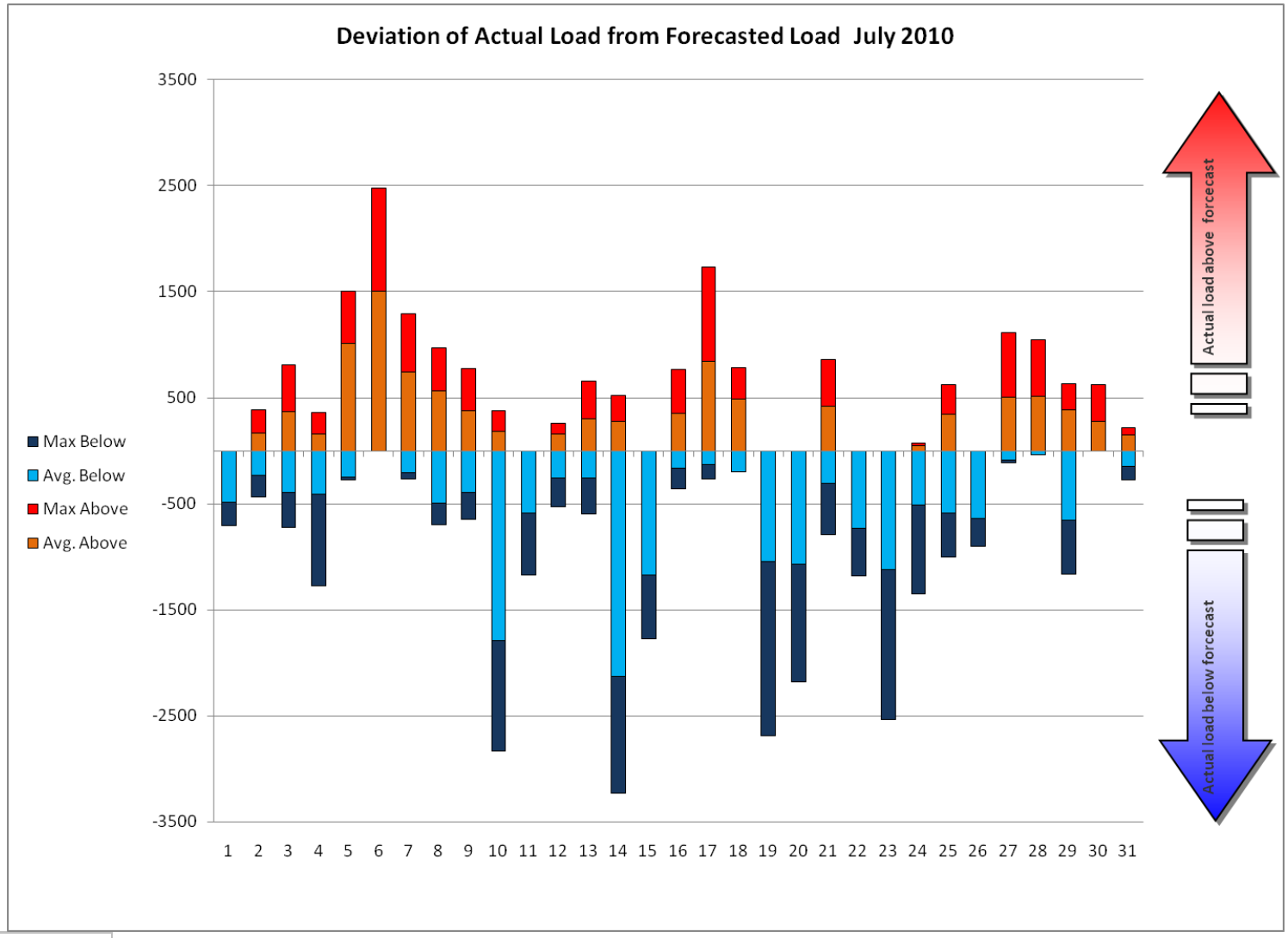


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	62.0	39.0	60.0	61.0	66.0	46.0	42.0						54.0
Below %	38.0	61.0	40.0	39.0	34.0	54.0	58.0						46.0
Avg Above	178.0	106.0	144.0	147.0	258.0	198	327						193.0
Avg Below	-112.0	-181.0	-118.0	-103.0	-155.0	-314	-533						-211.0
Avg All	74.0	-69.0	38.0	45.0	107.0	-91.0	-166.0						-5.0

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

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

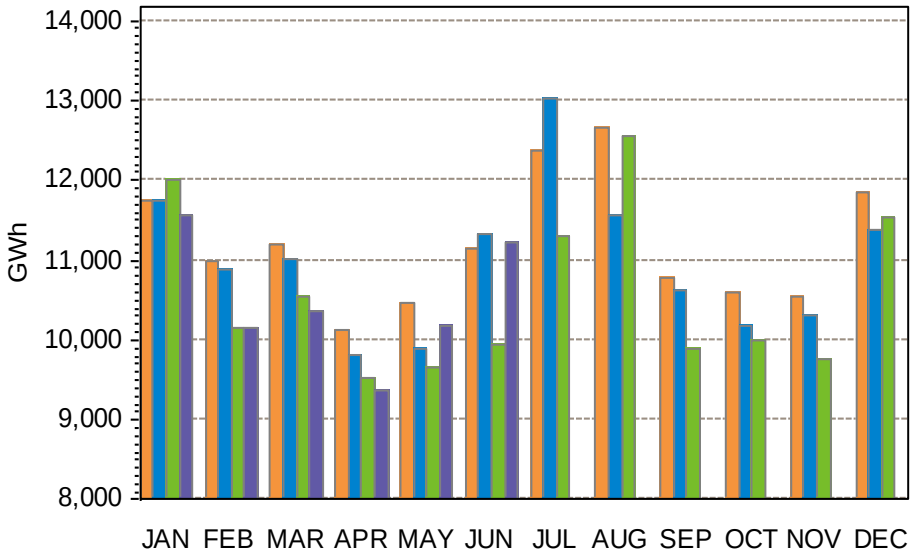
2010 System Operations - Load Forecast Accuracy



Sponsor	Mike Taniwha
Contact	Steve Weaver

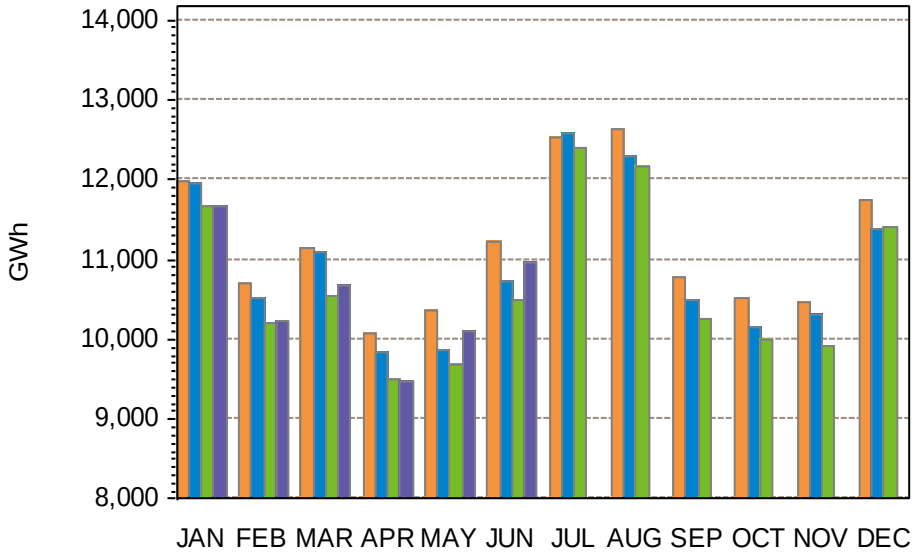
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

Net Energy for Load (NEL)



Ann Tot (TWh):	134.5	131.7	126.8	62.8

Weather Normalized NEL

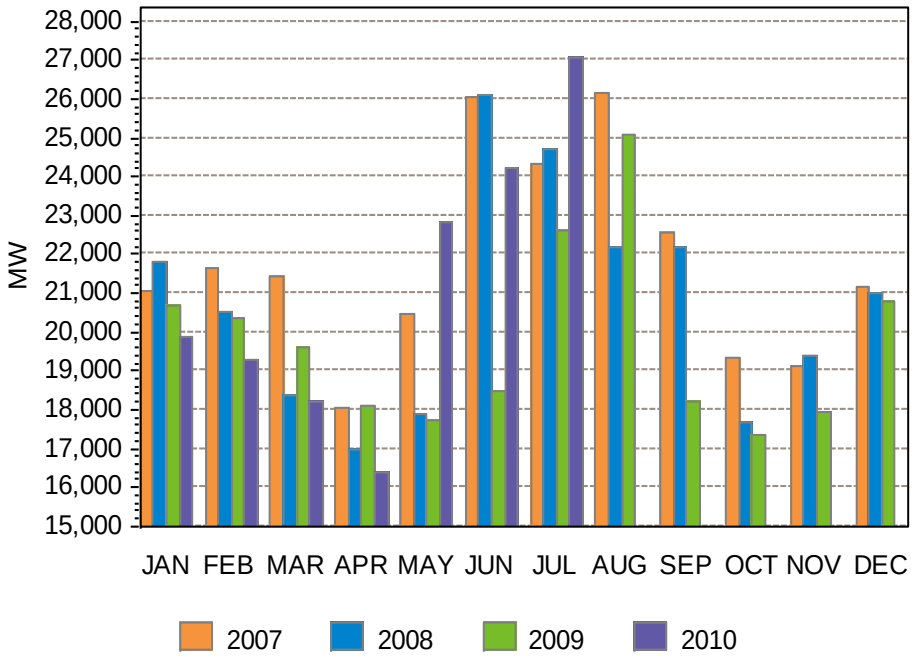


Ann Tot (TWh):	134.2	131.2	128.3	63.1

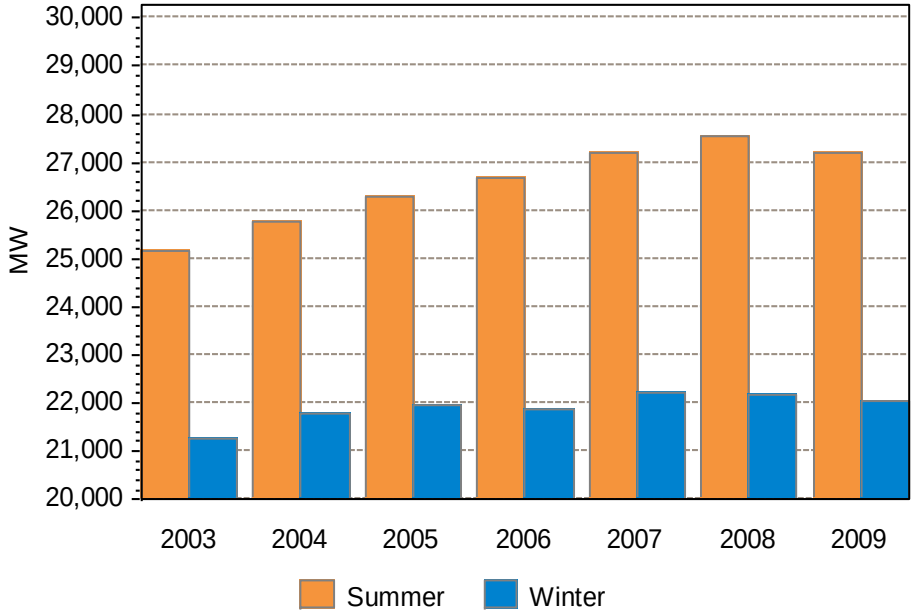
NEPOOL NEL is the total net energy required to serve load for the month, in GWh. NEL is calculated as: Generation – pumping load + net interchange. Reported on a one month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History

System Peak Load



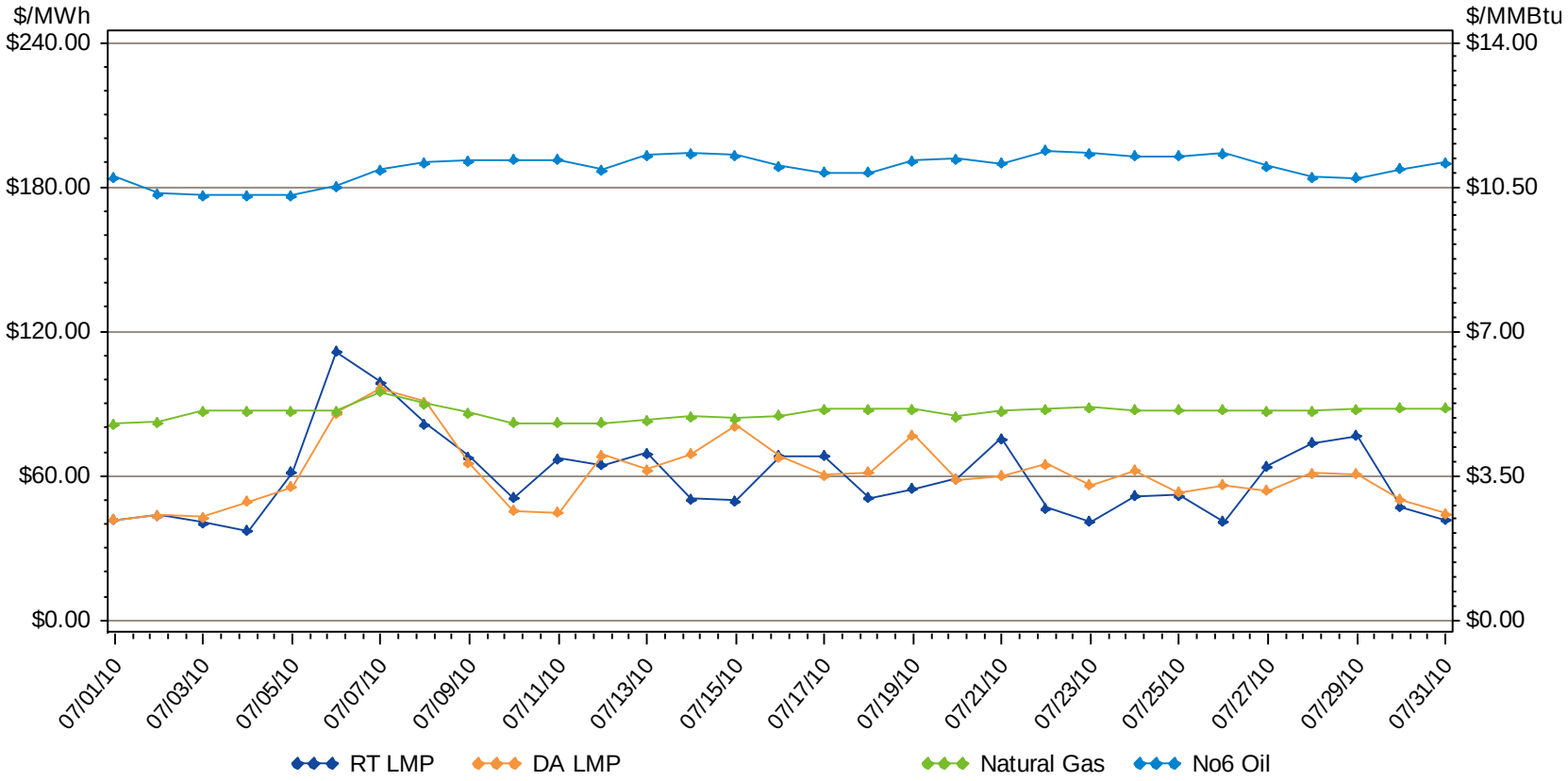
Weather Normalized Seasonal Peaks



Winter beginning in year displayed

Market Operations

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

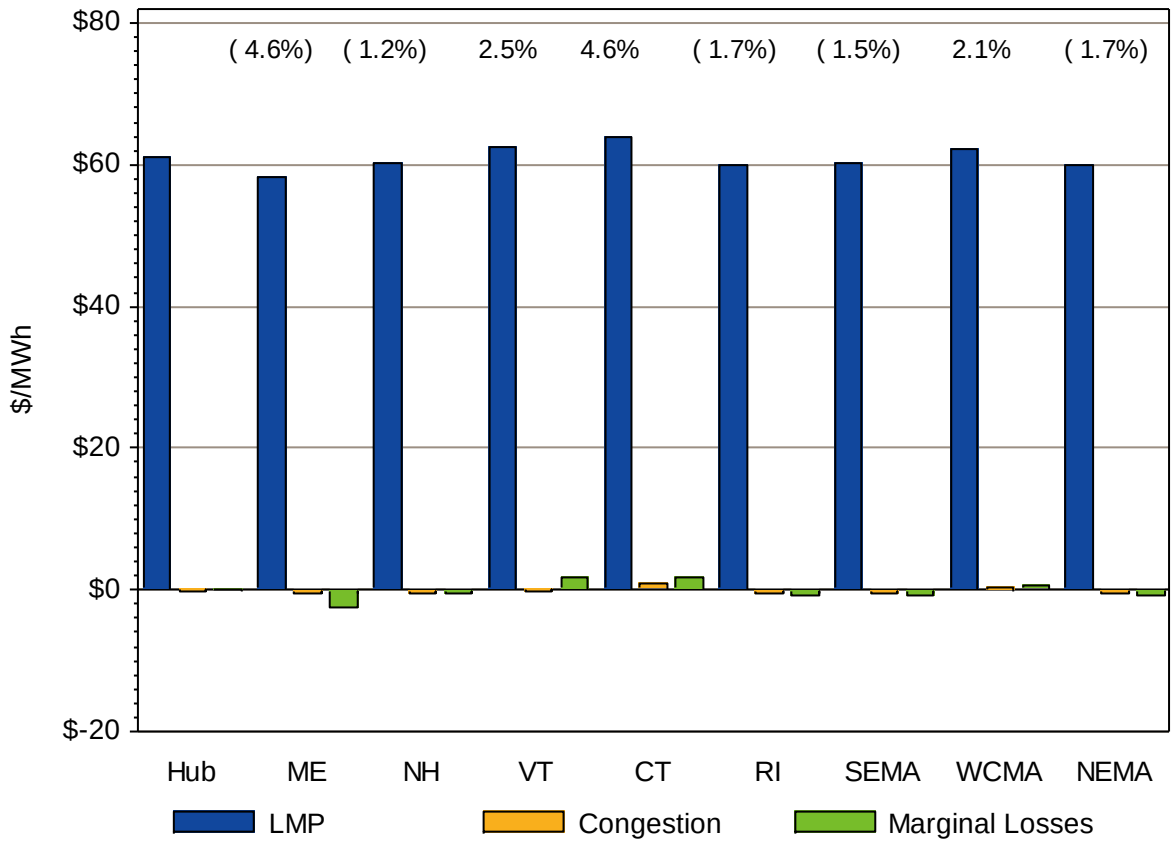


Underlying natural gas data furnished by:

ICE Global markets in clear view

Average price difference over this period (DA-RT): $1.33
Average price difference over this period ABS(DA-RT): $10.05
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

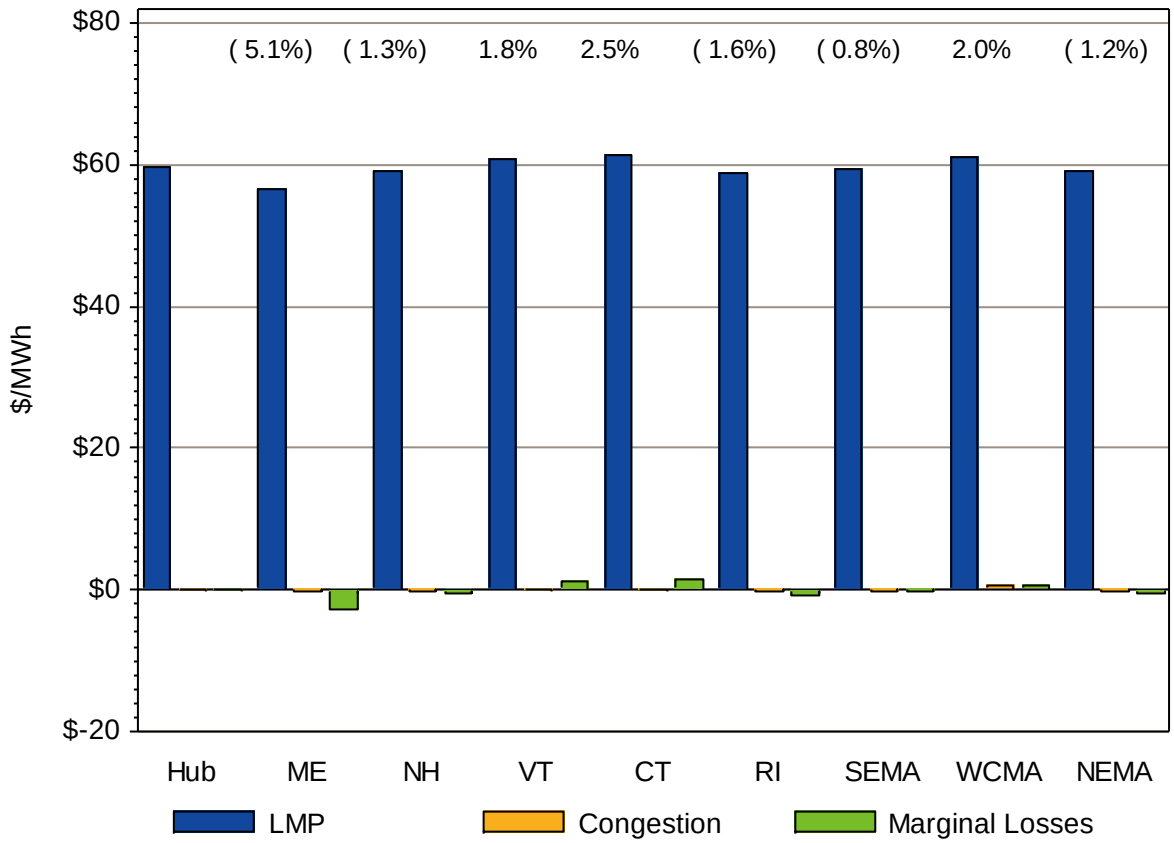
DA LMPs Average by Zone & Hub – July 2010



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

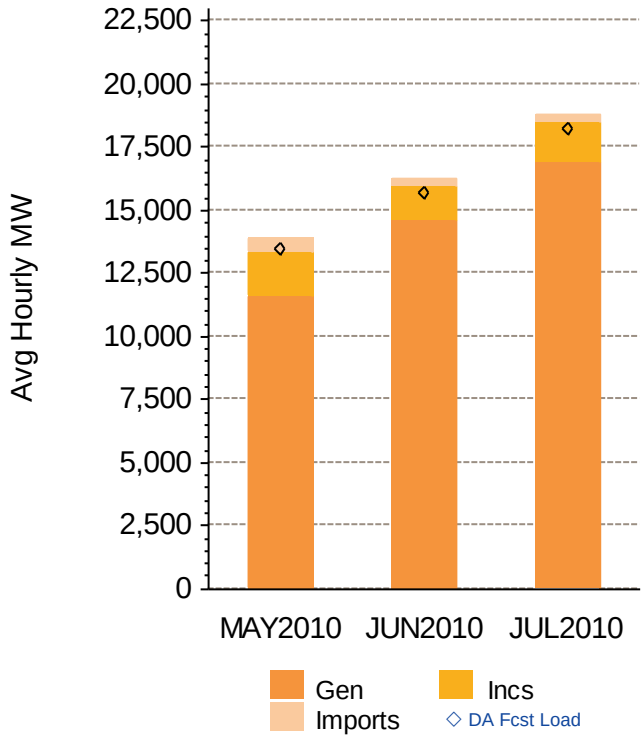
RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

RT LMPs Average by Zone & Hub – July 2010



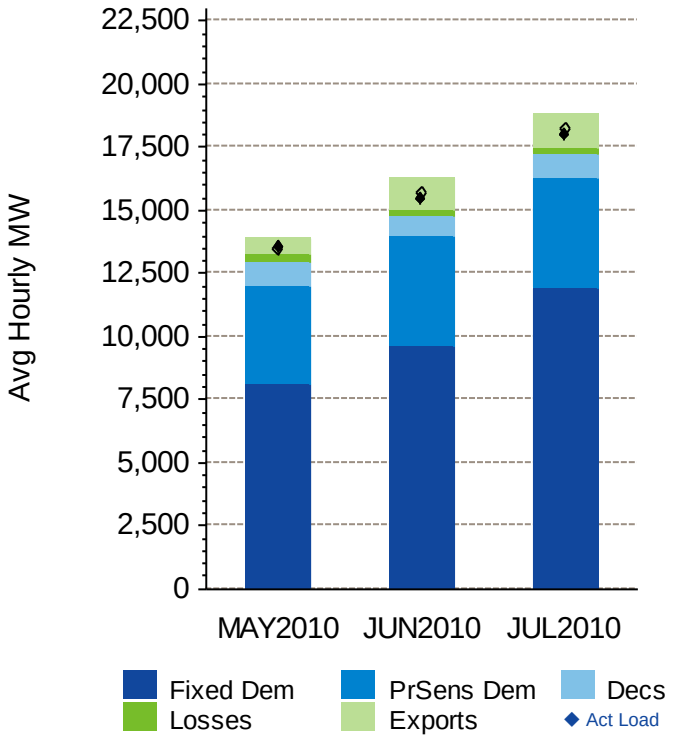
Components of Cleared DA Supply and Demand – Last Three Months

Supply



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

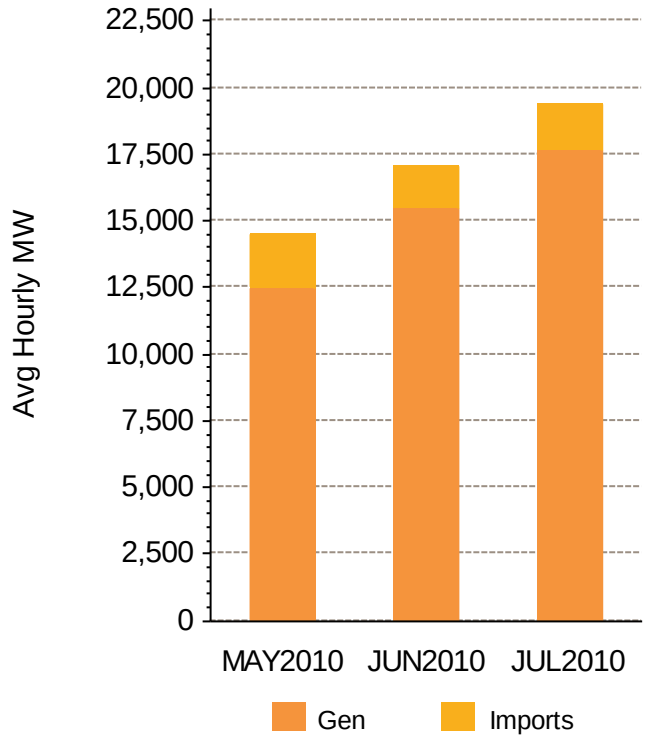
Demand



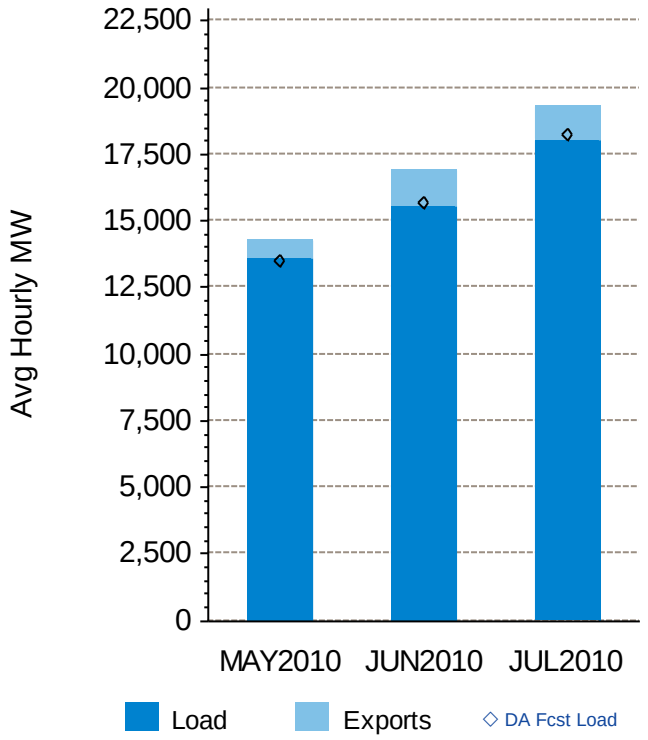
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months

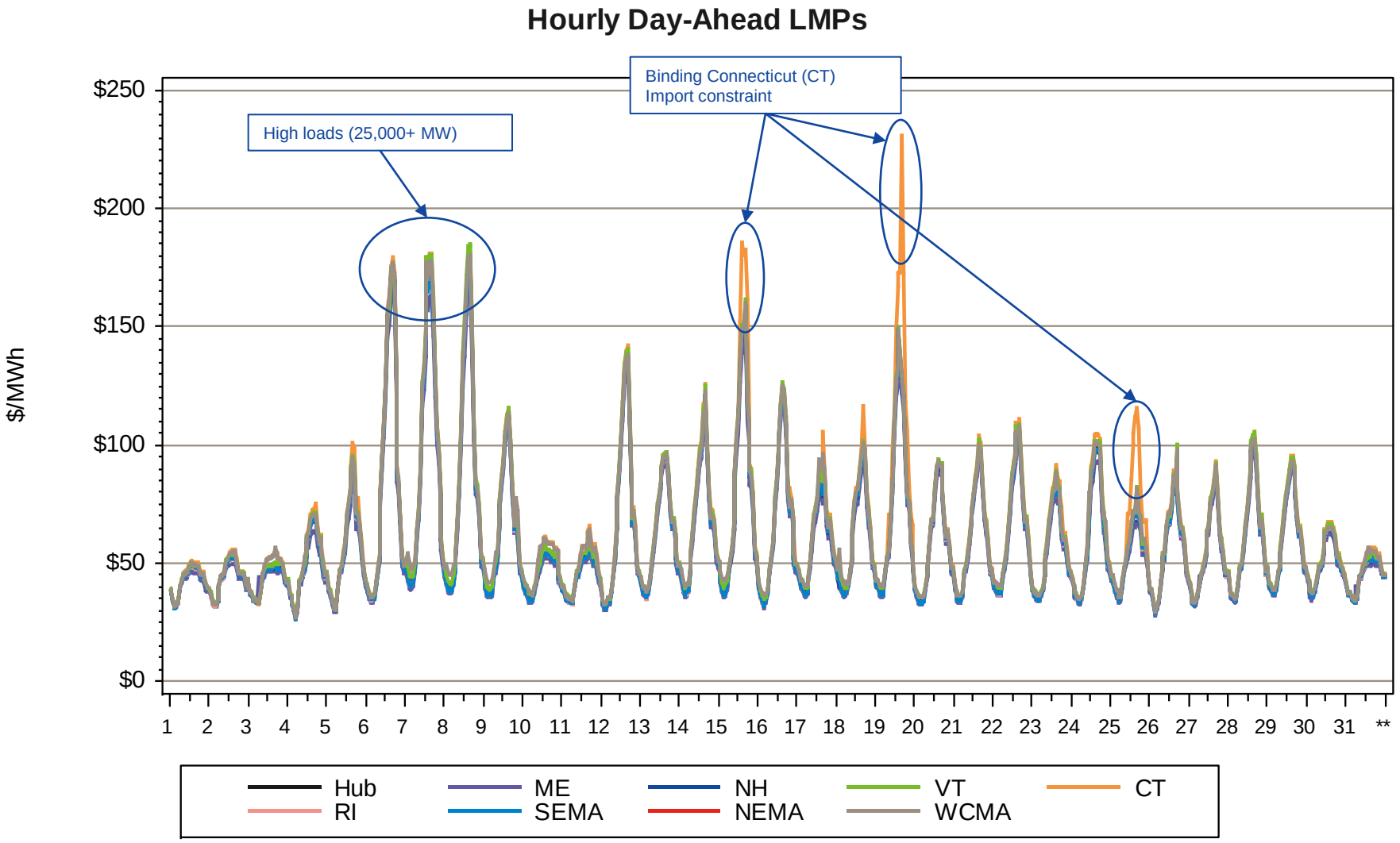
Supply



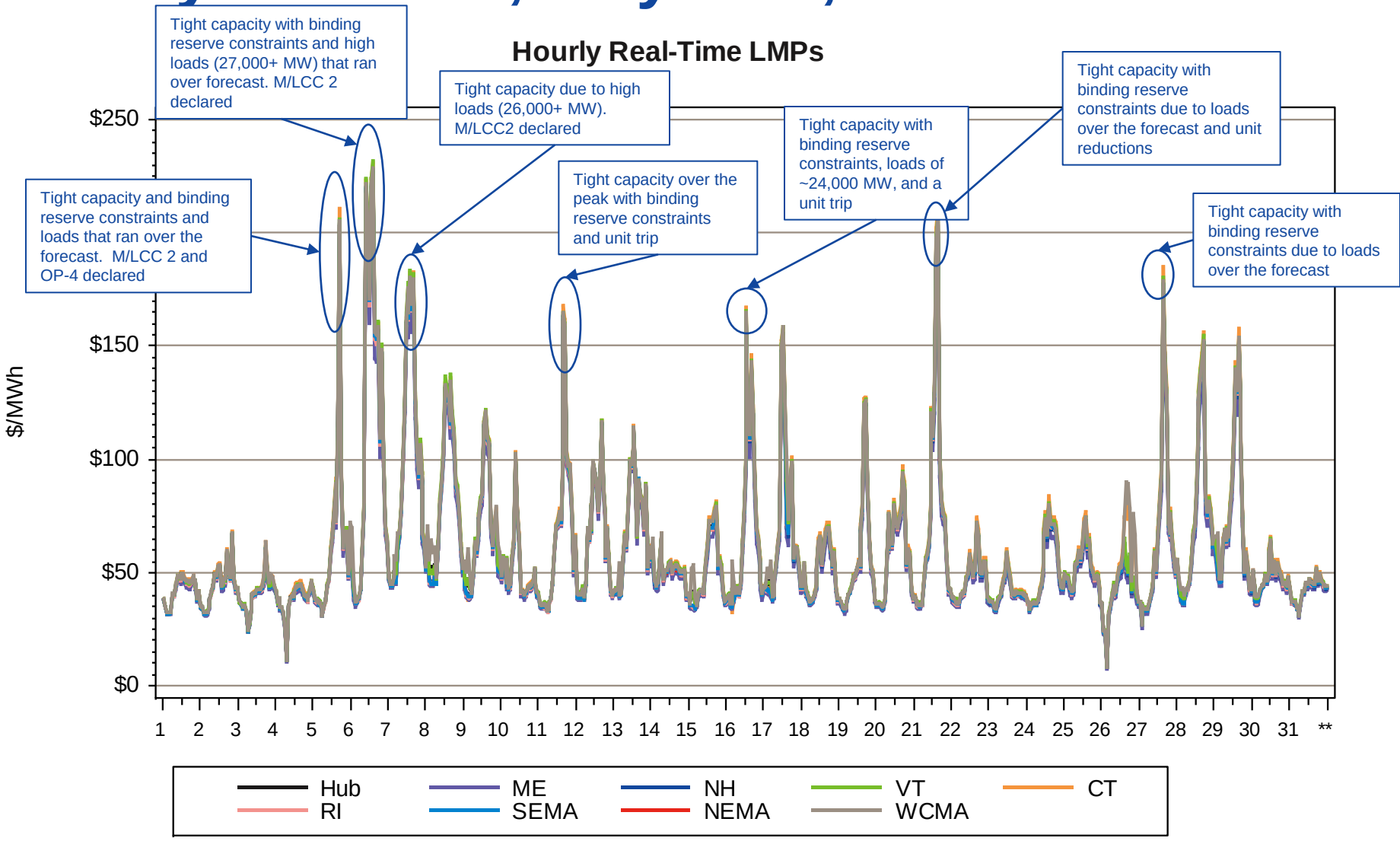
Demand



Hourly DA LMPs, July 1-31, 2010

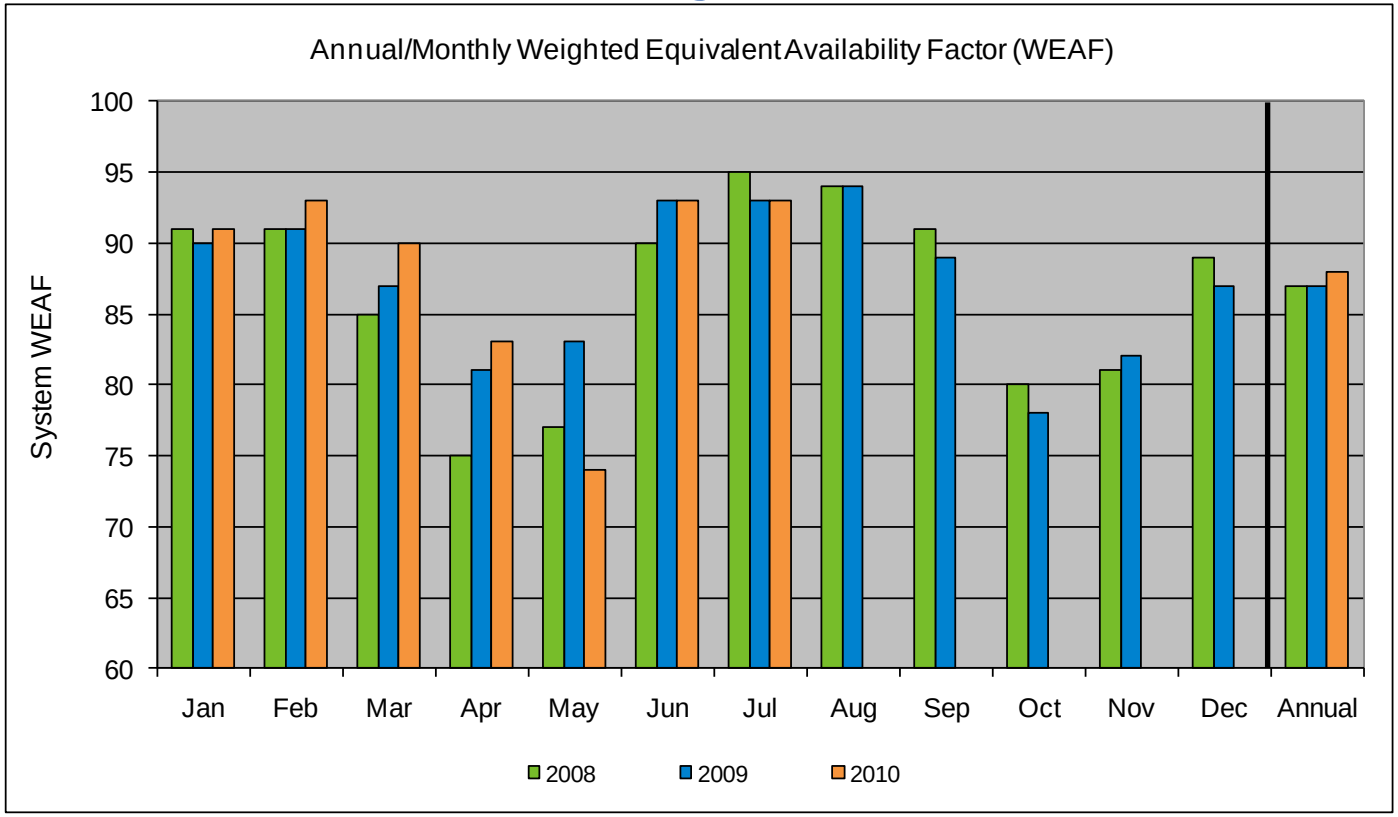


Hourly RT LMPs, July 1-31, 2010



System Unit Availability

Dashboard Indicator



Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	YTD	
91	93	90	83	74	93	93						88	**2010**
												87	**2009**
												87	**2008**
												90	**2007**

DEFINITION: System Weighted Average Availabiltiy Factor of New England Generating Units
FORMULA: (1 - System Forced Outage Rate)*(1 - System Scheduled Outage Rate)
Data current as of 07/30/2010
Sponsor: Steve Rourke
Contact: Susan Haas

Back-up Detail

Load Response

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

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	165.71	17.59	19.83	0.00	203.13
NH	27.69	21.57	32.42	0.00	81.68
VT	23.35	10.32	41.74	0.00	75.41
CT	219.48	255.13	56.82	108.53	639.97
RI	27.76	39.40	34.46	0.00	101.62
SEMA	39.34	35.71	60.85	0.00	135.90
WCMA	81.05	56.62	56.22	9.48	203.37
NEMA	67.61	66.63	97.73	0.00	231.97
Total	**669.41**	**522.39**	**406.24**	**118.01**	**1,716.05**

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

New Generation

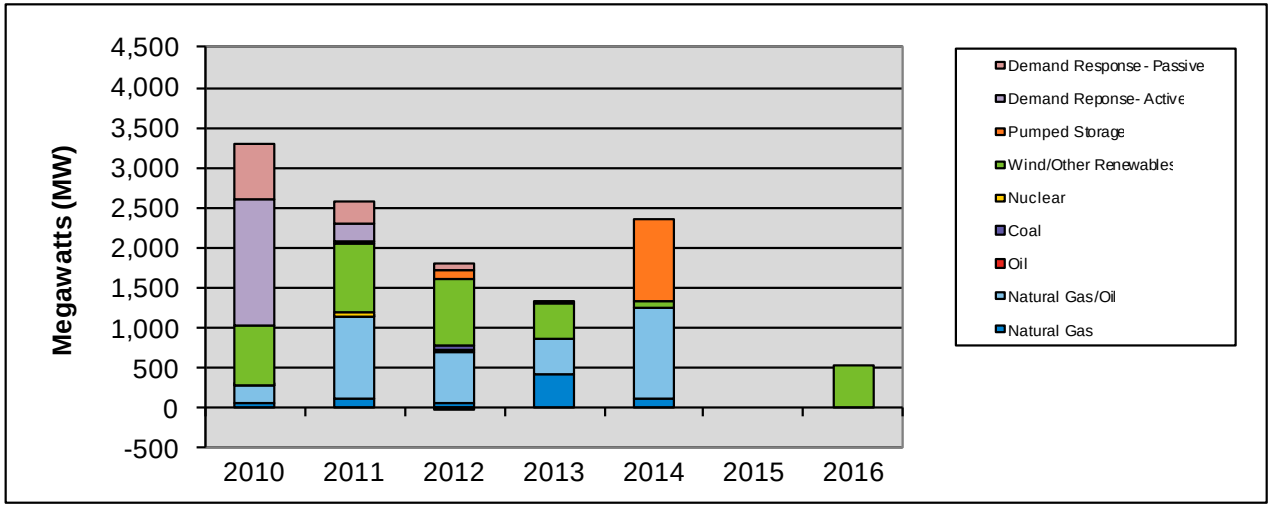
New Generation Update

- One 33 MW new generation project and one 12 MW generator upgrade project has applied for interconnection study since the last update
  - The new generation project is a biomass facility while the upgrade is being done on a natural gas facility
  - Projected in-service dates are in 2013 and 2011 respectively
- Four projects, totaling approximately 250 MW went commercial, while five projects, totaling approximately 500 MW withdrew from the queue
- In total, 89 generation projects are currently being tracked by the ISO, totaling approximately 8,800 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

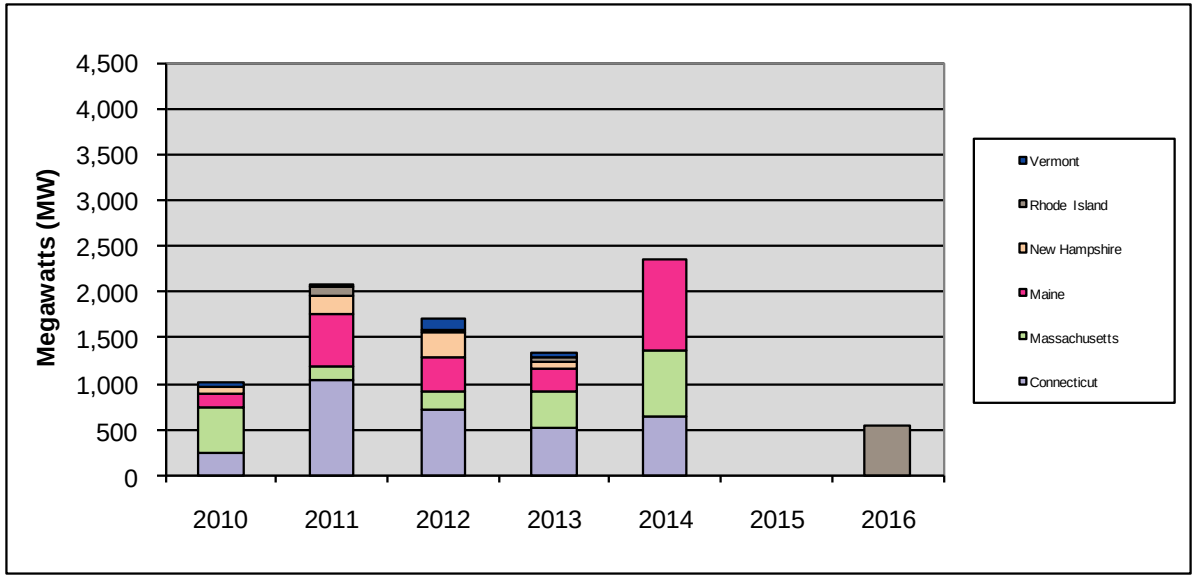


	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Demand Response - Passive	700	278	95	0	0	0	0	1,073	9.0
Demand Response - Active	1,579	221	-6	0	0	0	0	1,794	15.1
Pumped Storage	0	25	111	25	1,025	0	0	1,186	10.0
Wind & Other Renewables	726	869	839	460	91	0	536	3,521	29.5
Nuclear	0	45	0	0	0	0	0	45	0.4
Coal	17	0	36	0	0	0	0	53	0.4
Oil	0	13	30	0	0	0	0	43	0.4
Natural Gas/Oil	218	1,018	640	444	1,131	0	0	3,451	29.0
Natural Gas	54	120	60	411	107	0	0	752	6.3
Totals	**3,294**	**2,589**	**1,805**	**1,340**	**2,354**	**0**	**536**	**11,918**	**100.0**

- 2010 values include the 292 MW of generation that has gone commercial in 2010
- Active DR value reflects the 600 MW limit on Real-Time Emergency Generation resources

Actual and Projected Annual Generator Capacity Additions

By State



	2010	2011	2012	2013	2014	2015	2016	Total	% of Total
Vermont	61	25	129	64	0	0	0	279	3.1
Rhode Island	0	101	34	29	0	0	536	700	7.7
New Hampshire	59	218	267	86	0	0	0	630	7.0
Maine	162	550	377	251	1,000	0	0	2,340	25.9
Massachusetts	492	153	183	405	719	0	0	1,952	21.6
Connecticut	241	1,043	726	505	635	0	0	3,150	34.8
Totals	**1,015**	**2,090**	**1,716**	**1,340**	**2,354**	**0**	**536**	**9,051**	**100.0**

- 2010 values include the 292 MW of generation that has gone commercial in 2010

New Generation Projection
By Fuel Type

Fuel Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	14	462	1	38	13	424
Coal	1	36	0	0	1	36
Hydro	8	1,219	0	24	8	1,195
Landfill Gas	1	34	0	0	1	34
Natural Gas	9	721	0	0	9	721
Natural Gas/Oil	13	3,233	3	943	10	2,290
Nuclear Uprates	2	45	0	0	2	45
Oil	2	43	0	0	2	43
Solar	0	0	0	0	0	0
Wind	33	2,966	4	180	29	2,786
Total	83	8,759	8	1,185	75	7,574

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

New Generation Projection
By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	19	586	1	38	18	548
Intermediate	17	3,349	1	644	16	2,705
Peaker	14	1,858	2	323	12	1,535
Wind Turbine	33	2,966	4	180	29	2,786
Total	83	8,759	8	1,185	75	7,574

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

New Generation Projection
By Operating Type and Fuel Type

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	14	462	14	462	0	0	0	0	0	0
Coal	1	36	1	36	0	0	0	0	0	0
Hydro	8	1,219	0	0	5	33	3	1,186	0	0
Landfill Gas	1	34	1	34	0	0	0	0	0	0
Natural Gas	9	721	1	9	4	679	4	33	0	0
Natural Gas/Oil	13	3,233	0	0	8	2,637	5	596	0	0
Nuclear Uprates	2	45	2	45	0	0	0	0	0	0
Oil	2	43	0	0	0	0	2	43	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Wind	33	2,966	0	0	0	0	0	0	33	2,966
Total	83	8,759	19	586	17	3,349	14	1,858	33	2,966

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?

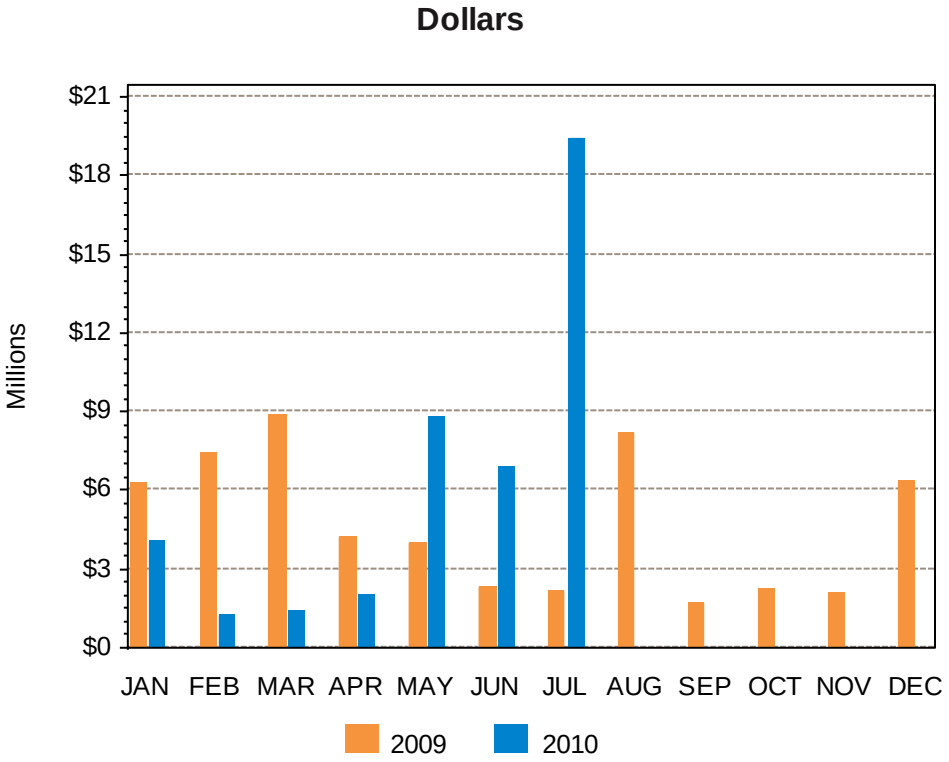
- "Make-whole" payments made to resources whose hourly commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output over the course of the day

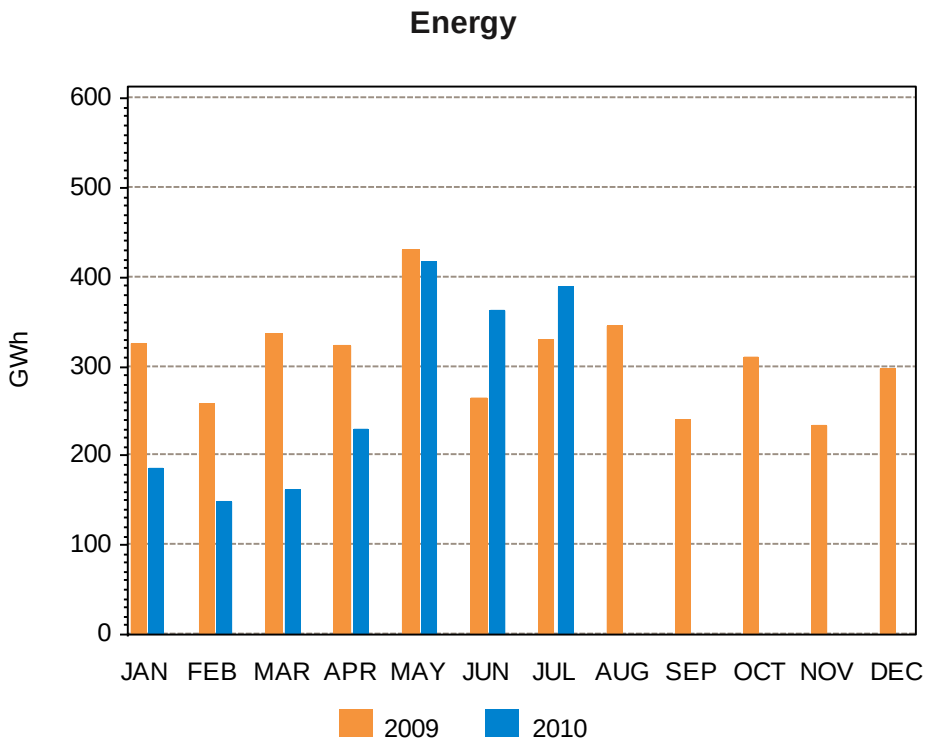
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area

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

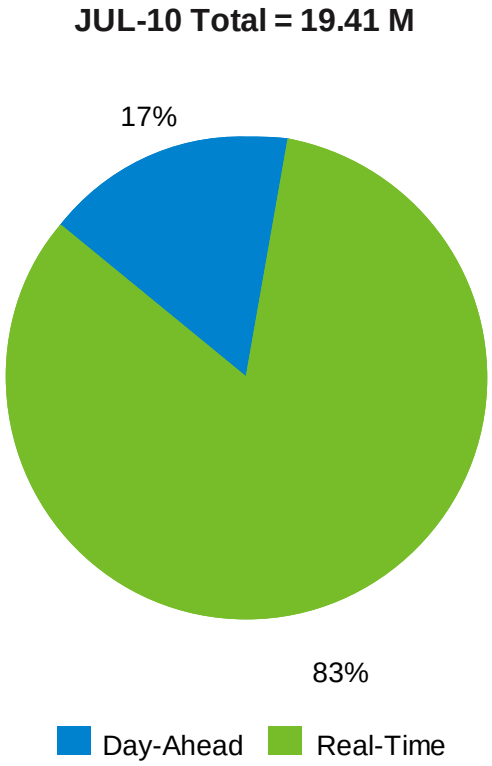


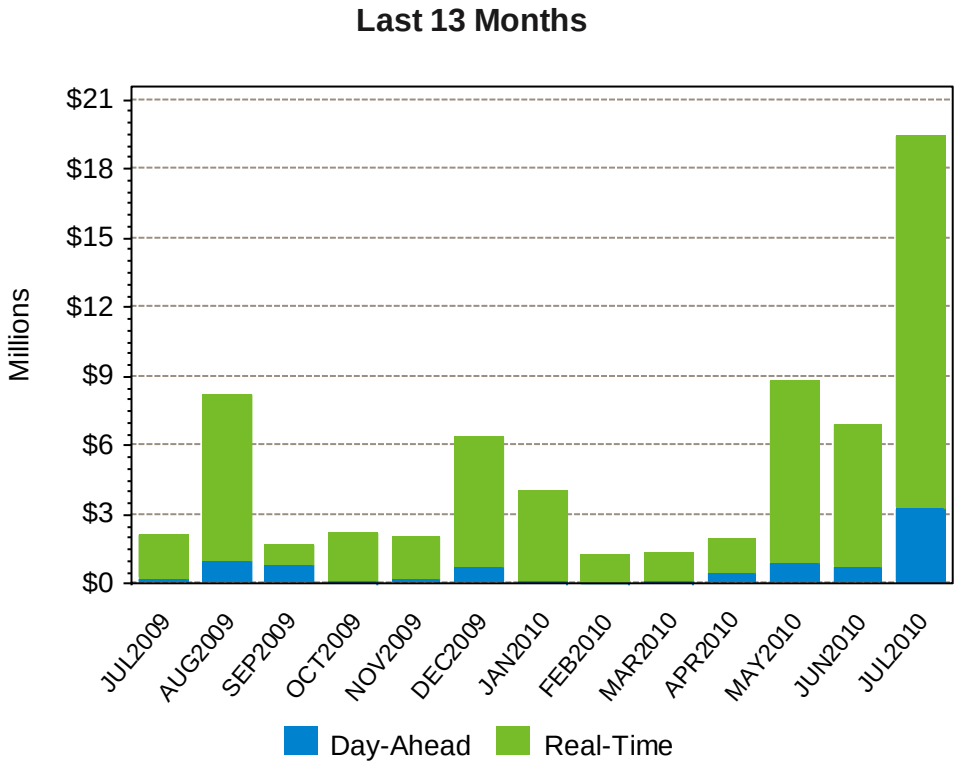


Note:

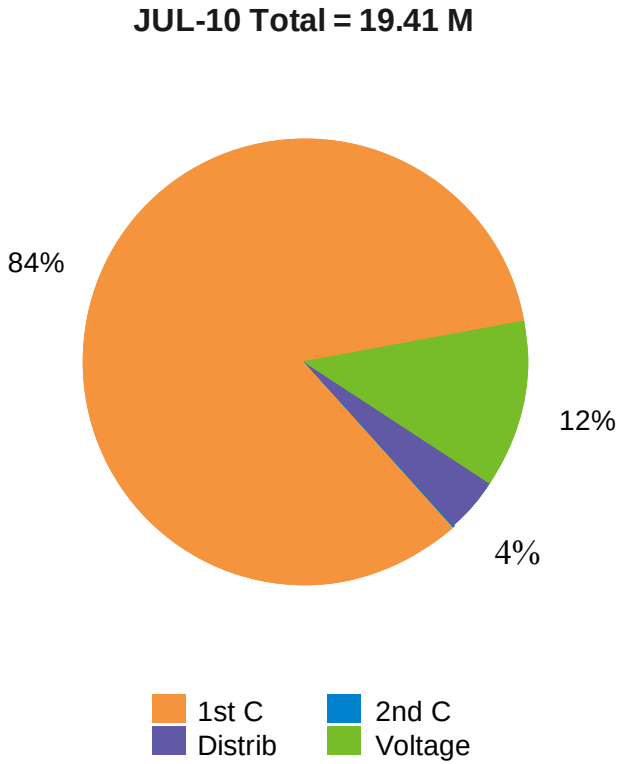
- Overall Reliability Cost MWh includes out of merit DA and RT 1st Contingency, 2nd Contingency, Voltage, and RT Distribution components.
- Energy includes daily totals of cleared DA energy and RT energy from resources receiving NCPC payments.

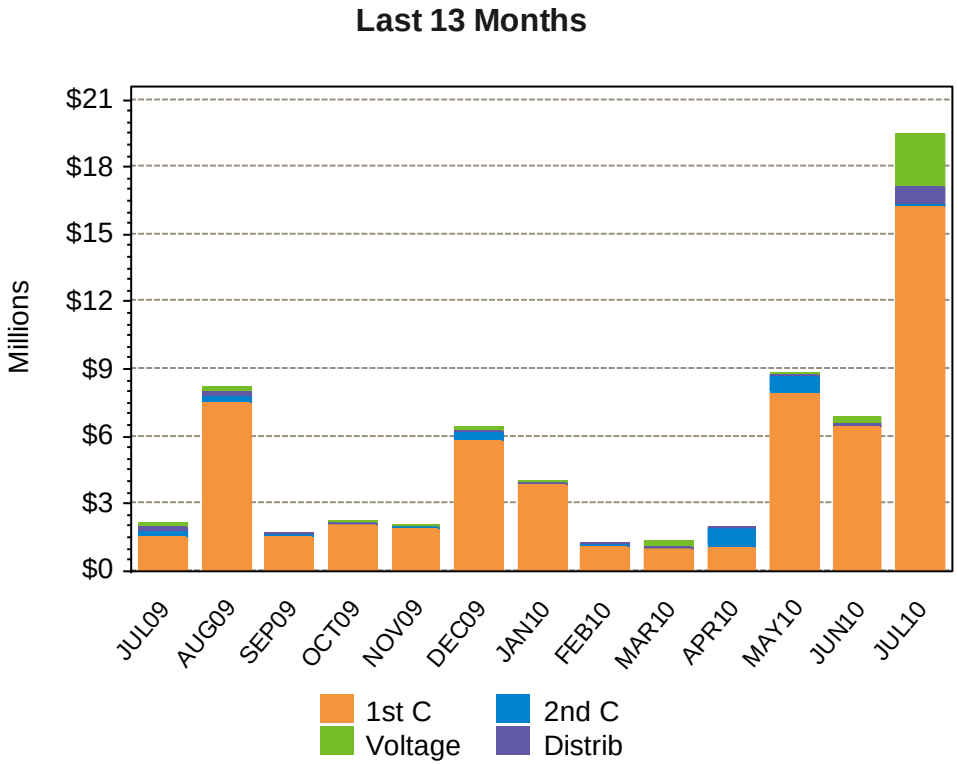
DA and RT NCPC Payments





NCPC Payments by Type

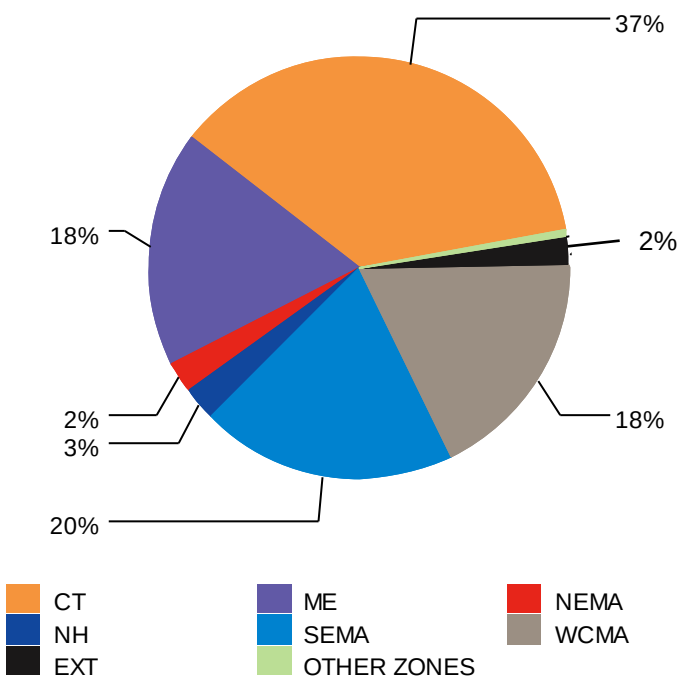




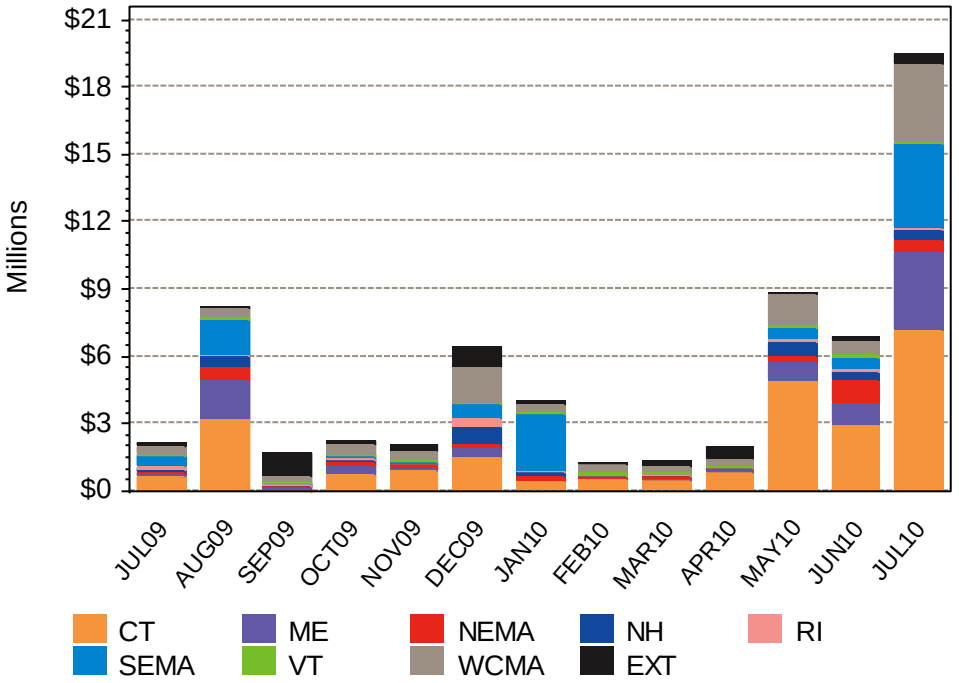
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage Support

NCPC Payments by Location

JUL-10 Total = 19.41 M



Last 13 Months

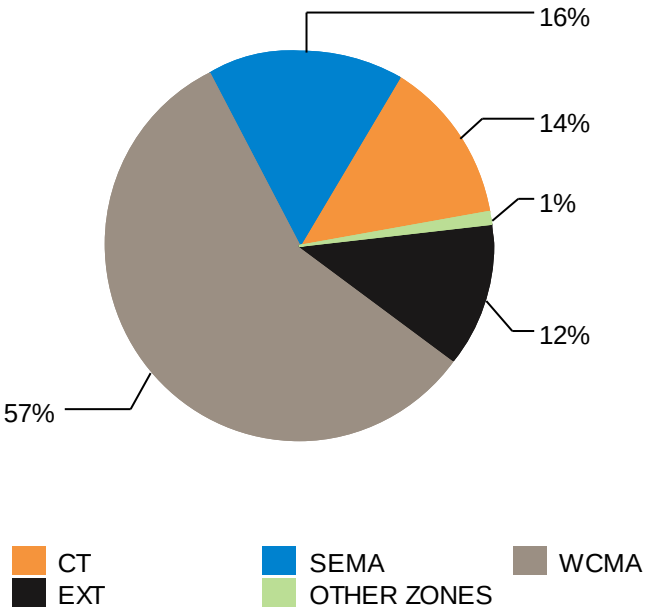


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region

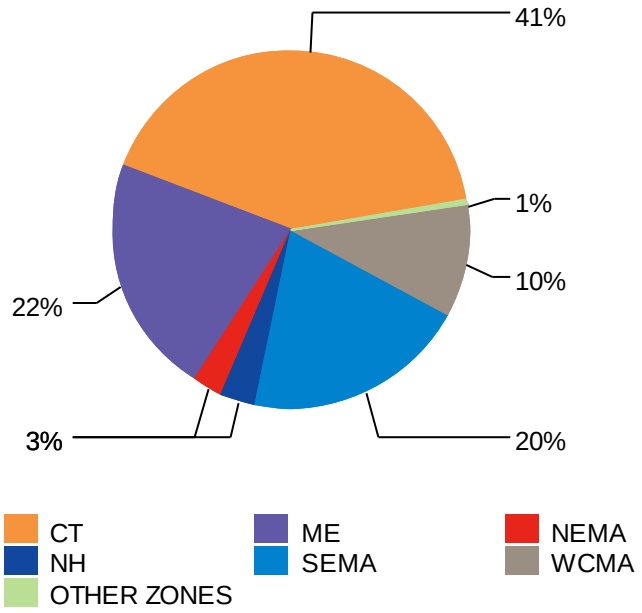
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

DA and RT NCPC Payments by Location

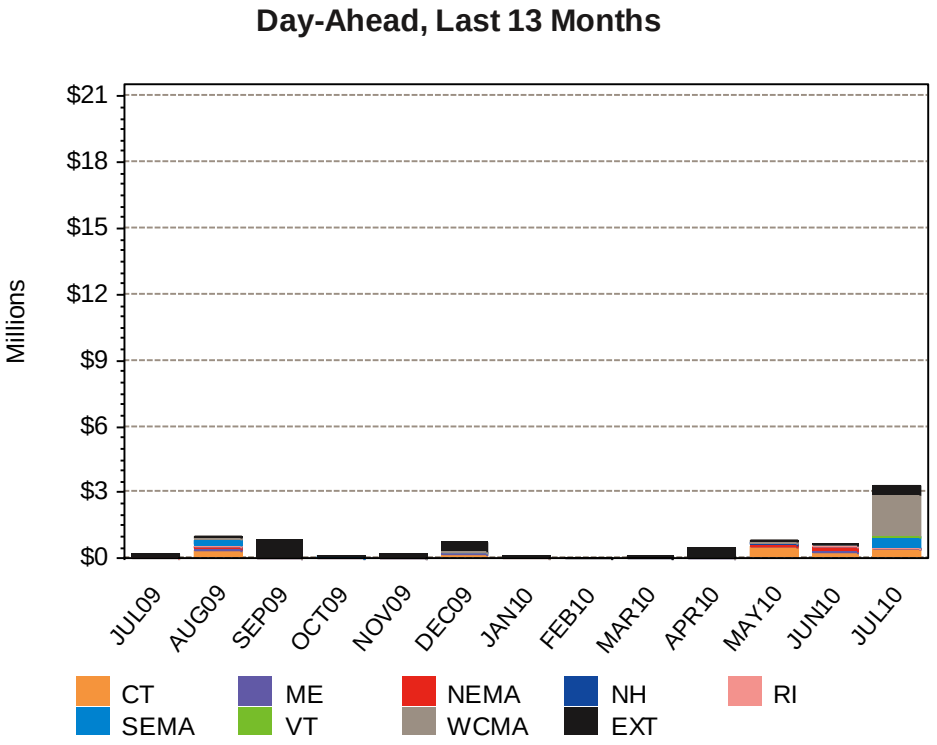
JUL-10 Day-Ahead Total = $3.28 M

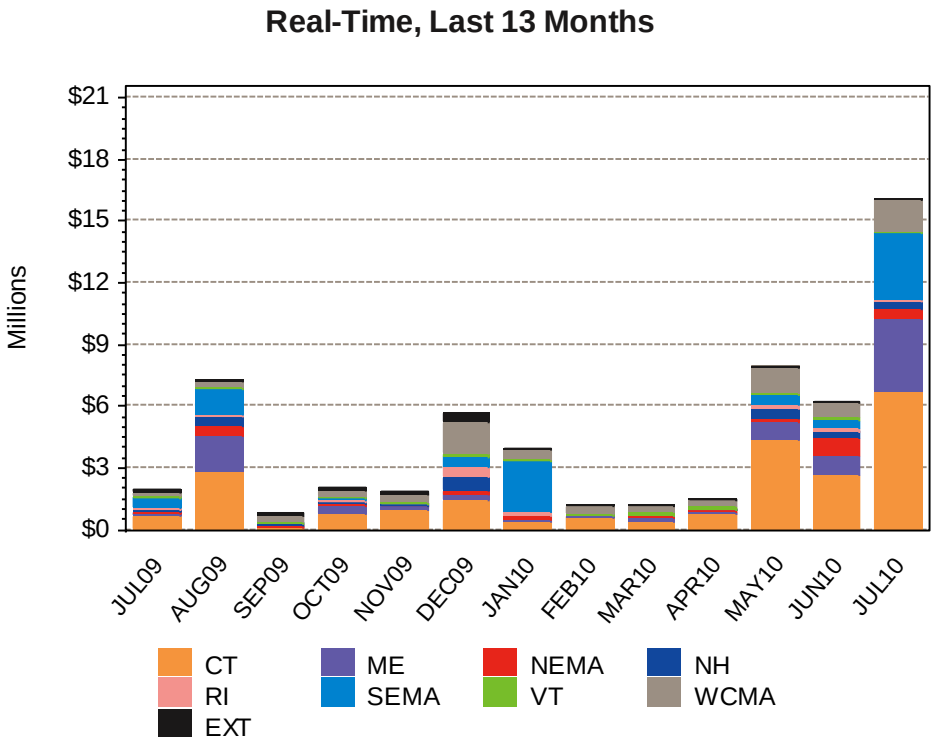


JUL-10 Real-Time Total = 16.13 M

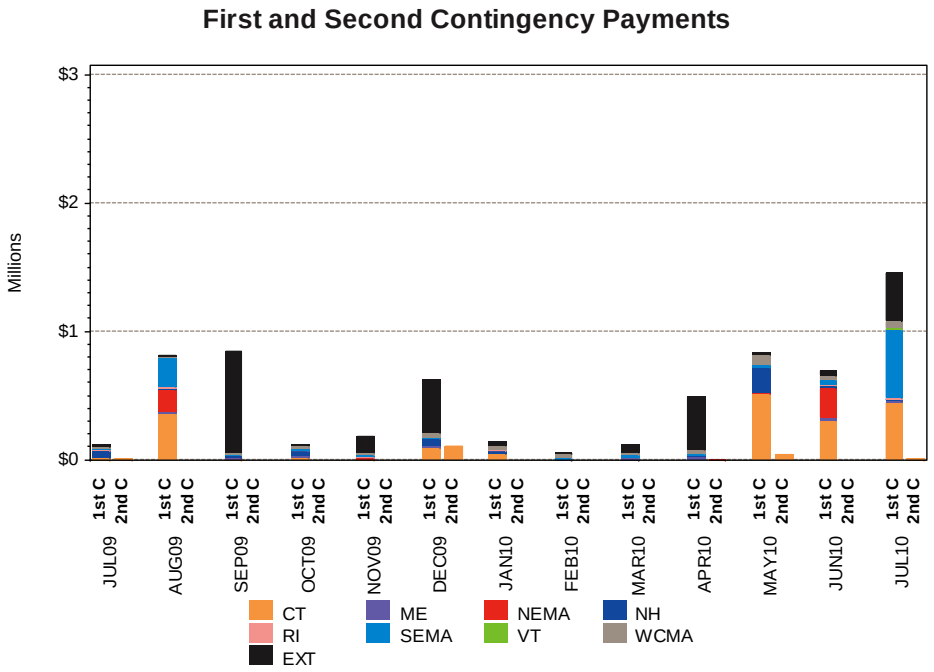


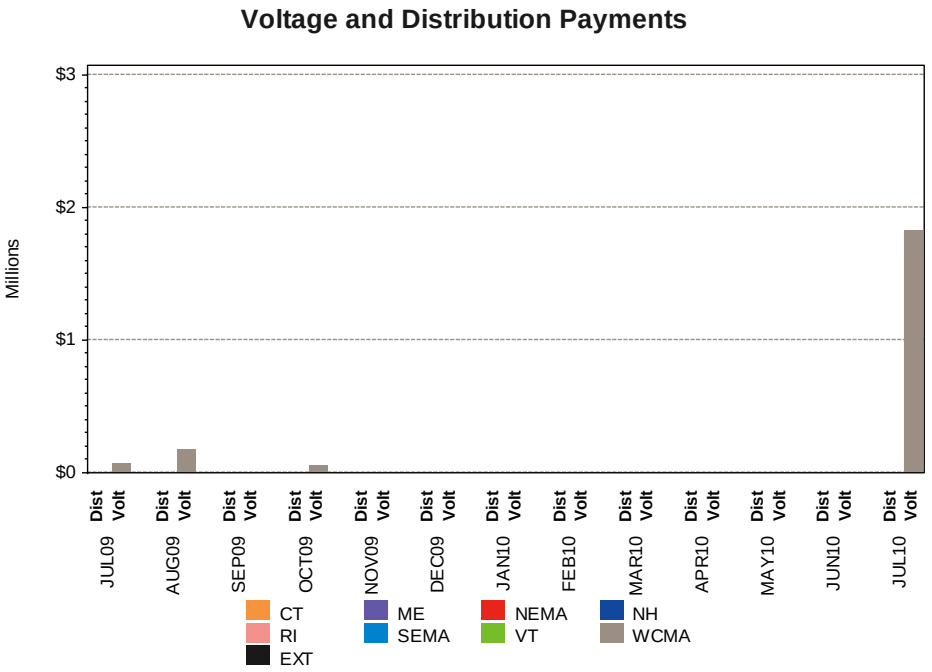
DA and RT NCPC Payments by Location, Last 13 Months



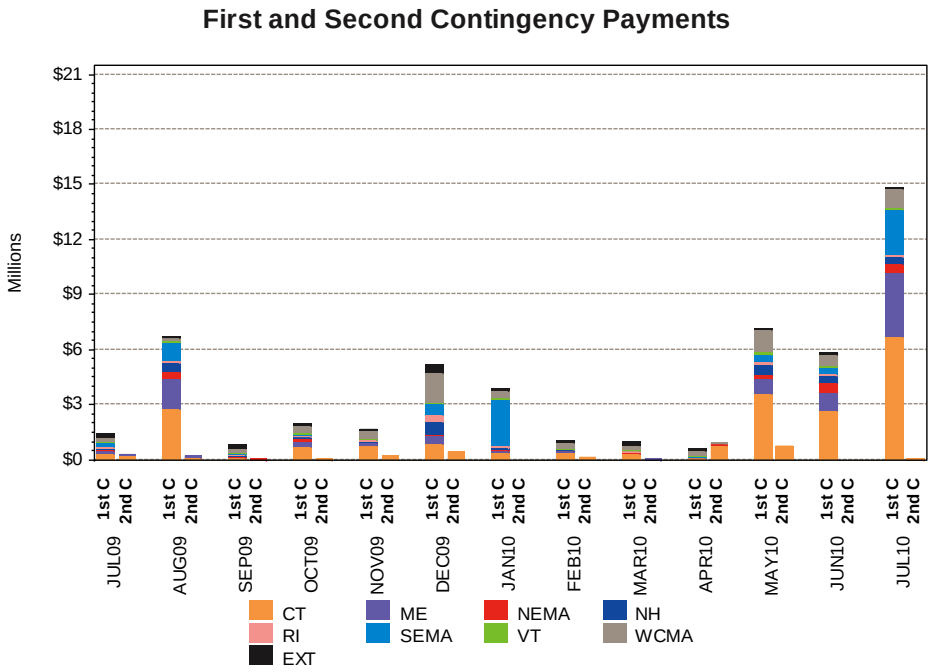


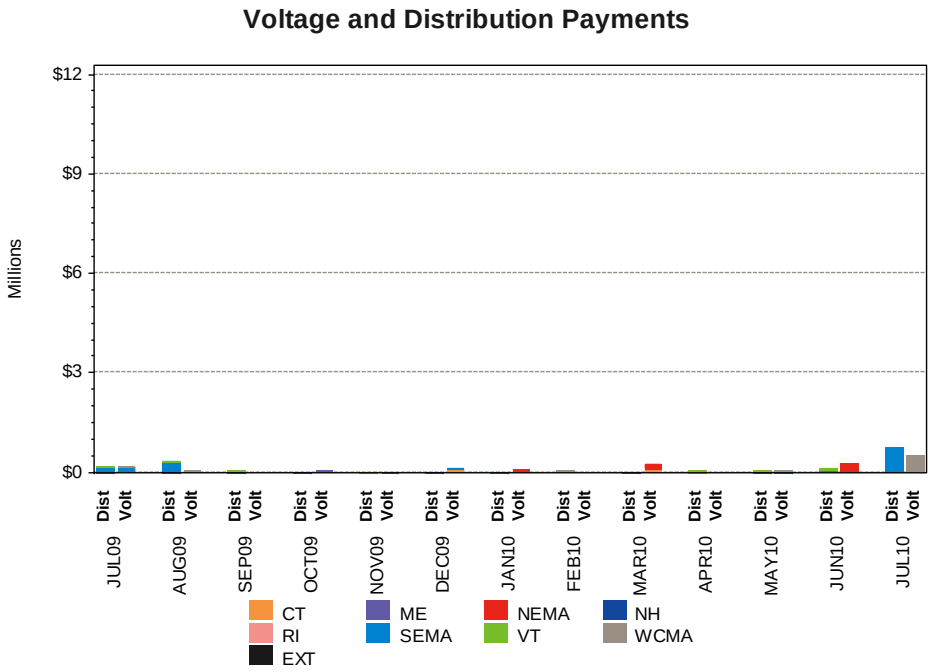
DA NCPC Payments by Type and Location



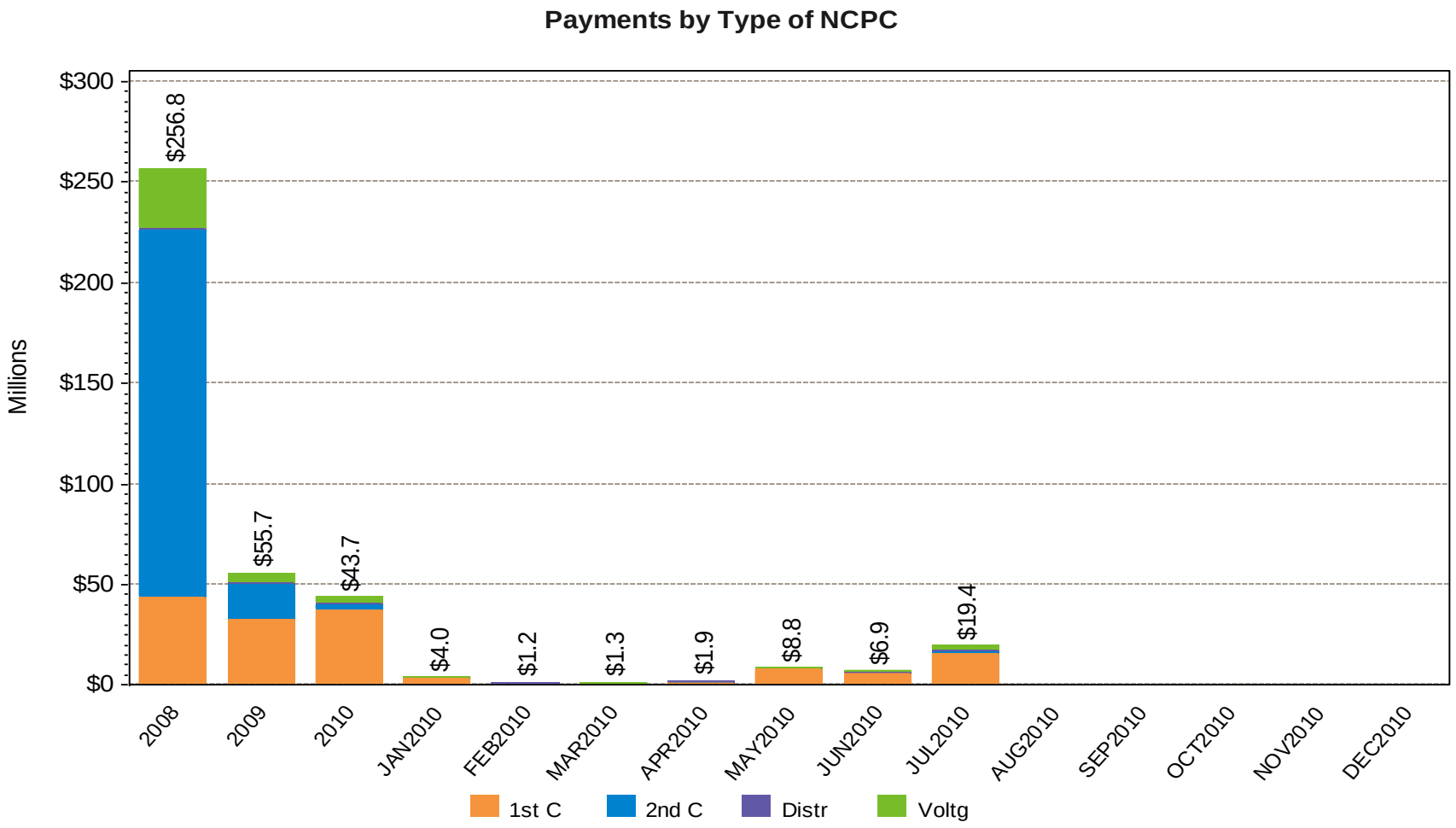


RT NCPC Payments by Type and Location

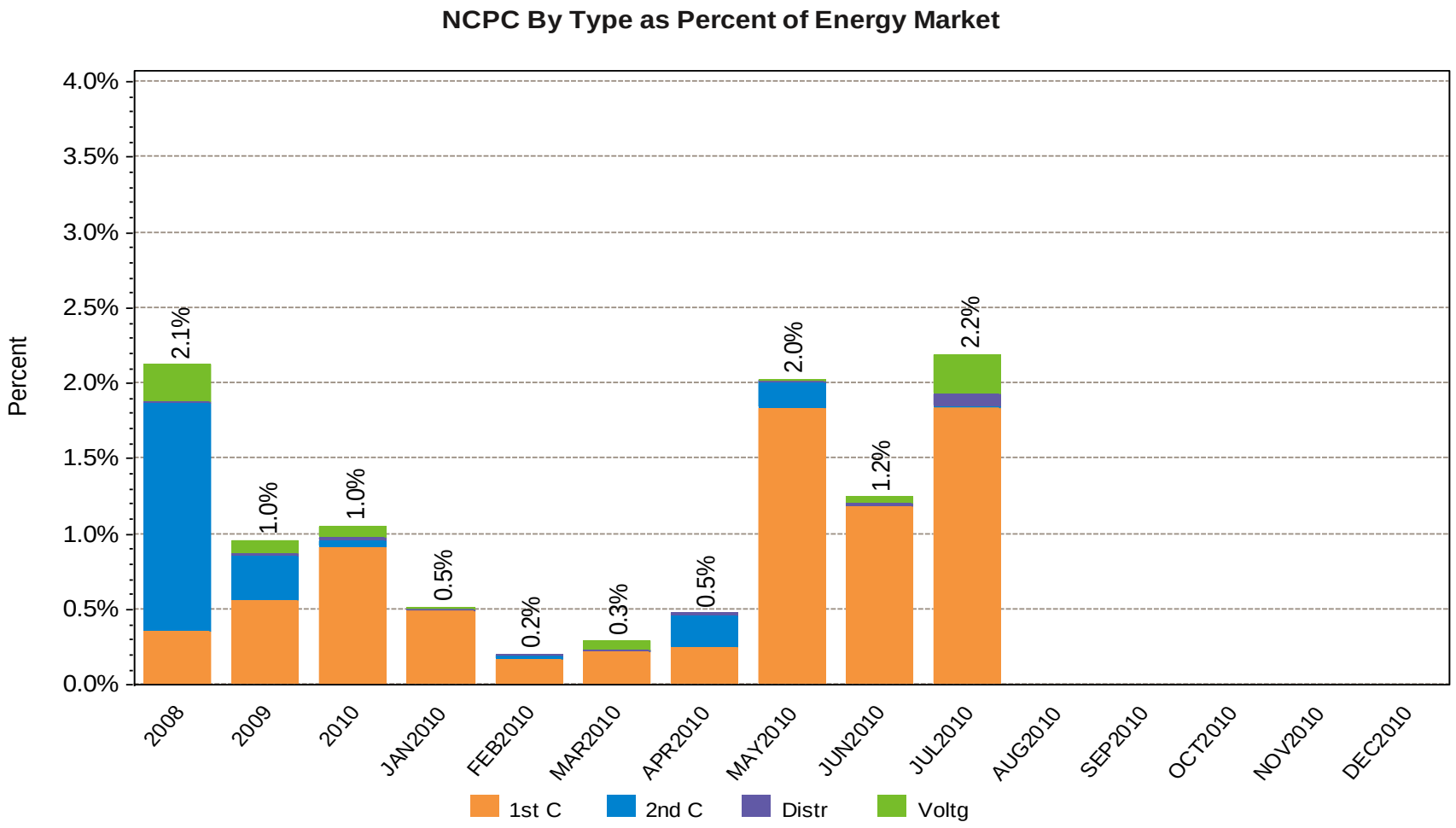




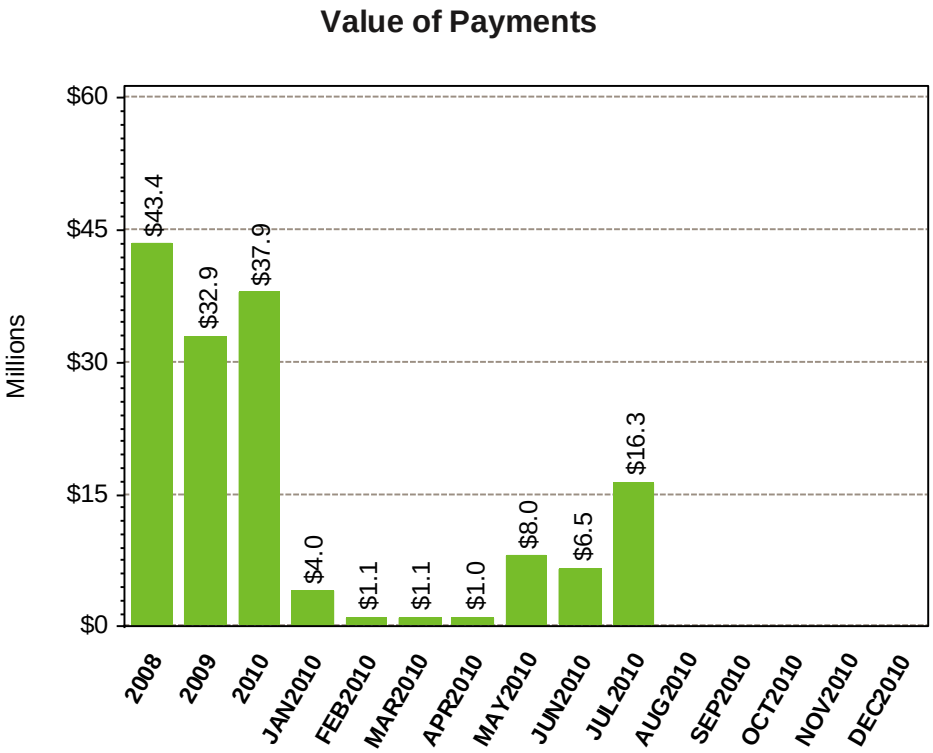
NCPC Payments by Type

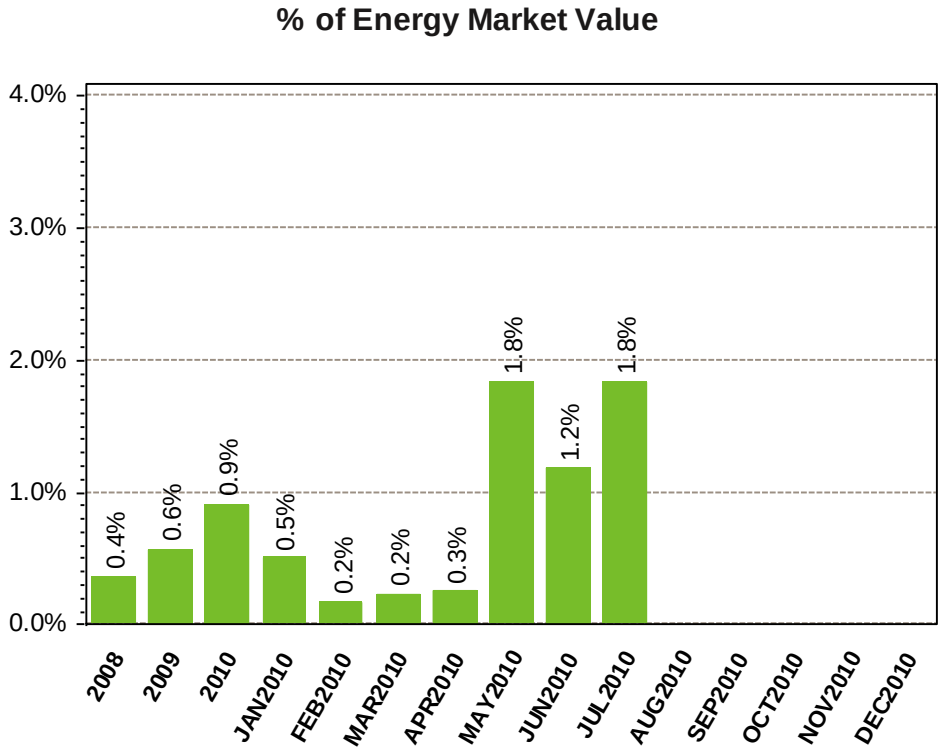


NCPC Payments by Percent of Energy Market



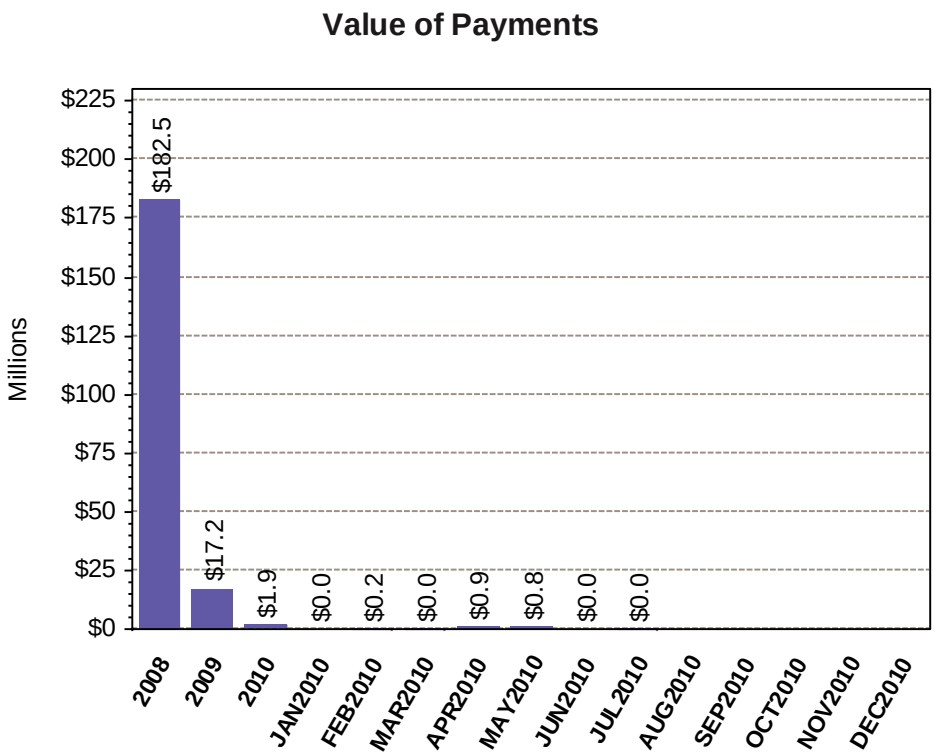
First Contingency NCPC Payments

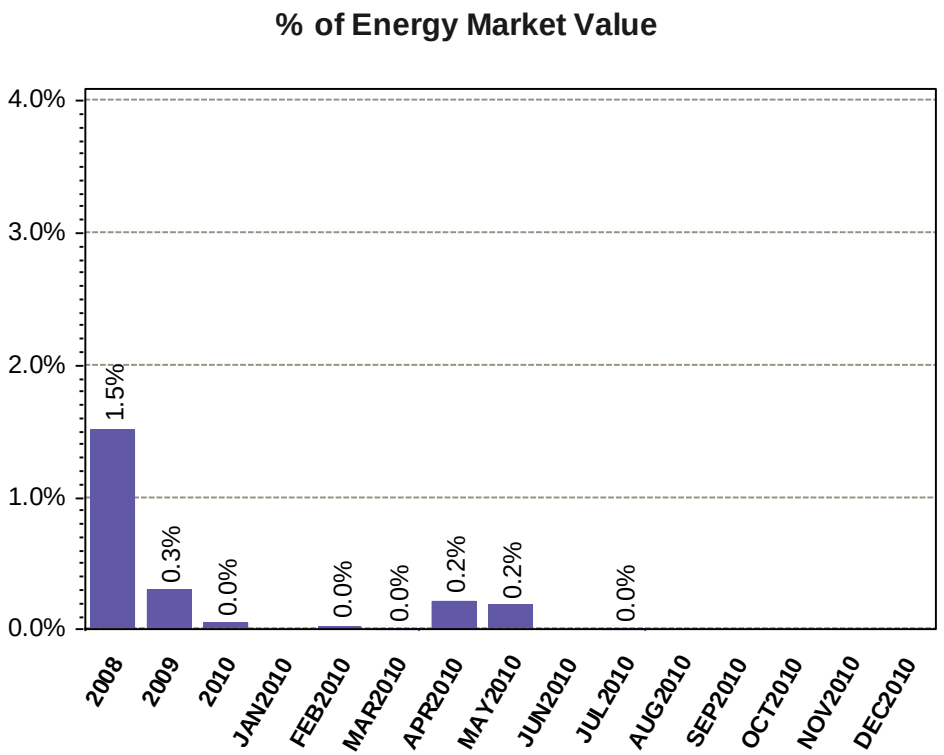




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

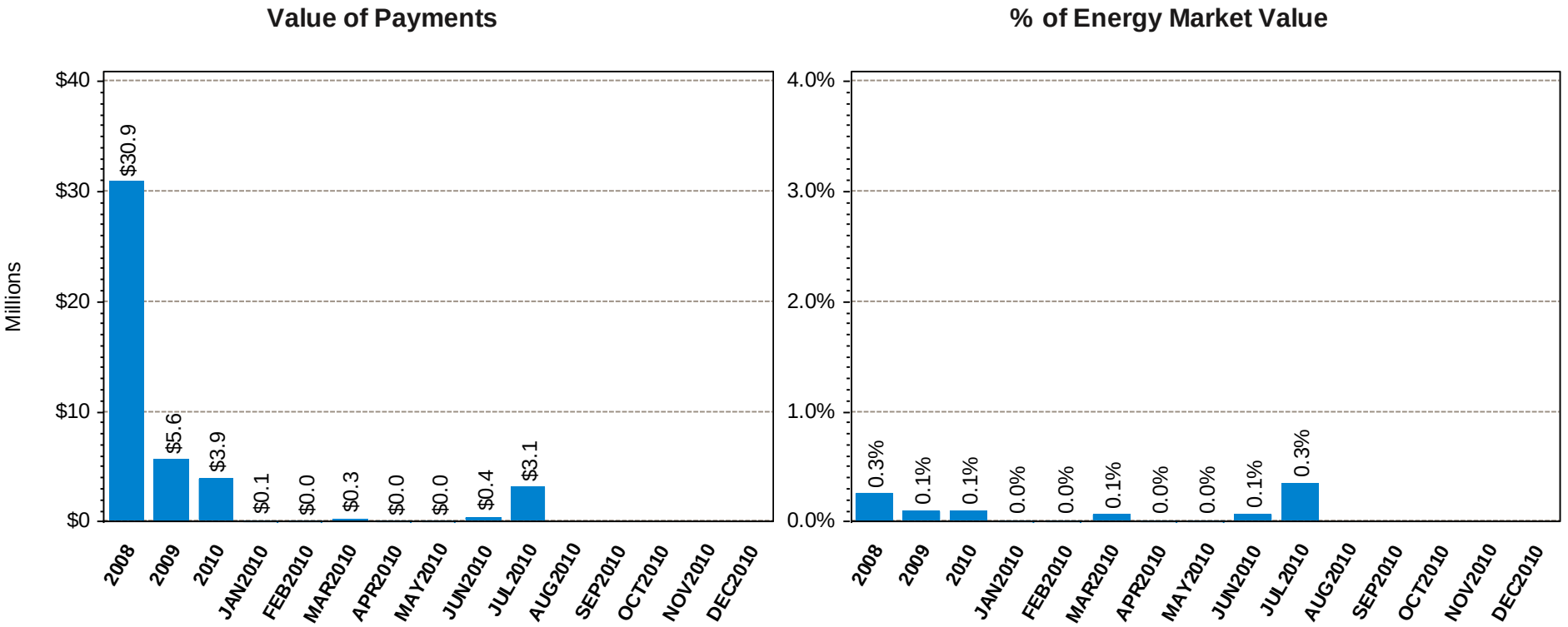
Second Contingency NCPC Payments





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

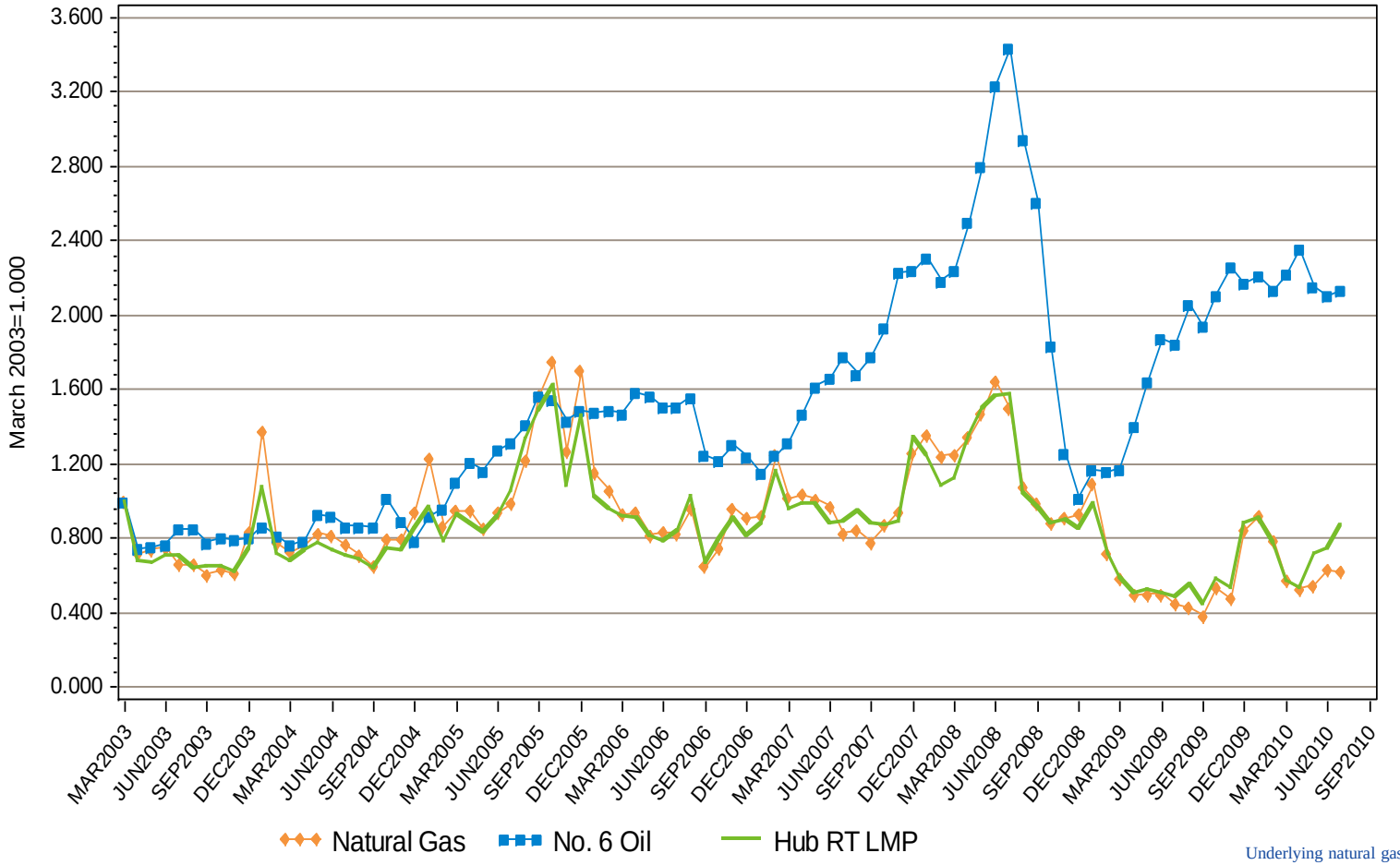
DA vs. RT LMPs ($/MWh)

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%

July-09	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$32.67	$35.43	$30.71	$32.19	$32.99	$32.63	$33.00	$33.35	$33.02
Real-Time	$33.27	$34.73	$31.24	$32.78	$33.64	$33.23	$33.62	$33.81	$33.53
RT Delta %	1.8%	-2.0%	1.7%	1.8%	2.0%	1.8%	1.9%	1.4%	1.5%
July-10	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$60.00	$63.88	$58.24	$60.32	$62.58	$60.01	$60.12	$62.33	$61.05
Real-Time	$58.99	$61.23	$56.66	$58.96	$60.82	$58.76	$59.27	$60.94	$59.72
RT Delta %	-1.7%	-4.2%	-2.7%	-2.2%	-2.8%	-2.1%	-1.4%	-2.2%	-2.2%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	83.7%	80.3%	89.6%	87.4%	89.7%	83.9%	82.2%	86.9%	84.9%
Yr over Yr RT	77.3%	76.3%	81.4%	79.9%	80.8%	76.8%	76.3%	80.2%	78.1%

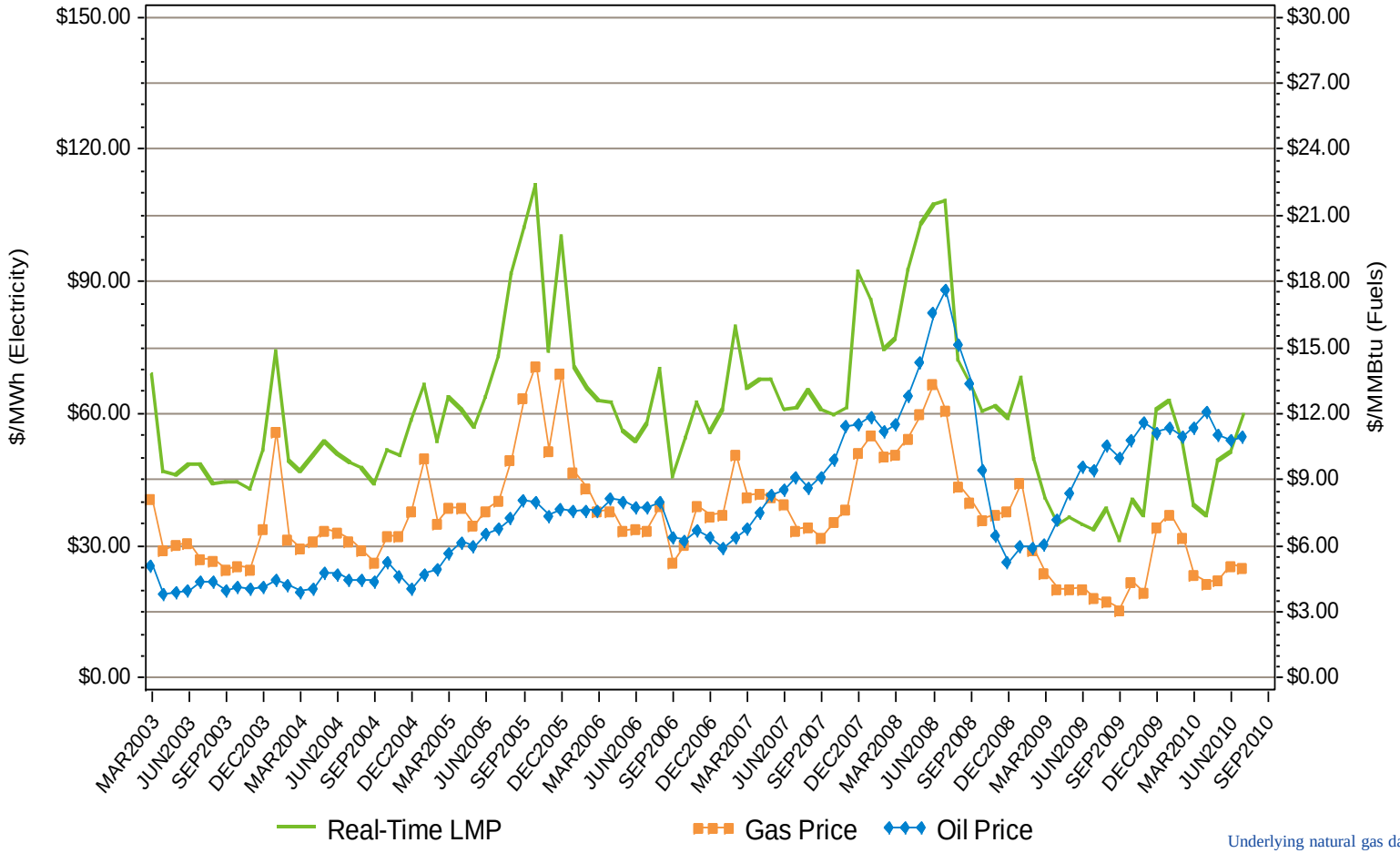
Monthly Average Fuel Price and RT Hub LMP Indexes



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:

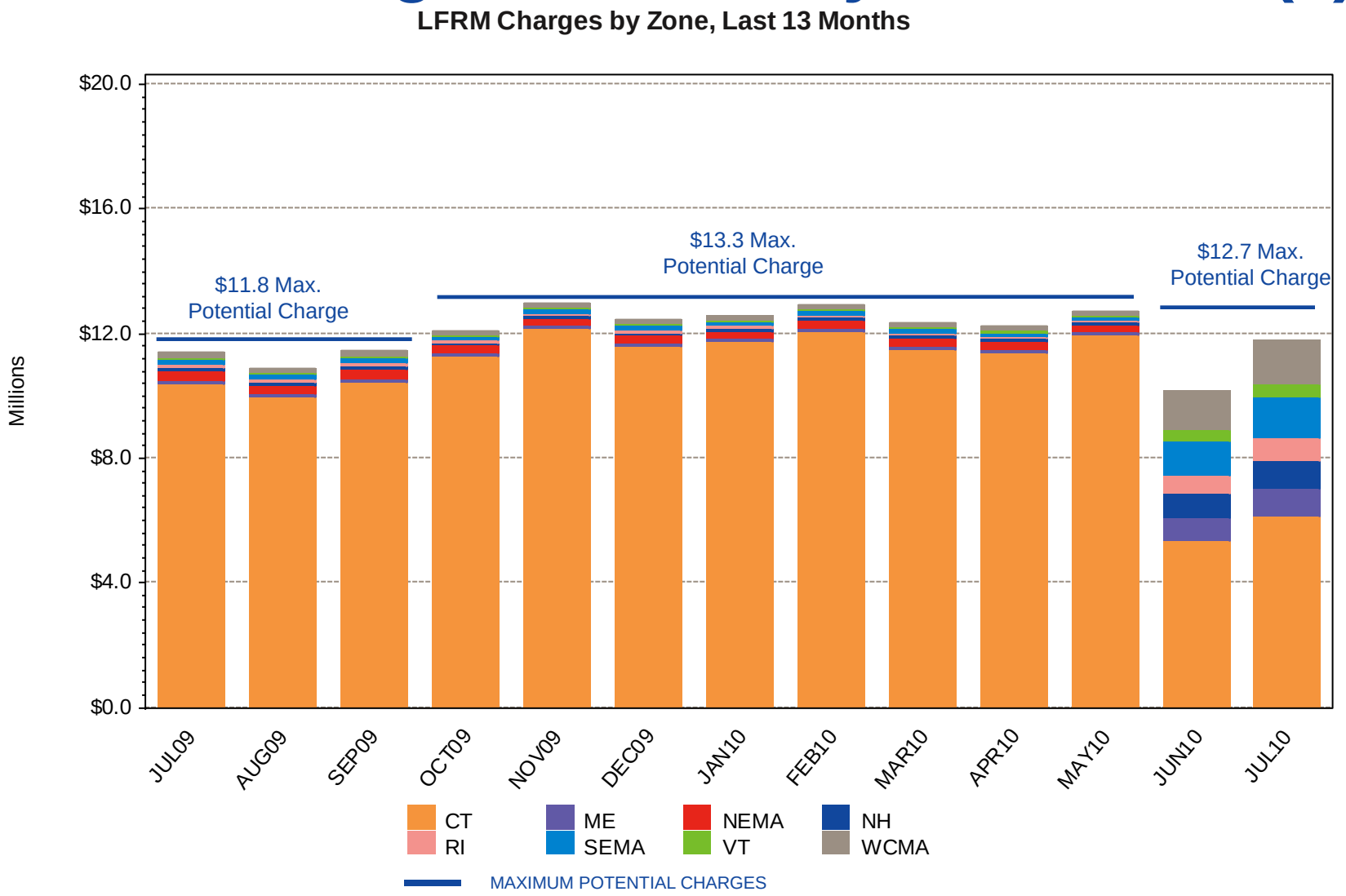
ICE Global markets in clear view

Reserve Market Results – July 2010

- Maximum potential Forward Reserve Market payments of $12.7M were reduced by credit reductions of $354K, failure-to-reserve penalties of $531K and failure-to-activate penalties of $0, resulting in a net payout of $11.8M or 93% of maximum
  - Rest of System: $1.04M/$1.16M (90%)
  - Southwest Connecticut: $3.64M/$3.78M (96%)
  - Connecticut: $7.11M/$7.74M (92%)
  - NEMA: n/a
- $1.6M in total Real-Time credits were reduced by $255K in Forward Reserve Energy Obligation Charges for a net of $1.4M in Real-Time Reserve payments
  - Rest of System: 108 hours, $922K
  - Southwest Connecticut: 108 hours, $274K
  - Connecticut: 108 hours, $138K
  - NEMA: 108 hours, $53K
- The system reserve bias factor was used on seven days (July 3, 5, 6, 9, 11, 17, 21) during this period.

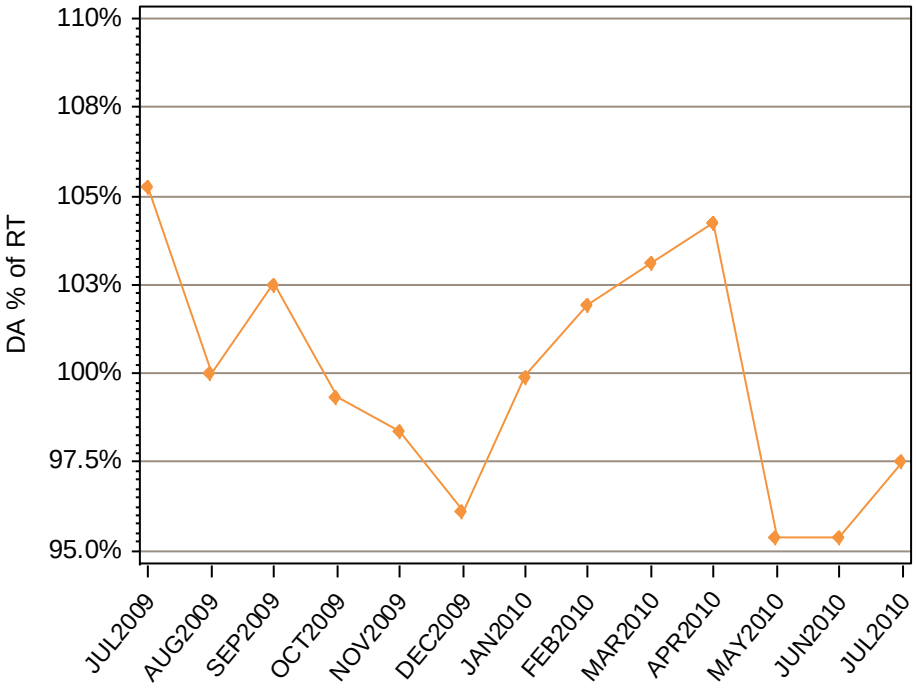
* "Failure to reserve" results in both reductions in credits and penalties in the Locational Forward Reserve Market.

LFRM Charges to Load by Load Zone ($)

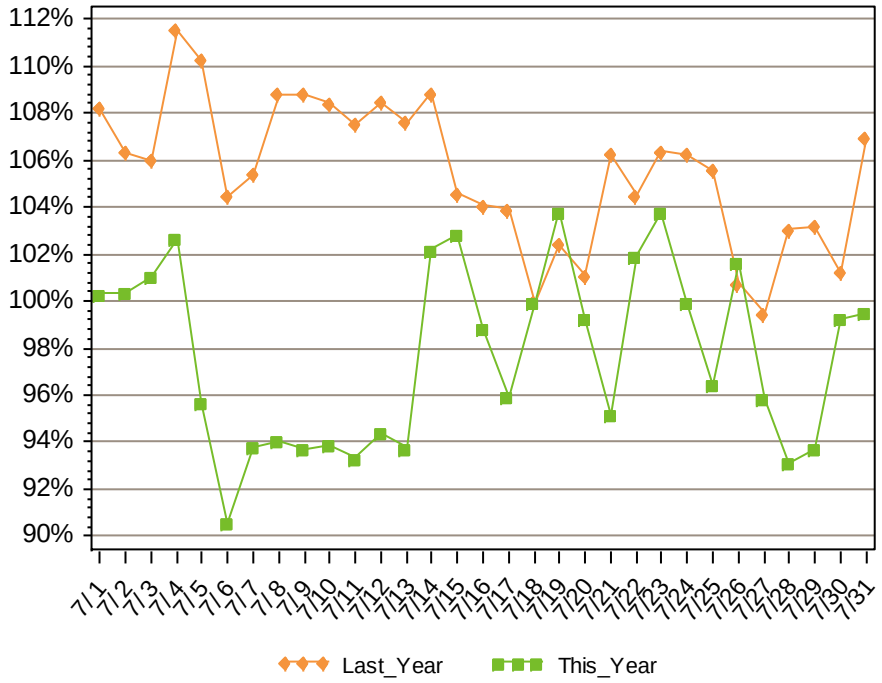


DA Load Obligation Percent of RT Load Obligation

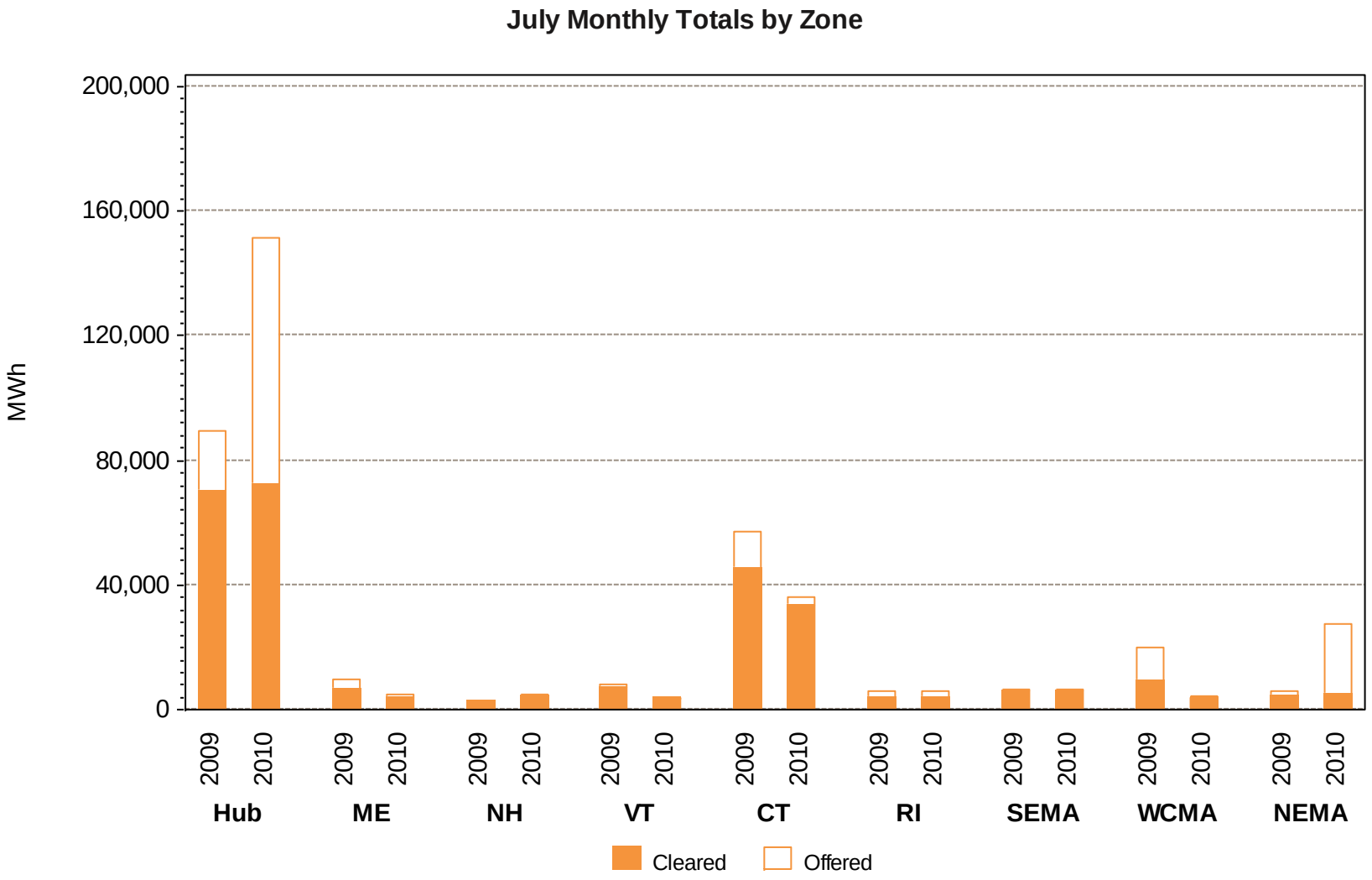
Monthly, Last 13 Months



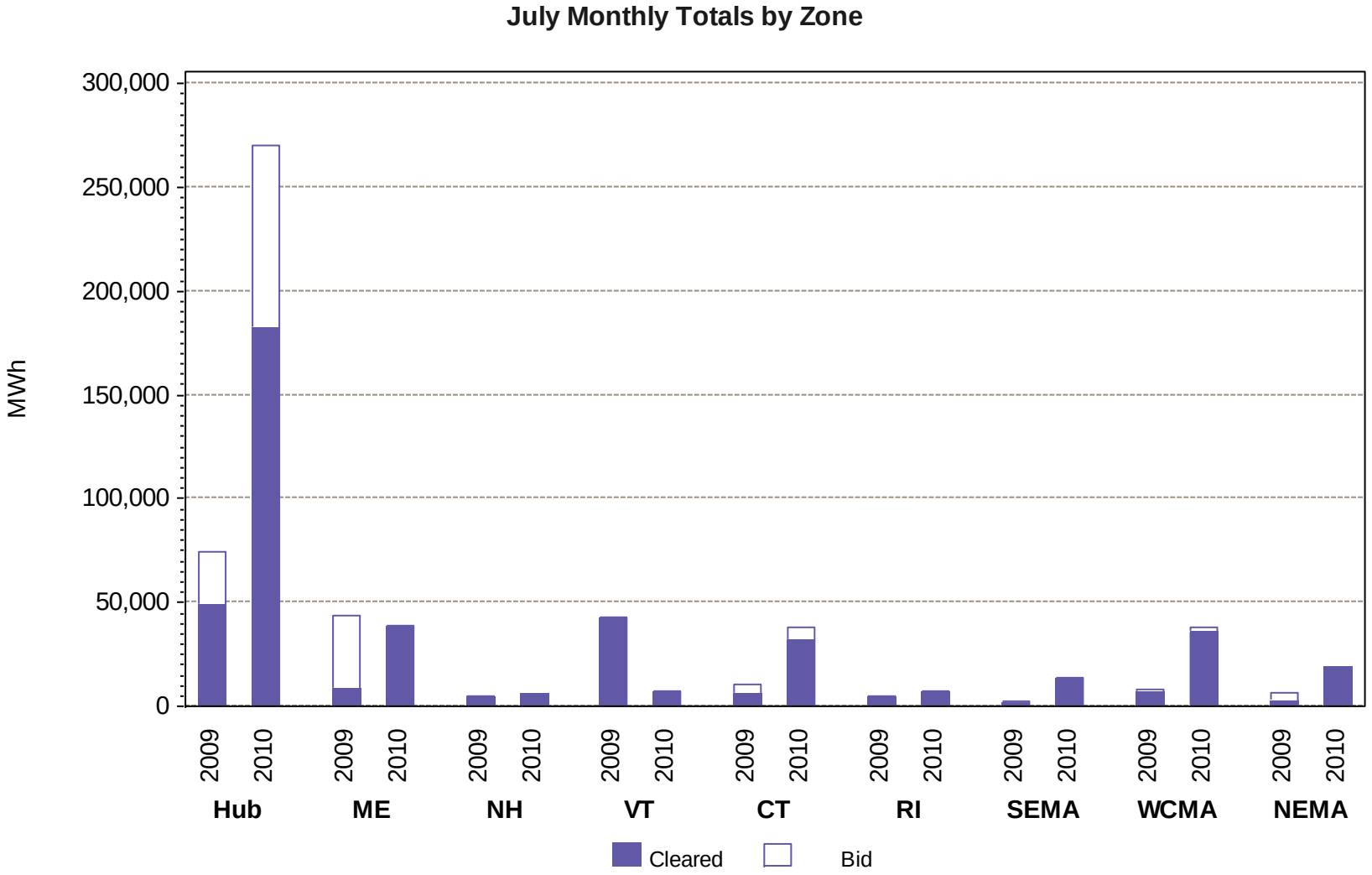
Daily, This Year vs. Last Year



Zonal Increment Offers and Cleared Amounts

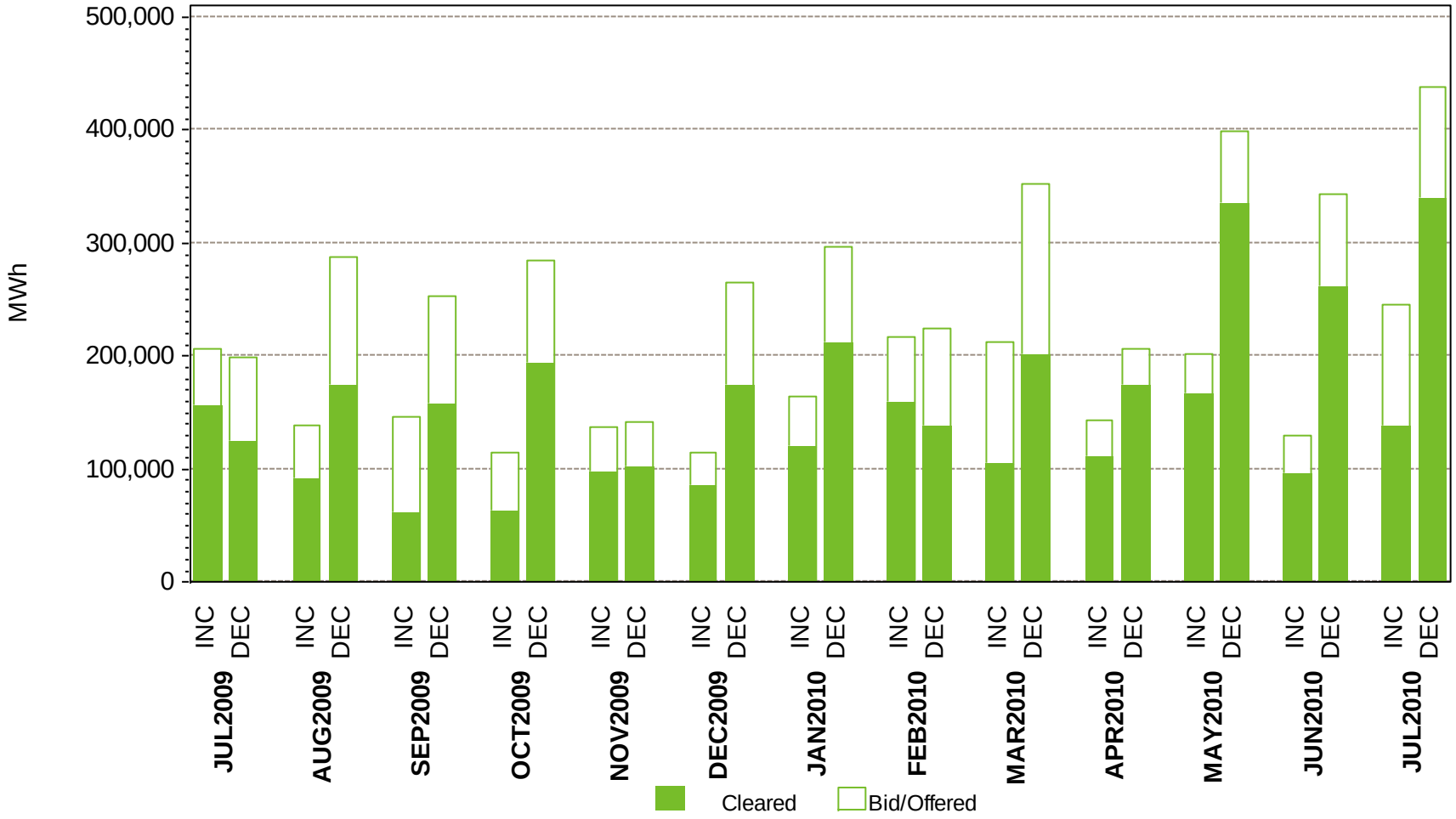


Zonal Decrement Bids and Cleared Amounts



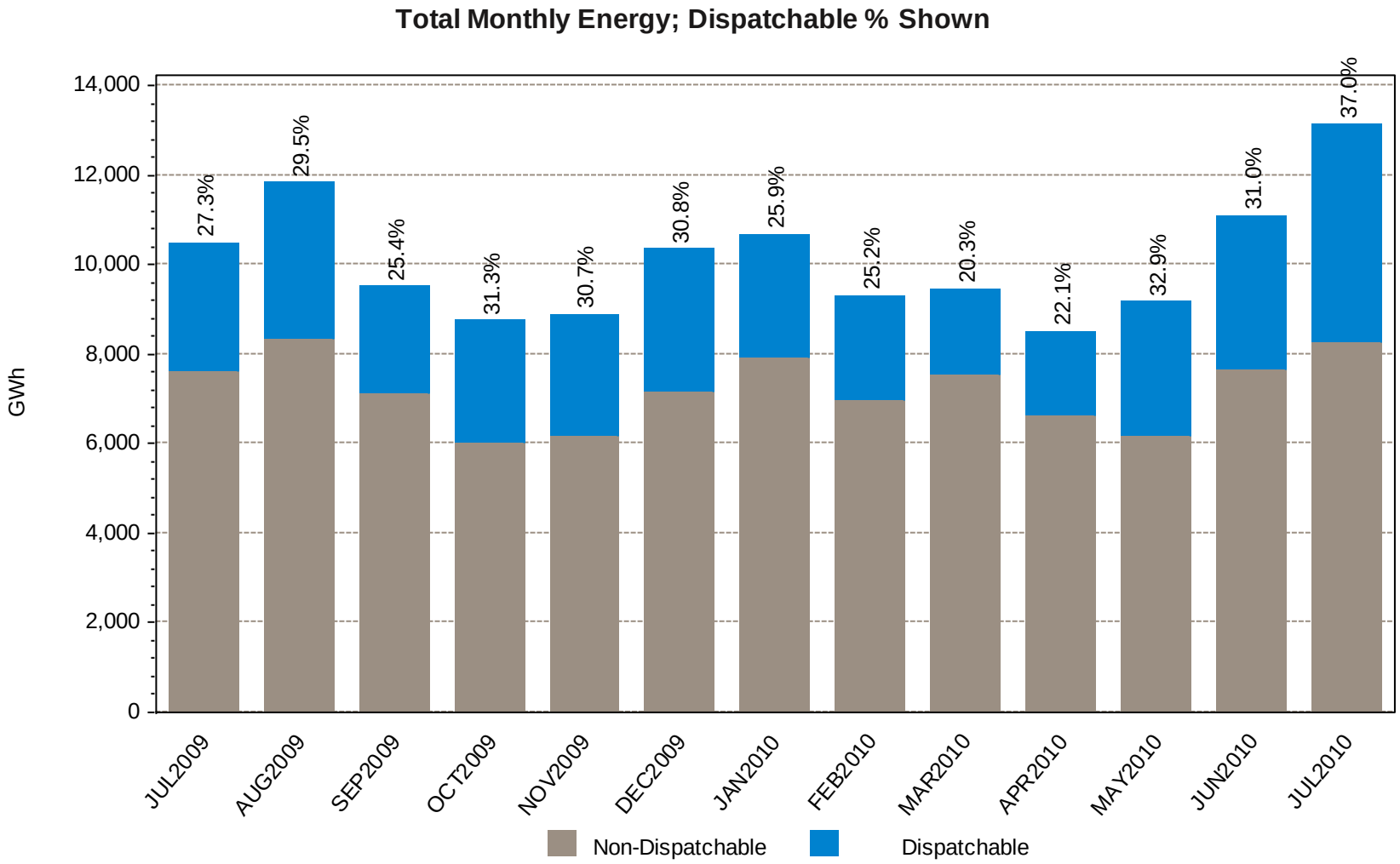
Total Increment Offers and Decrement Bids

Zonal Level, Last 13 Months

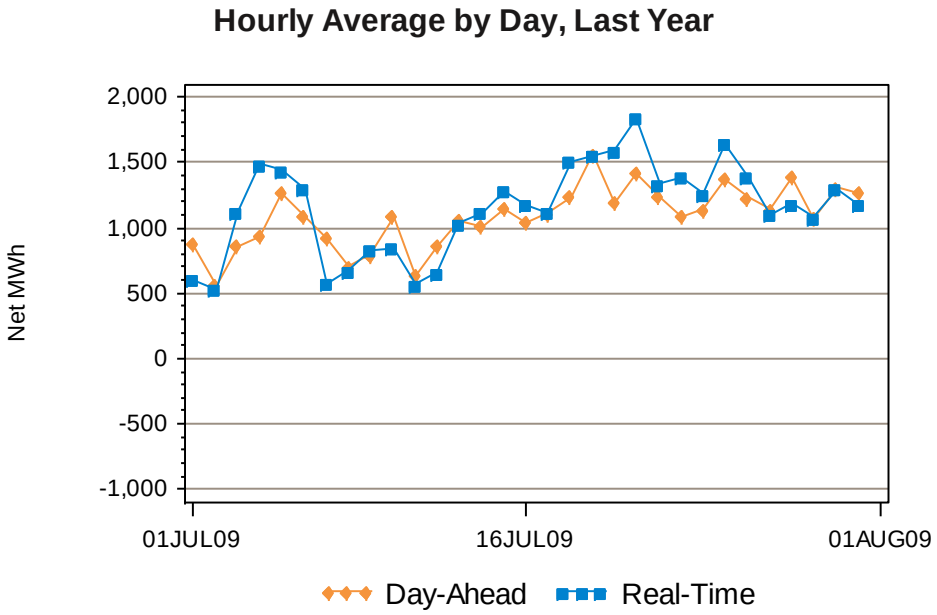


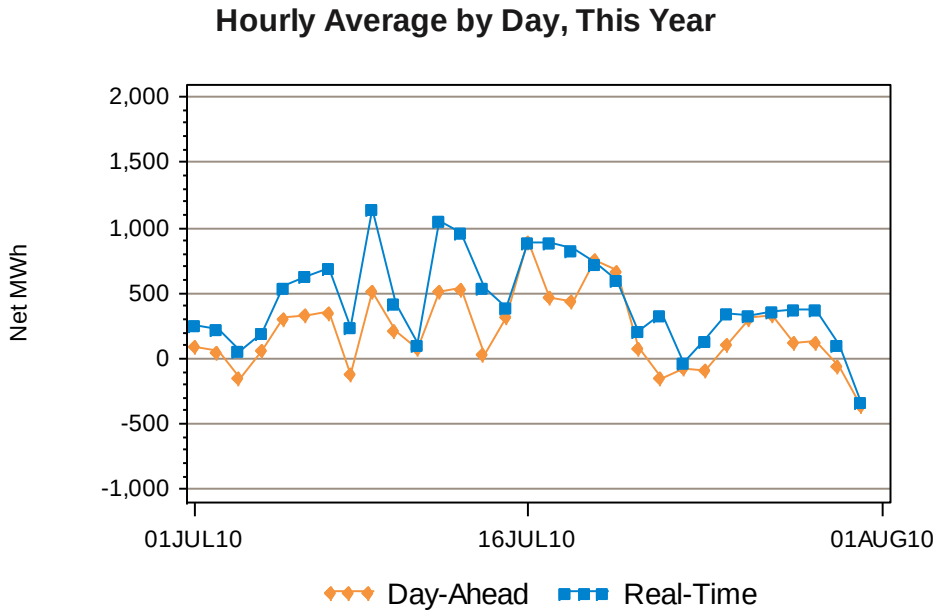
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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





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

Regional System Plan (RSP)

RSP10 Report Schedule and Process

- July 20 – Draft RSP10 Report was posted for PAC review and comment
- August 5 – by close of business, all written comments are due from PAC members to pacmatters@iso-ne.com
  - Comments must be relevant to information previously presented to PAC and not introduce new scopes of work
  - Original comments will be posted on the ISO website
  - The commenter will be made public unless ISO receives a request to keep the commentator anonymous
- August 12 – PAC discussion of written substantive comments received
  - New comments will be discussed *only as time permits*
- August 12 – PAC discussion of the NEEWS Interstate Reliability Project

RSP10 Public Meeting: September 16 Preliminary Agenda

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

Interregional Planning and Coordination

- Environmental Advisory Group (EAG) teleconference was held July 23 to discuss peak NOx emissions analysis, the draft Emissions Report, and other issues
- Inter-Area Planning Stakeholder Advisory Committee (IPSAC) WebEx is tentatively scheduled for October 6 to discuss interregional production cost studies

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 7/29/10

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 7/29/10

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

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

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

Maine Power Reliability Program (MPRP)

Status as of 7/29/10

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
- Maine PUC issued an order approving most of the projection on 6/10/10

Vermont Southern Loop Project
Status as of 7/29/10

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 7/29/10

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

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

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

Transmission Siting Update

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

Transmission Siting Update, *cont.*

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

Operable Capacity Analysis

Summer/Fall 2010 Operable Capacity Analysis (MW)

	September-10 [2] 50/50 Forecast (Reference Load)	September-10 [2] 90/10 Forecast (Extreme Load)
Generator Capacity Supply Obligation [1]	30,042	SAME
External Node Available capacity	342	SAME
Non Commercial Supply	0	SAME
Planned and other known outage MW [4]	1,540	SAME
Allowance for Unplanned Outages	2,100	SAME
Generation at Risk Due to Gas Supply	0	SAME
Net Capacity [4]	26,740	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]	(1,680)	(3,800) (-2,120)

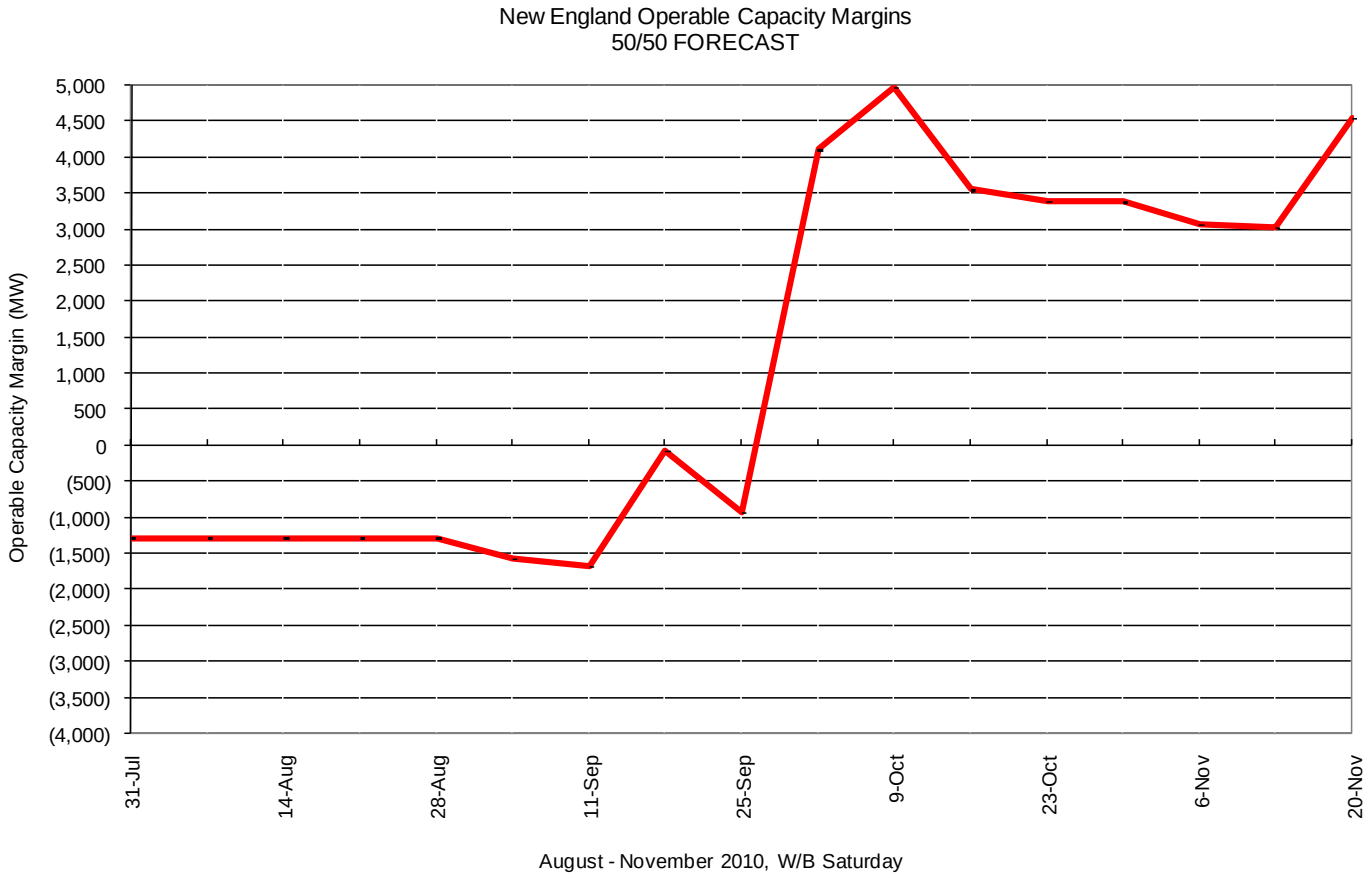
[1] Generator Capacity Supply Obligation is based on data as of July 29, 2010 and does not include Capacity Supply Obligations associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

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

[3] Rounded to the nearest hundred.

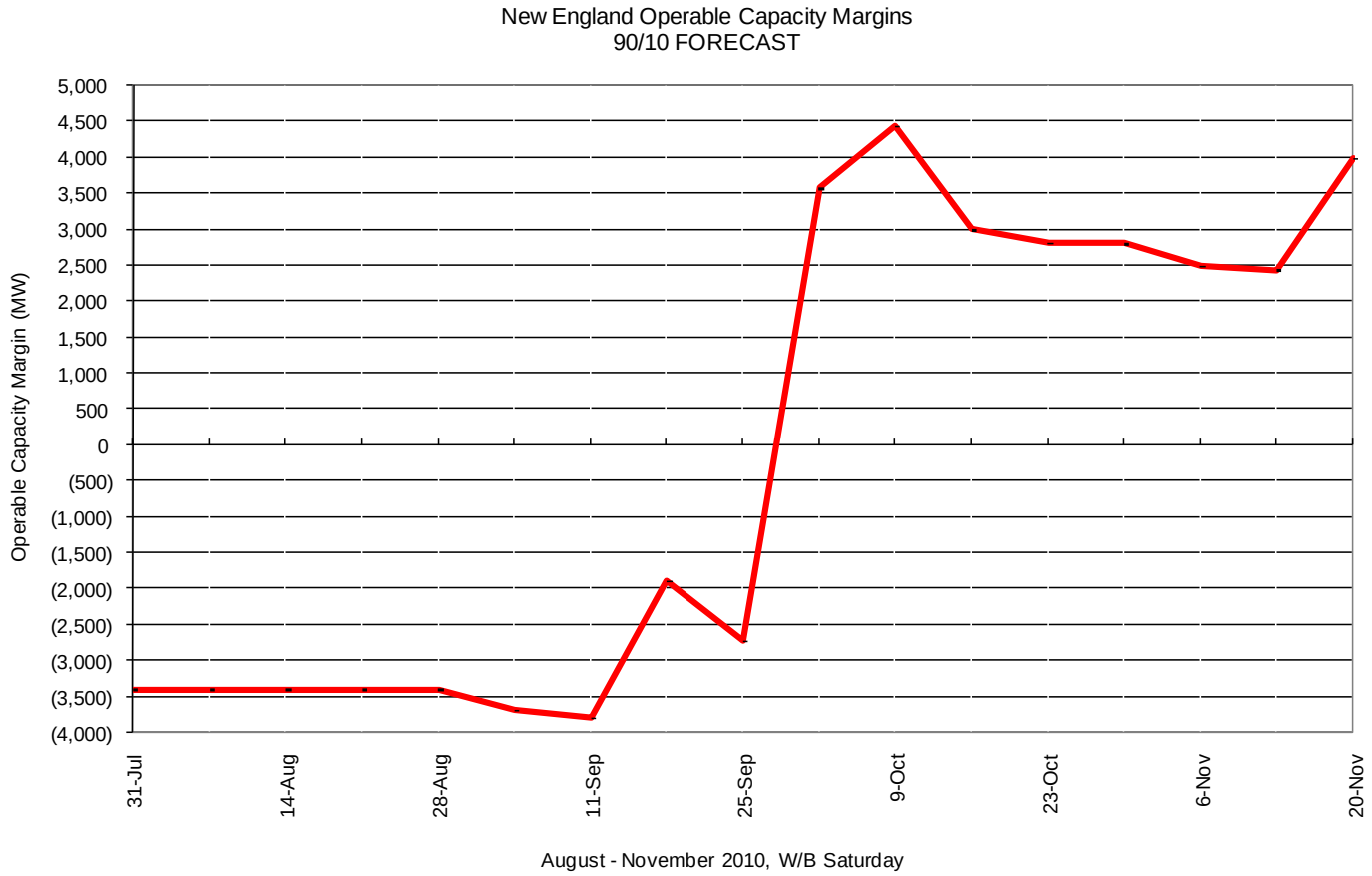
[4] Rounded to the nearest ten

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



Note: Based on data as of July 29, 2010. Does not include Settlement Only Generators and Active Demand Response.

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



Note: Based on data as of July 29, 2010. Does not include Settlement Only Generators and Active Demand Response.

Possible Relief Under OP4 based on OP4 Appendix A

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

Possible Relief Under OP4 based on OP4 Appendix A

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

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

NOTES:
1. Based on Summer Ratings. Assumes 25% of total MW Settlement Only units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are reviewed on a quarterly basis; actual available MW amounts can be viewed using the demand response dispatch software. Reserve Margin gross-ups not included and derate not applied.
4. The MW values are based on a 26,618 MW system load and the most recent voltage reduction test % achieved.

Appendix

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

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

July 30, 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 and other KNOWN 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]
07/31/2010	30,046	323	0	1,150	2,100	0	27,123	26,618	1,800	28,418	(1,290)	520	(770)	640	(130)
08/07/2010	30,046	323	0	1,150	2,100	0	27,123	26,618	1,800	28,418	(1,290)	520	(770)	640	(130)
08/14/2010	30,046	323	0	1,150	2,100	0	27,123	26,618	1,800	28,418	(1,290)	520	(770)	640	(130)
08/21/2010	30,046	323	0	1,150	2,100	0	27,123	26,618	1,800	28,418	(1,290)	520	(770)	640	(130)
08/28/2010	30,046	323	0	1,150	2,100	0	27,123	26,618	1,800	28,418	(1,290)	520	(770)	640	(130)
09/04/2010	30,042	342	0	1,440	2,100	0	26,842	26,618	1,800	28,418	(1,580)	520	(1,060)	640	(420)
09/11/2010	**30,042**	**342**	**0**	**1,540**	**2,100**	**0**	**26,742**	**26,618**	**1,800**	**28,418**	**(1,680)**	**520**	**(1,160)**	**640**	**(520)**
09/18/2010	30,042	342	0	3,840	2,100	0	24,442	22,722	1,800	24,522	(80)	520	440	640	1,080
09/25/2010	30,196	300	0	4,200	2,800	0	23,500	22,632	1,800	24,432	(930)	520	(410)	640	230
10/02/2010	30,196	300	0	5,000	2,800	0	22,700	16,793	1,800	18,593	4,110	520	4,630	640	5,270
10/09/2010	30,196	300	0	4,100	2,800	0	23,600	16,829	1,800	18,629	4,970	520	5,490	640	6,130
10/16/2010	30,196	300	0	4,600	2,800	0	23,100	17,748	1,800	19,548	3,550	520	4,070	640	4,710
10/23/2010	30,196	300	0	4,400	2,800	0	23,300	18,110	1,800	19,910	3,390	520	3,910	640	400
10/30/2010	30,196	300	0	3,400	3,600	0	23,500	18,315	1,800	20,115	3,380	520	3,900	640	400
11/06/2010	30,196	300	0	3,600	3,600	0	23,300	18,430	1,800	20,230	3,070	520	3,590	640	400
11/13/2010	30,196	300	0	3,300	3,600	0	23,600	18,772	1,800	20,572	3,030	520	3,550	640	400
11/20/2010	30,196	300	0	3,000	3,600	0	23,900	17,555	1,800	19,355	4,540	520	5,060	640	400

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. Real Time Emergency Generation is capped at 600MW.
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/Fall 2010 Operable Capacity Analysis (MW)
90/10 Forecast (Reference)

ISO-NE 2010 OPERABLE CAPACITY ANALYSIS

July 30, 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 and other KNOWN 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]
07/31/2010	30,046	323	0	1,150	2,100	0	27,123	28,738	1,800	30,538	(3,410)	520	(2,890)	640	(2,250)
08/07/2010	30,046	323	0	1,150	2,100	0	27,123	28,738	1,800	30,538	(3,410)	520	(2,890)	640	(2,250)
08/14/2010	30,046	323	0	1,150	2,100	0	27,123	28,738	1,800	30,538	(3,410)	520	(2,890)	640	(2,250)
08/21/2010	30,046	323	0	1,150	2,100	0	27,123	28,738	1,800	30,538	(3,410)	520	(2,890)	640	(2,250)
08/28/2010	30,046	323	0	1,150	2,100	0	27,123	28,738	1,800	30,538	(3,410)	520	(2,890)	640	(2,250)
09/04/2010	30,042	342	0	1,440	2,100	0	26,842	28,738	1,800	30,538	(3,700)	520	(3,180)	640	(2,540)
09/11/2010	**30,042**	**342**	**0**	**1,540**	**2,100**	**0**	**26,742**	**28,738**	**1,800**	**30,538**	**(3,800)**	**520**	**(3,280)**	**640**	**(2,640)**
09/18/2010	30,042	342	0	3,840	2,100	0	24,442	24,538	1,800	26,338	(1,900)	520	(1,380)	640	(740)
09/25/2010	30,196	300	0	4,200	2,800	0	23,500	24,441	1,800	26,241	(2,740)	520	(2,220)	640	(1,580)
10/02/2010	30,196	300	0	5,000	2,800	0	22,700	17,328	1,800	19,128	3,570	520	4,090	640	4,730
10/09/2010	30,196	300	0	4,100	2,800	0	23,600	17,365	1,800	19,165	4,430	520	4,950	640	5,590
10/16/2010	30,196	300	0	4,600	2,800	0	23,100	18,312	1,800	20,112	2,990	520	3,510	640	4,150
10/23/2010	30,196	300	0	4,400	2,800	0	23,300	18,685	1,800	20,485	2,810	520	3,330	640	400
10/30/2010	30,196	300	0	3,400	3,600	0	23,500	18,897	1,800	20,697	2,800	520	3,320	640	400
11/06/2010	30,196	300	0	3,600	3,600	0	23,300	19,015	1,800	20,815	2,480	520	3,000	640	400
11/13/2010	30,196	300	0	3,300	3,600	0	23,600	19,368	1,800	21,168	2,430	520	2,950	640	400
11/20/2010	30,196	300	0	3,000	3,600	0	23,900	18,112	1,800	19,912	3,990	520	4,510	640	400

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DRAFT Comments on
Transmission Planning and Cost Allocation NOPR
(Draft-- ~~7~~8/~~30~~4/10)

UNITED STATES OF AMERICA

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation by	**)**	
Transmission Owning and Operating Public Utilities	**)**	**Docket No. RM10-23-000**

COMMENTS OF THE NEW ENGLAND POWER POOL ON NOTICE OF PROPOSED RULEMAKING

The New England Power Pool ("NEPOOL") Participants Committee[1] offers these comments in response to the Commission's June 17, 2010 Notice of Proposed Rulemaking regarding transmission planning and cost allocation in the above-captioned docket (the "NOPR"). [fill in]

I. Introduction/background

► [Summarize progress New England has made in regional system planning and cost allocation. Note our activities and developments in the following]:

A. New England's Regional System Planning Process

New England has had a robust regional system planning process in place since 2000, when NEPOOL's regional transmission planning and expansion proposal was accepted by the Commission.[2] The process results in an annual Regional System Plan ("RSP") that is updated

[1] Capitalized terms used but not defined in this filing are intended to have the meanings given to such terms in the Second Restated New England Power Pool Agreement (the "Second Restated NEPOOL Agreement"), the Participants Agreement, or the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("ISO-NE Tariff").

[2] On June 28, 2000, the Commission issued an order, which, *inter alia*, accepted a comprehensive, open and transparent regional system planning process as part of the NEPOOL open access transmission tariff, which preceded the ISO-NE open access transmission tariff ("ISO-NE OATT"). *See ISO New England Inc.*, 91 FERC ¶ 61,311 at 62,076-77 (2000). When the RTO for New England was formed in 2004, ISO New England Inc. ("ISO-NE") received responsibility and authority over the regional tariff for New England, including the provisions governing regional system planning. In the order accepting the RTO arrangements for New England, the Commission accepted the regional system planning proposal contained in the ISO-NE OATT. *ISO New England Inc., et al.*, 106 FERC ¶ 61,280 (2004) (approving ISO-NE's regional system planning process in the context of the Commission's approval of ISO-NE's RTO status subject to certain requirements). As part of the "Attachment K" Order No. 890 compliance filing for New England, which was filed on December 7, 2007, jointly by ISO-NE, NEPOOL, the Participating Transmission Owners, Cross Sound Cable, LLC, the Schedule 20A Service

through a continuous cycle of needs assessments and other studies to reflect changes to the New England regional transmission system.

Since the inception of the regional transmission planning process in 2000, New England has had an active stakeholder Planning Advisory Committee (the "PAC") that works with ISO-NE and provides advice and feedback on needs analyses and the proposed projects that together comprise the RSPs. In this way, the PAC is involved on an ongoing basis with the continuous cycle of review and revision to the RSP. The PAC is open to all interested persons and has broad representation from industry participants, environmental advocates, consumer interests and various representatives of the six New England States. NEPOOL Participants actively participate in the PAC and also review proposed changes to the New England bulk power system through the NEPOOL Reliability Committee and its task forces. Working together ISO-NE and the PAC have completed nine annual regional system plans and are now engaged in finalizing Regional System Plan 2010. Individual transmission owners in New England also have integrated their local transmission planning into the regional system planning process through coordinated meetings. Through New England's regional system planning process numerous major reliability upgrades have been planned for and built throughout the New England States. These upgrades to the transmission network in New England have improved reliability and reduced congestion costs in the region.[3]

B. Interregional Planning Activities

1. Joint Inter-Area Planning Committee- Inter-Area Planning Stakeholder Advisory Committee [describe]

Providers and the Maine Electric Power Company, New England made additional refinements and improvements to the regional system planning process and moved all of the prior provisions regarding that process into Attachment K of the ISO-NE OATT. The New England Attachment K filing was accepted by the Commission, subject to further compliance filings, by order dated May 15, 2008. *ISO New England Inc.,* 123 FERC ¶ 61,161 (2008).

[3] The Department of Energy's 2009 National Electric Transmission Congestion Study (the "DOE Study") characterizes New England's regional system planning process as having "extensive stakeholder participation, including market participants and government representatives, including those from neighboring Canadian provinces." DOE Study at p. 55. The DOE Study also points in part to New England's planning process as a factor in reducing congestion in New England. The DOE Study states at p. 57: "These results reflect the steady efforts of the utilities, ISO, independent generators, regulators, legislators, energy service companies, and customers who have worked together to develop and implement a comprehensive and consistent set of policy, pricing and planning tools." The DOE Study can be accessed in draft form at the following link: http://www.congestion09.anl.gov/documents/docs/Congestion_Study_2009.pdf

2. Northeast Coordination Protocol and Northeast Coordinated System Plan [describe]

3. Coordination Agreements with neighboring control areas [describe]

4. NPCC and its Task Forces [Canadian involvement]

C. Cost Allocation

1. New England's intraregional cost allocation method [describe] and related transmission development [cite to DOE Study regarding success of cost allocation method]

2. New England's history of developing and allocating costs of interregional projects: (Phase II; 2nd NB Tie; [Highgate, (1st NB tie [broad 25year back-up support]); 1385 Cable replacement with NY; [add CSC as Merchant]

D. New England States Involvement [describe]

1. NESCOE/NECPUC

2. NICE

E. New England's Active Involvement in EIPC [describe]

II. Comments on the Proposed Rule

[Overview statement to the effect that what we have developed in New England for regional system planning and cost allocation works well, results in getting needed transmission built, would meet the spirit and much of the letter of the proposed rules in the NOPR and continues to improve. Regions such as New England should be given maximum flexibility to receive the benefits of well developed transmission planning and cost allocation rules and to continue to develop rules that carry out the objectives and policy goals reflected in the NOPR.]

A. Requirements related to a transmission provider's participation in regional planning process that results in a regional transmission plan

The proposed rule would require each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan that meets the transmission planning principles established in Order No. 890.

NEPOOL agrees with this proposal. The right transmission infrastructure is fundamental to maintaining reliability, enabling efficient, organized electricity markets and achieving state and federal policy goals, including renewable generation and clean energy objectives. Getting the transmission infrastructure right requires comprehensive planning on at least a regional level.

Participation in that regional planning process with a resulting regional plan that complies with Order No. 890 planning principles should not be optional.

New England already has a regional planning process and related rules in place that would fully comply with this requirement. [expand- see background section above]

B. Requirements related to taking into account/considering state and federal public policy requirements in regional transmission plans

The proposed rule would require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of public policy requirements established by state or federal laws or regulations that may impact regional transmission needs.

NEPOOL agrees that public policy requirements established by state and federal laws should be "taken into account" or "considered" by transmission providers in developing their regional plans, but this proposed rule should be qualified in certain ways, including the following:

(i) There should be a strong and clearly identifiable nexus between such public policy requirements and ~~their impact on~~ the regional transmission grid before such public policy requirements result in the planning and expansion of regional transmission.[4]

(ii) The Commission should allow each region the ability and flexibility to determine how potential transmission upgrades related to public policy requirements are identified and what the implications are once they are identified, *including whether any requirement to build the upgrades should result from such identification*. Given the shifting nature of public policy requirements, the Commission should be especially willing to provide this flexibility and should expect that this process of identifying public policy requirements and connecting them to the regional transmission plan will need to evolve and be refined over time. Additionally, the Commission should give considerable deference to the States with regard to how they want their public policy requirements considered in the context of regional transmission planning.

(iii) Any transmission expansion projects that are built based on public policy requirements may require a more focused analysis of costs/benefits than reliability upgrades. Each region should be allowed considerable flexibility to develop and implement such an analysis and the related cost allocation method. Two examples can illustrate this issue for a multi-state region such as New England. First, a single state might enact laws for the undergrounding of transmission beyond what might be required under a reliability or good utility practice standard, resulting in considerably higher costs

[4] For example, a public policy requirement such as clean air legislation could be viewed as having only a very indirect nexus with transmission, while RPS requirements would have a more direct connection, and concerted legislation among multiple states in New England to promote the building of transmission to reach remote renewable generation would have an even stronger nexus.

for the installations and for consumers in the region. Second, a subset of the states within a region might wish to enter into a long-term renewable energy purchase agreement that would require transmission to be built. Each of these examples could call for a substantially different cost allocation method than the method that is used in the normal course for reliability related upgrades to the regional transmission system. The cost allocation rules proposed in the NOPR seem to allow for this flexibility, which NEPOOL urges the Commission to retain in the final rule.

(iv) In regions with multiple States, such as New England, the States involvement in the process of identifying public policy requirements, and any related transmission upgrades and cost allocation will be especially important. Where the States have a mechanism for providing their collective input into the impact of State public policy requirements on the regional system planning process, and have formally expressed their collective input through that mechanism, the Commission should give that input considerable deference in any related matters regarding regional planning or cost allocation that come before the Commission.[5]

(v) The Commission and transmission providers in implementing this proposed rule should exercise care to avoid undue discrimination in the markets against one type of resource developer or technologies versus other types of developers or technologies based on state or federal policies. The Commission and regions such as New England have invested much time, effort and resources into developing competitive wholesale markets and the rules related to those markets, such as tariff provisions for generator interconnections. Those markets should not be undone indirectly through the implementation of other public policies in the regional system planning process. Regions with well developed, organized electricity markets, such as New England, should be given maximum flexibility in the final rule to take into account public policy requirements within the context of their electricity markets. For example, New England went through an extensive stakeholder process to develop and successfully implement rules that integrate its generator interconnection queue with its Forward Capacity Market. Market rights attach to interconnection space on the transmission grid.[6] New England would want the flexibility to preserve its system of market rights and obligations related to the interconnection of market resources within the context of taking into account public policy requirements in the Regional System Plan.

While the ISO-NE Tariff does not have express language requiring that relevant public policy requirements be taken into account in the development of the Regional System Plan, such requirements are considered in the planning process. [elaborate]

► **3. <u>Requirement of equal opportunity of nonincumbent transmission developers to develop projects identified in the regional transmission plan</u>**

[5] [Point to NECPUC/NESCOE]

[6] [Cite FCM/Queue rules.]

The proposed rule is designed to eliminate obstacles in tariffs that prevent nonincumbent transmission project developers from participating in regional transmission planning processes, thereby potentially inhibiting the development of beneficial transmission projects. The proposed rule would, among other things, require removal from a transmission provider's OATT or agreements subject to the Commission's jurisdiction provisions that establish a federal right of first refusal for an incumbent transmission provider.

NEPOOL does not have a position on the proposed rule regarding whether nonincumbent transmission developers should be given an equal right with incumbents to develop transmission projects identified in the RSP that are located within the electric system of incumbent transmission providers. NEPOOL notes that Section 1.1(b) of Schedule 3.09(a) of the Transmission Operating Agreement between ISO-NE and the Participating Transmission Owners ("PTOs") currently provides the following right to incumbent transmission providers:

> (b) Each PTO subject to the obligation to build New Transmission Facilities and Transmission Upgrades under Section 1.1(a), shall have the right to own and construct (or cause to be constructed) any New Transmission Facility or Transmission Upgrade located within or connected to its existing electric system which is included in the ISO System Plan, other than a Merchant Transmission Facility. This right shall not affect any rights that an entity may have to construct a Merchant Transmission Facility in response to a need identified by the ISO in the ISO Planning Process.

To the extent that nonincumbents transmission developers are given the rights contemplated in the NOPR, they should also have an obligation to participate in comprehensive transmission ~~solutions~~solution determinations as part of the regional transmission planning process to ensure the coordinated and coherent development of regional transmission facilities. Additionally, nonincumbents should be required to meet the same eligibility criteria as incumbents regarding reliability, financial integrity, technical expertise and the ability and obligation to build.[7]

In its discussion of nonincumbent developers, the NOPR proposes to require that all transmission project proposals to be considered in a given transmission planning cycle be submitted on a single, specified date. NEPOOL urges the Commission not to adopt this requirement in the final rule. Currently, New England does not have such a requirement, but instead the planning process is continuous and dynamic, with projects being brought forward in response to identified needs when those needs are identified. Setting up a specified date for all proposed projects to come forward could result in information being withheld from the planning process and needs not being addressed in a timely fashion. If the Commission decides to adopt this rule, it should allow regions that have a well functioning planning process, such as New England, to be exempt or obtain waiver from its application.

[7] [Cite to example of NEITC going through the process to meet eligibility criteria as an ITC under Attachment M of the ISO-NE OATT and entering into a transmission operating agreement.]

► **4. Requirement of interregional coordination of transmission planning**

The proposed rule would require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection to address transmission planning issues, especially with regard to whether alternative interregional solutions would more efficiently or effectively meet the needs identified in individual regional transmission plans. This coordination between transmission planning regions must be reflected in an interregional transmission planning agreement that can be tailored to meet the needs of the interconnected regions but that must contain certain specified elements.

NEPOOL supports the proposed rule and notes that New England is already far advanced in various interregional coordination activities through the activities of ISO-NE, the stakeholders and the States. [Cite to and describe Northeast Coordination Protocol among ISO-NE, NYISO and PJM (also takes into account each region's cost allocation rules); also note close operating relationships with neighboring regions; cite to Joint Inter-Area Planning Committee and Inter-Area Planning Stakeholder Advisory Committee; cite to New England States relationship with one another through New England States Committee on Electricity ("NESCOE") and the States relationships with neighboring regions: e.g., NESCOE and the Northeast International Committee on Energy activities]

While NEPOOL supports the proposed rule regarding interregional coordination in transmission planning, NEPOOL urges the Commission to ensure that any final rule reflects the principle that interregional projects should be identified and developed through a bottom up approach that starts with and respects each affected region's regional transmission plan. The rule should not allow for one or more regions' sponsored interregional transmission projects to be imposed on another region.

► **5. Requirement for cost allocation methods to be in place for both intraregional and interregional transmission projects that come out of the regional plan**

The Commission proposes to require that every public utility transmission provider have in place a method, or set of methods, for allocating the costs of new intraregional transmission facilities that are included in the transmission plan produced by the transmission planning process in which it participates.

NEPOOL agrees with this proposal and knows from its own successful experience that having a sound cost allocation method in place can make the difference between getting adequate transmission infrastructure built or not. The cost allocation rules in place in New England since

2004 have resulted in getting major transmission upgrades built and planned for future development, thus providing substantial reliability and congestion reduction benefits.[8]

The cost allocation rules in the ISO-NE Tariff would meet the proposed requirements of the final rule for intraregional cost allocation. [Explain how New England's intraregional cost allocation method meets each of the proposed principles for intraregional cost allocation set forth in P 164 of the NOPR.]

As the Commission recognizes in the NOPR, several different approaches to cost allocation may meet these principles and an approach such as New England's may be appropriate:

> The Commission recognizes that several approaches to cost allocation may satisfy the proposed principles. For example, a postage stamp cost allocation method may be appropriate where all customers within a specified transmission planning region are found to benefit from the use or availability of a facility or class or group of facilities (e.g., all transmission facilities at 345 kV or higher), especially if the distribution of benefits associated with a class or group of facilities is likely to vary considerably over the long depreciation life of the facilities amid changing power flows, fuel prices, population patterns, and local economic developments. Similarly, other methods that propose cost allocation to a narrower class of beneficiaries may be appropriate, provided that the method reflects an evaluation of beneficiaries and is adequately defined and supported by the transmission planning region.[9]

NEPOOL also strongly supports the flexibility the Commission proposes in allowing for different methods of cost allocation in different regions and for different types of transmission projects, on both an intraregional and interregional basis.[10] Allowing for such flexibility is especially important for those regions, such as New England, where stakeholders from multiple states have voluntarily achieved agreement on and implemented a cost allocation method that works for the region. Forcing a change to such an agreement would only tend to obstruct or delay further transmission investment. Also, as noted earlier, flexibility regarding the methods of cost allocation may be especially important for public policy related projects, which could call for a different method of cost allocation than is appropriate for reliability based projects under a cost/benefit analysis.

The proposed rule would also require that each public utility transmission provider within a transmission planning region develop a method for allocating the costs of a new interregional transmission facility between the two neighboring transmission planning regions in which the

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[8] [Cite projects/investment since inception of cost allocation method in 2004.]

[9] NOPR at P 167.

[10] NOPR at PP at 164-165 and 174-176.

facility is located or among the beneficiaries in the two neighboring transmission planning regions.

NEPOOL generally supports the proposal to require formal agreements to be in place between neighboring control areas containing cost allocation methods for interregional projects, with such methods being subject to the principles specified in P 174 of the NOPR. NEPOOL supports those principles, and particularly Principle 4, which states at P 174:

> Costs allocated for an interregional facility must be assigned only to transmission planning regions in which the facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that facility is not located. However, the interregional planning process must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if there is an agreement among the transmission providers in the regions in which the facility is located to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of the upgrades within the transmission planning regions in which the facility is located.

As noted earlier, New England has a successful history of *voluntarily* planning, developing and allocating the costs of interregional projects with its neighbors. NEPOOL would oppose a proposal that would result in involuntary imposition of costs on New England from development of facilities located outside New England. New England participants in the EIPC will be mindful of this concern as they consider Easter Interconnection-wide planning scenarios and potential cost allocation associated with such scenarios. Conversely, a potentially helpful feature to include in the final rule would be a mechanism to allow for the voluntary development of projects in one region (the host region) that are desired by market participants or other stakeholders in another region (the sponsoring region), so long as: (i) the market participants or other stakeholders in the sponsoring regionregions agree to share inon the supportsharing of the associated costs of the transmission upgrades (and receive their share of any market or transmission rights that flow from such upgrades)and benefits; and (ii) the upgrades would not cause a reliability or transmission congestion problem in the host region.[11] .

Additionally, regarding the cost/benefit analysis done for interregional projects, the final rule should recognize that just because one can show benefits to multiple regions from a transmission project does not mean there is not a less expensive way to achieve the same or similar benefits through other transmission projects built on a smaller scale or non-transmission alternatives (e.g., the build out of an extra-high-voltage transmission system from the Dakotas to the East Coast might benefit New England but New England might achieve the same or greater benefits less expensively and more efficiently through development of transmission and renewable/clean energy resources here and with neighboring control areas as part of a carefully considered regional/interregional plan tailored to this region).

[11] [possibly use example of loss of source limit for Phase II]

Finally, given the very large amounts of transmission investment that the Commission is seeking to encourage through its rulemaking, the Commission should also be mindful of how to develop such transmission in a cost efficient way. As part of its overall rulemaking regarding transmission costs and their allocation, the Commission should consider whether regional tariffs should have a mechanism, tailored for the region, that imposes a discipline on transmission project developers to accurately estimate project costs, based on the project's stage of development, and to monitor and control costs through the development cycle of the project. In ISO-NE Planning Procedure-4, New England has a mechanism that is designed in part to guard against excessive costs being put into the regional transmission rate, and to promote accurate cost estimation of projects from their inception.[~~12~~11] New England continues to work to improve transmission project cost estimation, transparency and control, and sees this subject as being closely related to cost allocation.

III. Conclusion

[~~12~~11] [Cite to Schedule 12C of OATT and PP-4]