



## FINAL AGENDA

1. To approve the preliminary minutes of the Participants Committee meetings held on June 5 and June 23-25, 2015. The draft minutes of the June 5 and June 23-25 meetings, marked to show changes from the drafts circulated with the initial notice, are included and posted with this supplemental notice.
2. To adopt and approve all actions recommended by the Technical Committees set forth on the Consent Agenda included and posted with this supplemental notice.
- 2A. To consider and take action, as appropriate, on changes to the ISO Self-Funding Tariff (Section IV of the ISO Tariff) relating to the implementation of Coordinated Transaction Scheduling. These revisions, which are contemplated by the items on the Consent Agenda, were considered without objection by the Budget & Finance Subcommittee at its May 13, 2015 meeting. Background materials and a draft resolution are included and posted with this supplemental notice.
3. To receive an ISO Chief Executive Officer Report.
4. To receive an ISO Chief Operating Officer Report.
5. To receive an ISO Internal Market Monitor summary of its 2014 Annual Report and 2015 Q1 Report. The IMM's summary presentation is included and posted with this supplemental notice. Copies of the full Reports, filed with the FERC on May 20 and June 9, 2015, respectively, are posted with the composite meeting materials.
6. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts. The Litigation Report will be circulated in advance of the meeting.
7. To receive reports from committees and subcommittees.
8. To transact such other business as may properly come before the meeting.

## **PRELIMINARY**

A meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Friday, June 5, 2015 at the Radisson Hotel Manchester Downtown, 700 Elm Street, Manchester, New Hampshire, pursuant to notice duly given. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting.

Attachment 1 identifies the members, alternates and temporary alternates attending the meeting.

Mr. Joel Gordon, Chairman, presided and Mr. Sebastian Lombardi, Acting Secretary, recorded. Mr. Gordon welcomed the members, alternates and guests who were present.

## **APPROVAL OF MINUTES OF MAY 1, 2015 MEETING**

Mr. Gordon referred the Committee to the preliminary minutes of the May 1, 2015 meeting that had been circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the May 1, 2015 meeting were unanimously approved without change.

## **CONSENT AGENDA AND OP-2 REVISIONS**

Mr. Gordon referred the Committee to the Consent Agenda circulated in advance of the meeting as well as to the memorandum and materials describing changes to Operating Procedure No. 2 (OP-2) unanimously recommended by the Reliability Committee (OP-2 Revisions) that could have been on the Consent Agenda, but for administrative reasons had been circulated separately. Mr. Gordon proposed that, absent objection, motions to approve the Consent Agenda and the OP-2 Revisions be voted together. There was no objection. Accordingly, a motion to approve the Consent Agenda and the following motion to support the OP-2 Revisions, each duly made and seconded, were unanimously approved without comment:

RESOLVED, that the Participants Committee supports the proposed OP-2 revisions recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its June 5, 2015 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

## **REPORT OF THE ISO CHIEF EXECUTIVE OFFICER**

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), began his report by sharing experiences and reflections from his recent trip to South Africa, particularly those related to that country's energy infrastructure issues and daily experiences with load shedding, which he found provided a sharp contrast and perspective to New England's experiences. He shared a copy of, and described more interesting items from, a "*Load Shedding Survival Guide – Everything You Need to Make it Through Those Dark Times*", which demonstrated in a humorous but concrete way how societies are impacted by their energy infrastructure.

Turning to the discussion paper issued and circulated to the Participants Committee earlier, entitled "*The Importance of a Performance-Based Capacity Market to Ensure Reliability as the Grid Adapts to a Renewable Energy Future*", Mr. van Welie noted the numerous comments and questions received ahead of the paper's issuance. He described the paper as a background piece addressing the interaction between energy and forward capacity markets and illustrating, based on New England's experience, how wholesale energy markets can operate in the context of significant public policy initiatives. He said that the piece could also serve as useful background for upcoming discussions at the 2015 NECPUC Symposium.

Mr. van Welie was asked whether the paper had been vetted among ISO Board members and, more generally, whether there was any sentiment among ISO-NE Board members, as had recently been expressed publicly by a PJM Board member, to facilitate mechanisms that would

ensure continued operation of nuclear resources. Mr. van Welie responded that the draft paper had not been vetted among the ISO Board because it did not contain new information, but that the paper addressed nuclear resource issues in part. He noted that the region had faced such issues with the retirement of Vermont Yankee, and would continue to face the implications of potential future nuclear plant retirements in New England, including whether such retirements could prevent the region from meeting the 2020 and 2030 U.S. Environmental Protection Agency (EPA) Clean Power Plan goals. He further highlighted the possibility that, if state initiatives result in additional renewable energy (with little to no dispatch costs), infra-marginal revenues for other resources would be lowered, pushing some resources out of the marketplace, while increasing the capacity market offers of remaining resources seeking to cover their going-forward costs. Mr. van Welie identified three ways in which the paper suggested nuclear energy producers may benefit from an increased focus on renewable energy: (i) increased capacity market revenues, with nuclear resources online most of the time; (ii) the upside of the Pay-for-Performance (PFP) mechanism; and (iii) although largely not reflected in the current market design, the valuing of low carbon emissions.

Responding to a member's question as to whether the capacity market would achieve its goals given various provisos set forth in the paper, Mr. van Welie stated that there was a very delicately balanced set of mechanisms built into the capacity market, and that compromises, such as the renewables exemption, needed to be administered carefully for the capacity market to achieve its goals. He stated that the worst case scenario for the region would be an inadequate resource revenue stream, which would push existing resources out of the market in favor of newer resources with higher costs of entry. He stated that, depending on how the issues were addressed, revenue levels in the energy and capacity markets would be impacted, and would, in

turn, influence the resulting resource mix. Mr. van Welie stated his belief that no one ~~knows~~[knew](#) what the precise technology mix would be in 10 to 20 years, and that new technology would affect the markets in unanticipated ways. He emphasized that the ISO's mission is to ensure the reliable flow of competitively ~~priced~~[priced](#) wholesale electricity, without regard to a particular resource mix. Mr. van Welie suggested that NEPOOL might wish to discuss that further and see whether there was any interest in requesting the ISO to run various scenario analyses to quantitatively determine what the technology mix could be under different assumptions. Following additional questions, Mr. van Welie reiterated that the paper was intended to be educational and not to identify all of the concerns with the New England Markets, which included market response to resource retirements, natural gas dependency and constraints, energy constraints, and seasonal operational issues.

A member, tying the issues in the paper to issues raised in connection with the 2015 requests for economic studies, asked that the ISO consider including capacity market metrics in its economic studies. Mr. van Welie explained some of the elements that made modelling capacity markets more challenging than energy markets, particularly the difficulty in predicting individual asset owner business decisions, but committed to consider the request further, including the possibility of modelling or assuming a range of outcomes.

Mr. van Welie then referred the Committee to the summary of the May 21 and 27, 2015 Board Committee meetings, which had been circulated and posted in advance of the meeting. There were no questions or comments on that ~~report~~[summary](#).

## REPORT OF THE ISO CHIEF OPERATING OFFICER

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), summarized highlights from the May COO report, which had been circulated and posted in advance of the meeting. He noted the report reflected data through May 25. He stated that in May: (i) Energy Market value was \$205 million, down \$77 million from April 2015, and down \$169 million from May 2014 (reflecting lower natural gas prices); (ii) natural gas prices were 38% lower than April 2015 average values and 50% lower than May 2014 average values; (iii) Real-Time Hub locational marginal prices (LMPs) on average were 6.9% lower than April 2015 LMPs and 31% lower than May 2014 LMPs; (iv) average (peak hour) Day-Ahead cleared physical Energy, as a percentage of forecasted load, was 99.4% in May 2015, up from 98.6% in April 2015; and (v) Net Commitment Period Compensation (NCPC) totaled \$4.2 million (2.1% of the total Energy Market value), down \$6.6 million from April 2015 and up \$289 thousand from May 2014, with \$3.1 million in first contingency payments (down \$1.4 million from April 2015), and \$1.1 million in second contingency payments (down \$5.1 million from April 2015 and almost all due to a one-day transmission maintenance outage in the NEMA area on May 12). Voltage support payments were zero, down \$64,000 from April.

Dr. Chadalavada described an event that occurred in the late afternoon on May 10, when actual peak load substantially exceeded the initial forecast of 14,700 MW for the hour ending 21:00. The weather was warmer and more humid than forecast, resulting in supplemental commitments to meet a revised evening peak load of 15,500 MW. The actual peak load exceeded the revised estimate by nearly 350 MW. Real-Time Only Energy Market External Transactions Sales were reduced beginning at 17:06. In addition, during the peak hour, a transmission line tripped, which resulted in the loss of 350 MW of generation in New

Hampshire. That loss immediately put the System into a deficiency requiring 30-Minute Reserves (and triggering Reserve Constraint Penalty Factor (RCPF) pricing) for 13 5-minute intervals, two of which also required 10-Minute Reserves. Dr. Chadalavada explained in response to a question that OP4 was not declared because the additional time and actions associated with OP4 would not have helped, with the load already decreasing.

Dr. Chadalavada clarified that the May 10 event was not a Shortage Event under the current FCM rules, but would have been under the future PFP mechanism. A member suggested that this kind of event could occur more often, particularly with tighter reserve margins. He said this outcome provided potential incentive for generators to sell off portions of their Capacity Supply Obligations (CSOs) and offer only in Real-Time, given the disparity in payments for generation committed Day-Ahead and Real-Time during such an event. He suggested this would be an undesirable outcome from operational and market perspectives. Dr. Chadalavada countered that these types of events were in fact rare and the May 10 event was the result of a confluence of factors. He stated that available data did not support the premise that such shortages would occur regularly and additional study was required before determining whether PFP would provide the proper performance incentives.

In response to another comment regarding incentives and compensation for Operating Reserves, Dr. Chadalavada opined that Operating Reserves pricing was not the key factor in shortages and he committed to further discuss the issue offline. He also remarked that load forecasting has become increasingly complicated. He explained the impact of an inaccurate forecast, including an under-estimate of 200-300 MW when cloud cover is less than estimated levels or when dew points exceed 60° Fahrenheit (hundreds of megawatts of incremental load for

each additional degree beyond forecast). He stated that ISO forecasters were receiving training in best practices to keep up with the increased difficulty.

Addressing a member's concerns that, with approximately 20 hours of scarcity built into the PFP design, events like May 10 ~~would~~ could occur more frequently, ~~and~~[which](#) would result in higher fixed costs for consumers, Dr. Chadalavada stated that the shortage estimates were very difficult to predict, and the frequency of such events factored into Participant bids might have to be re-calibrated with the benefit of experience. For more insight into the factoring of scarcity hours into FCA offers, Mr. Gordon referred members to a worksheet on the ISO website related to crafting Static De-List Bids. Dr. Chadalavada noted that, given the region's resource mix, there were limited options for additional commitment of resources in response to divergence between actual and forecasted load. With the implementation of PFP, Dr. Chadalavada hoped that options available to the ISO for the commitment of fast-start resources would increase.

## **ORDER 1000 REGIONAL COMPLIANCE CHANGES**

Mr. Donald Gates, as Chair and on behalf of the Transmission Committee, referred the Committee to the materials circulated and posted in advance of the meeting related to revisions to Sections I and II of the ISO Tariff and to the Transmission Operating Agreement (TOA) proposed and filed in response to the FERC's March 19, 2015 Order on Rehearing and Further Compliance (the March 19 Compliance & Rehearing Order) addressing the region's Order 1000 regional compliance requirements. Mr. Gates reported that the Transmission Committee at its May 26, 2015 meeting unanimously recommended these changes for Participants Committee support, with abstentions noted. Mr. Lombardi clarified that the recommended changes had

already been filed with the FERC, and any remarks and the action taken at this meeting would be reflected in comments to be submitted by NEPOOL early the following week.

Without discussion or comment, the following motion was then duly made, seconded, and approved, with an abstention noted by NextEra:

RESOLVED, that the Participants Committee supports the changes to the TOA and Sections I and II of the ISO Tariff proposed in response to FERC Order No. 1000 and the FERC's March 19 Compliance & Rehearing Order, as reflected in the materials distributed to the Participants Committee for its June 5, 2015 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

#### **RETENTION OF A CONSULTANT TO REVIEW CERTAIN ISO AUDIT RESULTS AND PROCESSES**

Mr. Steve Kirk, Chairman of the NEPOOL Audit Management Subcommittee (NAMS), referred the Committee to the materials circulated and posted in advance of the meeting seeking approval for NEPOOL to retain Mr. William (Bill) Dunn as its consultant to participate in the ongoing ISO audit process and to provide reports and recommendations regarding the same to NEPOOL through NAMS. Mr. Kirk reported that Mr. Dunn had confirmed that he could perform the scope of work approved by NAMS within the \$75,000 budget approved for this purpose by the Participants Committee in its 2015 Budget.

Without discussion, the following motion was then duly made, seconded, and approved unanimously:

RESOLVED, that (a) NEPOOL retain independent consultant, William Dunn, to review certain ISO audit results and processes and report back to the NEPOOL Audit Management Subcommittee (NAMS) regarding the same, as discussed at this meeting and upon such other terms and conditions as the Chair of NAMS and NEPOOL counsel shall determine to be appropriate; provided that the total compensation paid to Mr. Dunn shall not exceed the amount previously budgeted for this purpose, \$75,000 in total, including out-of-pocket expenses, (b) that a Consulting

Agreement with Mr. Dunn containing such terms and conditions, as determined by the Chair of this Committee or the Chair of NAMS, in consultation with the Vice-Chairs and NEPOOL counsel, is authorized and approved, and (c) that the Chair of this Committee and the Chair of NAMS are severally authorized, directed and designated to execute and deliver, on behalf of NEPOOL and the Participants, such Consulting Agreement and such other related agreements, documents and certificates as they may deem necessary or desirable.

## **ESSENTIAL POWER SLOPED ZONAL DEMAND CURVES PROPOSAL**

Ms. Allison DiGrande, Markets Committee Chair, referred the Committee to, and summarized the materials circulated and posted in advance of the meeting regarding, Essential Power's proposed Market Rule changes to implement sloped zonal demand curves in the Forward Capacity Market in time for FCA10 (the Essential Power Proposal). She reported that the Essential Power Proposal, which was presented at the Markets Committee meeting in May, was based on the ISO's earlier development of proposed sloped zonal demand curves, which had also been discussed at the Markets Committee, but deferred by the ISO in April based on reliability concerns in light of the potential new zonal boundaries that could be modeled for FCA10. The Essential Power Proposal was considered by the Markets Committee in May and there were two amendments offered by GDF Suez that were not supported by the Markets Committee. She said that the final motion to recommend Participants Committee support for the Essential Power Proposal received a 42.02% Vote by the Markets Committee so it was not recommended for approval. She stated that one of the two GDF Suez amendments regarding the clearing rule had been incorporated into the Essential Power Proposal now being presented to the Participants Committee.

The Essential Power representative then explained the background behind, and advocated for, the Essential Power Proposal. He suggested that the decision to delay implementation [of](#)

[zonal demand curves](#) had been harmful to capacity suppliers who had incurred planning and implementation costs based on the assumption that the sloped zonal demand curves would be in place for FCA10. Further delay in implementation, he opined, would waste suppliers' investments, eliminate the benefits of the system-wide sloped demand curve (e.g. stability, market power and mitigation, and reduced volatility), and reduce investor confidence and willingness to commit funds. Accordingly, Essential Power proposed implementation of sloped zonal demand curves and administrative pricing rules in FCA10 consistent with previous commitments. He added that the reliability concerns ISO had identified with the [Essential Power](#) ~~p~~P~~ro~~posal were concerns that could be addressed in the stakeholder process in the fall, allowing prior commitments to be met and benefits captured in the interim.

The following motion was then duly made and seconded:

RESOLVED, that the Participants Committee supports revisions to Market Rule 1 and Tariff Section I.2.2 to implement a capacity zone demand curves design, and related modification for reconfiguration auctions, CSO bilaterals, and auction pricing in the absence of competitive conditions, as proposed by Essential Power (as modified to include the removal of Market Rule 1 Section 13.2.3.3(g)(auction clearing rule)), and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Members expressed their views [with some](#) supporting and [others](#) opposing the ~~p~~P~~ro~~posal. Some voiced opposition to the Essential Power Proposal based on concerns that the sloped local demand curves would cause issues with reliability, particularly in the smaller zones. Others [advocated in support of the Proposal](#), identifying concerns with vertical demand curves and current administrative pricing rules, particularly with potential new zones. ~~supported the~~ ~~Proposal.~~

Following additional comments, the Committee then considered and, by a show of hands, voted and failed to approve the Essential Power Proposal.

## LITIGATION REPORT

Mr. Patrick Gerity, NEPOOL Counsel, referred the Committee to the June 4 Litigation Report that had been circulated and posted the evening before the meeting, which he indicated continued to reflect a high level of activity. He highlighted the status of the pending Forward Capacity Market proceedings, including the May 29 order accepting the ISO filing identifying two potential new boundaries for Capacity Zones for FCA10, the status of the FCA9 results pending before the FERC, the FCA8 results pending before the U.S. Court of Appeals for the D.C. Circuit, and the June 2 order issued by the FERC in the FCA1 results remand proceeding. He reported that, in the June 2 order, the FERC reversed certain prior determinations with respect to FCA1 and found that resources prevented from prorating quantity in that auction should have received the full clearing price for each megawatt offered. He explained that a briefing schedule had been established to provide the FERC with the additional information it requested in order to help it develop a more complete record and determine appropriate resettlements. In response to questions, Mr. Raymond Hepper, ISO General Counsel, indicated that the timing for the potential resettlements could not yet be predicted, and that it was likely that the ISO would propose that resettlements be charged to Regional Network Load within the affected Reliability Region.

## COMMITTEE REPORTS

The Vice-Chairs of each ~~of the~~ Technical Committees reported on the schedule for committee meetings in June, which were to include discussions at the June 16 Reliability

Committee meeting on import limits from the new zones, and at the June 18 Transmission Committee on revisions proposed in response to the FERC's May 14 order on the Order 1000 interregional compliance filings (to be subsequently considered at the Summer Meeting in Stowe). Mr. Dell Orto reported that the Budget & Finance Subcommittee meeting was scheduled to meet twice in August, ~~once~~ on August 13 following the conclusion of the Markets Committee summer meeting, and on August 26, where drafts of the 2016 ISO and NESCOE budgets would be considered. As reported earlier, NAMS would be working with Mr. Dunn and the ISO on upcoming efforts, and would schedule a meeting if and as necessary.

#### **OTHER BUSINESS**

Looking ahead on the calendar, Mr. Gordon reminded members of the NECPUC Symposium to be held June 7-9 in Newport, Rhode Island, and encouraged all those interested to attend. He reported that the next regularly-scheduled meeting of the Participants Committee would be the June 23-25, 2015 Participants Committee Summer Meeting at The StoweFlake Resort & Conference Center in Stowe, Vermont. Mr. Joseph Staszowski encouraged those interested to register for the golf tournament. Mr. Gerity addressed registration details for the Summer Meeting, and noted the information provided with respect to additional activities, places of interest and restaurants in and around Stowe.

There being no further business, the meeting adjourned at 11:36 a.m.

Respectfully submitted,

Sebastian Lombardi, Acting Secretary

MEMBERS AND ALTERNATES PARTICIPATING IN  
JUNE 5, 2015 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ashburnham Municipal Light Plant	Publicly Owned		Gary Will	
<del>Associated Industries of Massachusetts</del>	<del>End User</del>			<del>Roger Borghesani</del>
Belmont Municipal Light Department	Publicly Owned		Phil Smith	
Boylston Municipal Light Department	Publicly Owned		Gary Will	
BP Energy Company	Supplier			Nancy Chafetz ( <a href="#">tel</a> )
Brookfield Energy Marketing/Cross-Sound Cable (CSC)	Supplier	<del>Aleksandar Aleks</del> Mitreski		
Calpine Energy Services, LP	Supplier	<a href="#">John Flumerfelt</a>	Brett Kruse	
Central Maine Power Company	Transmission	Eric Stinneford (tel)	<a href="#">Sue Clary (tel)</a>	
Chester Municipal Light Department	Publicly Owned	Phil Smith		
Chicopee Municipal Lighting Plant	Publicly Owned		Gary Will	
Concord Municipal Light Plant	Publicly Owned		Phil Smith	
Conn. Municipal Electric Energy Cooperative	Publicly Owned	Brian Forshaw		
<del>Conservation Law Foundation</del> <a href="#">Conn. Office of Consumer Counsel</a>	End User	<del>Jerry Elmer</del>		<a href="#">Dave Thompson</a>
Conservation Services Group	AR		<del>Doug Hurley</del>	<a href="#">John Keene</a>
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
CPV Towantic, LLC	Generation	Daniel Pierpont ( <a href="#">tel</a> )		
Danvers Electric Division	Publicly Owned		Phil Smith	
<del>DC Energy</del>	<del>Supplier</del>	<del>Bruee Bleiweis</del>		
Dominion Energy Marketing, Inc.	Generation	Jim Davis ( <a href="#">tel</a> )		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz ( <a href="#">tel</a> )
Dynegy Marketing and Trade	Supplier		<del>Dean Ellis</del>	William Fowler
<del>Elektrisola, Inc.</del>	<del>End User</del>			<del>Dave Cavanaugh</del>
Emera Energy Companies	Transmission	Jose Rotger		<a href="#">Andrew McCullough</a> <a href="#">Sandi Hennequin</a>
Emera Maine	Transmission	Jeff Jones ( <a href="#">tel</a> )	Stacy Dimou	
Energy America, LLC	Supplier			Nancy Chafetz ( <a href="#">tel</a> )
EnerNOC, Inc.	AR	Herb Healy (tel)		
Entergy Nuclear Power Marketing LLC	Generation		<a href="#">Ken Dell Orto</a>	William Fowler
Essential Power, LLC	Generation	M.Q. Riding ( <a href="#">tel</a> )	<a href="#">William Fowler</a>	
Eversource Energy	Transmission	James Daly	Joe Staszowski ( <del>tel</del> )	
Exelon Generation Company	Supplier	Steve Kirk ( <del>tel</del> )	William Fowler	
<del>Fairchild Semiconductor Corporation</del>	<del>End User</del>			<del>Dave Cavanaugh</del>
Galt Power, Inc.	Supplier	Nancy Chafetz ( <a href="#">tel</a> )		
GDF SUEZ Energy Marketing NA, Inc.	Generation	Thomas Kaslow		
Generation Group Member	Generation	Dennis Duffy ( <a href="#">tel</a> )	Abby Krich (tel)	<a href="#">Robert Stein</a>
Georgetown Municipal Light Department	Publicly Owned		Phil Smith	
Granite Ridge Energy, LLC	Supplier		William Fowler	
Groton Electric Light Department	Publicly Owned		Gary Will	
Groveland Electric Light Department	Publicly Owned		Phil Smith	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault	Robert Stein	
Harvard Dedicated Energy Ltd	End User	<a href="#">Mary Smith</a>		<del>Roger Borghesani</del>
High Liner Foods (USA)	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Phil Smith	
Holden Municipal Light Department	Publicly Owned		Gary Will	
Holyoke Gas & Electric Department	Publicly Owned			Gary Will
Hull Municipal Lighting Plant	Publicly Owned		Gary Will	
Industrial Energy Consumer Group	End User	Donald J. Sipe		
Ipswich Municipal Light Department	Publicly Owned		Gary Will	
Jericho Power, LLC	AR		Phil Smith	
Littleton (MA) Electric Light and Water Dept.	Publicly Owned		Phil Smith	

MEMBERS AND ALTERNATES PARTICIPATING IN  
JUNE 5, 2015 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kienny	
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		
<a href="#">Maine Office of the Public Advocate</a>	<a href="#">End User</a>			<a href="#">Paul Peterson</a>
Maine Skiing, Inc.	End User	Donald J. Sipe		
Mansfield Municipal Electric Department	Publicly Owned		Gary Will	
Marblehead Municipal Light Department	Publicly Owned		Gary Will	
Massachusetts Attorney General's Office	End User	Fred Plett		
Massachusetts Development Finance Agency	Publicly Owned			
Mass. Municipal Wholesale Electric Company	Publicly Owned	Gary Will		
Merrimac Municipal Light Department	Publicly Owned		Phil Smith	
Middleborough Gas and Electric Department	Publicly Owned		Gary Will	
Middleton Municipal Electric Department	Publicly Owned		Phil Smith	
Millennium Power Partners	Generation		Daniel Pierpont <a href="#">(tel)</a>	
<del>MoArk, LLC</del>	<del>End User</del>			<del>Dave Cavanaugh</del>
National Grid	Transmission	Tim Brennan	Tim Martin	
New Hampshire Electric Cooperative, Inc.	Publicly Owned	<a href="#">Steve Kaminski (tel)</a>		Brian Forshaw
New Hampshire Office of Consumer Advocate	End User	<a href="#">Paul Peterson</a>	Sarah Jackson	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
Noble Americas	Supplier		Becky Merola	
NRG Power Marketing, Inc.	Generation	Dave Cavanaugh		
Pascoag Utility District	Publicly Owned		Phil Smith	
Paxton Municipal Light Department	Publicly Owned		Gary Will	
Peabody Municipal Light Plant	Publicly Owned		Gary Will	
PowerOptions, Inc.	End User			Sarah Jackson; <a href="#">Paul Peterson</a>
<del>PPL EnergyPlus, LLC</del>	<del>Supplier</del>	<del>Tom Hyzinski</del>		
Princeton Municipal Light Department	Publicly Owned		Gary Will	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Repsol Energy North America	Supplier	<del>Sam Moreton (tel)</del>	Nancy Chafetz <a href="#">(tel)</a>	
Rowley Municipal Lighting Plant	Publicly Owned		Phil Smith	
Russell Municipal Light Dept.	Publicly Owned		Gary Will	
<del>St. Anselm College</del>	<del>End User</del>			<del>Dave Cavanaugh</del>
Shrewsbury Electric & Cable Operations	Publicly Owned		Gary Will	
Small LR Group Member	AR	<del>Doug Hurley</del>		<a href="#">John Keene</a>
Small RG Group Member	AR	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned		Gary Will	
<del>Shipyard Brewing Co., LLC</del> <a href="#">South Jersey Energy Company</a>	<del>End User</del> <a href="#">Supplier</a>			<del>Dave Cavanaugh</del> <a href="#">Nancy Chafetz (tel)</a>
Sterling Municipal Electric Light Department	Publicly Owned		Gary Will	
Stowe Electric Department	Publicly Owned		Phil Smith	
SunEdison (First Wind Energy Marketing)	AR	John Keene		Robert Stein
Tangent Energy Solutions	Provisional Member	Brad Swalwell (tel)		
Taunton Municipal Lighting Plant	Publicly Owned		Phil Smith	
Templeton Municipal Lighting Plant	Publicly Owned		Gary Will	
The Energy Consortium	End User	<del>Roger Borghesani</del>	<a href="#">Mary Smith</a>	
<del>TransCanada Power Marketing Ltd.</del> <a href="#">Union of Concerned Scientists</a>	<del>Generation</del> <a href="#">End User</a>		<del>Mike Hachey (tel)</del> <a href="#">Francis Pullaro</a>	
United Illuminating Company (UI)	Transmission	Christian Bilcheck	Alan Trotta	
<a href="#">Utility Services Inc.</a>	<a href="#">End User</a>			<a href="#">Paul Peterson</a>
Vermont Electric Cooperative	Publicly Owned	Craig Kienny		
Vermont Electric Power Company, Inc.	Transmission	Frank Etori (tel)		

NEPOOL PARTICIPANTS COMMITTEE  
 AUG 7, 2015 MEETING, AGENDA ITEM #1  
 ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN  
 JUNE 5, 2015 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Vermont Energy Investment Corporation	AR		<del>Doug Hurley</del>	<a href="#">John Keene</a>
Vermont Public Power Supply Authority	Publicly Owned	David Mullett		
Vitol Inc.	Supplier	Joseph Wadsworth		
Wakefield Municipal Gas and Light Department	Publicly Owned		Gary Will	
Wallingford DPU Electric Division	Publicly Owned	Phil Smith		
Wellesley Municipal Light Plant	Publicly Owned		Phil Smith	
West Boylston Municipal Lighting Plant	Publicly Owned		Gary Will	
<del>Westerly Hospital</del>	<del>End User</del>			<del>Dave Cavanaugh</del>
Westfield Gas & Electric Department	Publicly Owned		Gary Will	
<del>Z-TECH, LLC</del>	<del>End User</del>			<del>Dave Cavanaugh</del>

## **PRELIMINARY**

The 2015 Summer Meeting of the NEPOOL Participants Committee was held at The Stoweflake Resort & Conference Center, Stowe, Vermont, on Tuesday, June 23, Wednesday, June 24, and Thursday, June 25, 2015, pursuant to notice duly given. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. All motions acted on at the meeting were voted on Thursday, June 25. Attachment 1 identifies the members, alternates and temporary alternates attending the meeting and voting that day.

Mr. Joel Gordon, Chair, presided and Mr. David Doot, Secretary, recorded for all three days.

### **JUNE 23, 2015 SESSION**

The June 23, 2015 session began at 2:00 p.m., following morning meetings among the Sectors, ISO Board and New England regulators, an opportunity which Mr. Gordon emphasized continued to be viewed by the NEPOOL members as extremely beneficial. Mr. Gordon welcomed the members, alternates and guests who were present, and extended a special welcome to the representatives of the New England State Commissions and other state officials, NECPUC and NESCOE (the States), the FERC, and members of the ISO Board.

### **OPENING AND WELCOMING REMARKS**

Mr. Gordon highlighted the valuable relationships among NEPOOL, NECPUC and NESCOE that had strengthened over the past several years. He emphasized that NEPOOL members welcomed participation by, and input and perspectives of, State representatives at the NEPOOL table. He also thanked the ISO Board members for their participation. He stated that ~~the~~[NEPOOL's](#) relationship with the ISO Board had, going back to the Board's formation, always

included some level of interaction, but he wished to specially recognize the current Board members for their enhanced level of engagement. He suggested that the level of engagement of the ISO Board members should be considered a best practice across all the organized markets. He likewise thanked the FERC representatives for their participation in so many of the Principal Committee meetings, but particularly when they attend in person and gave additional opportunities inherent in two-way communications. ~~Though unable to attend,~~ Mr. Gordon made special mention of Mr. Eric Jacobi, who [was unable to attend but](#) had [recently](#) taken a position with FERC as its representative on the ground in New England, working out of the ISO's facilities in Holyoke.

Mr. Gordon previewed the remainder of the business agenda and meeting schedule, and thanked the NEPOOL team from Day Pitney for their efforts planning and facilitating the Summer Meeting.

Mr. Gordon then invited [Commissioner Paul Roberti of the](#) Rhode Island Public Utilities Commission (RI PUC) ~~Commissioner Paul Roberti~~ to provide opening remarks on behalf of NECPUC. Commissioner Roberti began by relaying NECPUC President Meg Curran's regrets for being unable to participate in the Summer Meeting. He then proceeded to read the comments that Chairperson Curran had prepared for the meeting, which provided her insights and appreciation gleaned over the past few months for the NEPOOL process, collaboration, and relationship building.

Commissioner Christopher Recchia, Vermont Public Service Department, on behalf of the State of Vermont, officially welcomed NEPOOL to the Green Mountain State. He thanked the members and ISO Board members for the opportunity to attend the meeting and meet with them. He described his experiences with NEPOOL, highlighting the level of cooperation among

the Participants. He found the Sector meetings useful, and noted his perception of a level of commonality that would provide an opportunity for the region to collaborate successfully on energy security, energy stability, and economic competitiveness with the rest of the nation.

## **FERC REGIONAL UPDATE**

Mr. Gordon introduced Ms. Jignasa Gadani, the Deputy Office Director of the Office of Energy Policy and Innovation (OEPI) at the FERC. Ms. Gadani reminded the Committee that, at the 2014 Participants Committee Summer Meeting, she had reported on plans to establish a New England regional office under the auspices of the Office of Energy Market Regulation (OEMR). She reported that the office had been established and that Mr. Jacobi would be the Energy Industry Analyst focusing on New England activities for that office. She thanked NEPOOL for its support for that initiative.

Ms. Gadani then noted that she had taken her new position with OEPI six months before, and provided an overview of OEPI. She explained that OEPI provided leadership in the development and formation of policies and regulations to address emerging issues affecting wholesale energy markets. Ms. Gadani then identified and provided a brief overview of the following four key policy issues of focus for OEPI: (1) gas-electric coordination; (2) price formation; (3) fuel assurance; and (4) Order 1000 implementation.

In response to a question on how best to provide information and input to her and OEPI, both at the Summer Meeting and going forward, Ms. Gadani suggested that Participants could meet with either her or her colleague from OEMR, Mr. Kristopher FitzPatrick, who was also in attendance, through the end of the meeting, or reach them by phone, e-mail, or in-person ~~visit~~ at the FERC. She explained OEPI worked closely with the FERC's Office of General Counsel and OEMR on emerging issues/trends, ~~as well as with the General Counsel's Office if there were~~

**legal issues.** She encouraged outreach to any of those officers, specifically noting that Ms. Jamie Simler [and Mr. Kurt Longo](#) of OEMR could also direct Market Participants to the appropriate staff person depending on the issue.

Ms. Gadani summarized in response to [a](#) question the procedural status of Order 809 (Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities) and the FERC's proceeding to evaluate price formation issues in RTO/ISO energy and ancillary services markets. She indicated that RTO/ISO responses to Order 809 were due shortly and FERC Staff was still reviewing the comments submitted in the price formation proceeding. Given the status of the proceedings, she was not able to provide a specific timeline for FERC action on either proceeding.

## **EXTERNAL MARKET MONITOR (EMM) REPORT**

Dr. David Patton, Ph.D, President, Potomac Economics, the ISO's EMM, presented highlights from the EMM's 2014 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. He explained that the purpose of the Report was to reflect Potomac Economics' assessment of the efficiency and competitiveness of New England's wholesale power markets in 2014, to identify and recommend necessary changes to existing and proposed Market Rules, Tariff provisions, and market design elements, and to evaluate the quality and appropriateness of mitigation by the ISO's Internal Market Monitor (IMM). He reported, based on the EMM's evaluation of the markets, that New England's energy and ancillary services markets performed competitively in 2014. He had recommended improvements to increase the competitiveness of New England's Forward Capacity Market (FCM) that would be reviewed in his presentation.

Dr. Patton reviewed the short- and long-term benefits of New England's Markets. In the short-term, he noted that the Markets facilitate the efficient daily commitment of New England's resources and the efficient dispatch and management of congestion. He stated that the price formation issues being addressed by the FERC provide important incentives for suppliers to be flexible and to respond well to dispatch signals, which in turn provides enhanced reliability through improved system coordination. Over the long-term, market signals should facilitate efficient investment and retirement decisions by Participants.

Dr. Patton then turned to a series of graphs illustrating a comparison of energy and natural gas prices in 2013 and 2014. He explained that 2014 was characterized by extremely cold weather and tight natural gas market conditions in the first quarter, followed by very mild weather and historically low natural gas prices through the rest of the year. Natural gas prices increased 73% in the first quarter from 2013 prices and then decreased 26% through the rest of the 2014, resulting in a net price increase of 16% in 2014 [over 2013](#). He reported that energy prices rose 77% in the first quarter from 2013 prices and decreased 23% through the rest of 2014, resulting in a net price increase of 14% [in 2014 over 2013](#). He concluded that the strong relationship between energy and natural gas prices indicated a well-functioning, competitive market.

Turning to a comparison of 2013 and 2014 Day-Ahead and Real-Time prices, Dr. Patton stated that 2014 implied heat rates were slightly higher than the 2013 rates, indicating there were some tight conditions that contributed to higher energy prices that exceeded the increase generated by natural gas prices. One Market Participant commented that the annual average implied heat rate in 2014 was 8.5 MMbtu/MWh, up slightly from 2013, but down slightly from 2012, and asked whether more analysis of long-term trends was needed. Dr. Patton explained

that one factor causing the implied heat rate to be higher in some years was comparatively higher energy prices during July and August because of periods of tightness. Because winter 2013/14 was so mild that phenomenon did not occur; explaining why implied heat rates were lower than in 2012. Commenting on the chart reflecting the implied heat rates, a member questioned why some average heat rates broken down by month were below the most inefficient heat rate on the system. Dr. Patton responded that a drawback of the implied heat rate was the assumption that gas was always setting the price, because in any period when Participants switch away from gas ~~to~~ non-gas units on the margin, the result can be deceptively low implied heat rates. He stated that it was important to recognize that implied heat rates also could be materially impacted by significant spreads among the region's natural gas pipeline fuel prices. To address that concern, a member requested that Dr. Patton create a chart reflecting the average ~~of~~prices among the three natural gas pipelines in New England and the higher oil prices in order to get a smoother curve on the heat rate to better measure fluctuations throughout the year.

Dr. Patton then reviewed a comparison of Real-Time price volatility in 2013-2014 between the New England Markets and some of the other RTOs in the Eastern Interconnection. He referred to a chart reflecting the average change from one 15-minute period to the next, with New England experiencing significantly lower volatility than any of the other RTOs. He attributed New England's lower volatility to a number of factors including: (i) longer dispatch periods in MISO and PJM than in NYISO and New England, who each dispatch on a five-minute basis, creating significantly less flexibility and more frequent ramp constraints than New England and New York; (ii) fewer large schedule changes for imports and exports; and (iii) higher shortage pricing in the other RTOs. However, he added that New England price volatility would increase, and become more comparable to the other RTOs, with the recent changes to the

Reserve Constraint Penalty Factor (RCPF) and the addition of the Supplemental Reserve Category.

In response to a member's question, Dr. Patton statedd that implementation of Inter-Regional Interchange Scheduling (IRIS) and coordinated transaction scheduling (CTS) between New York and New England would change price volatility. He stated CTS would allow operators to improve assumptions and reliance on Real-Time interface response, reducing reliability commitments, and lowering NCPC, but increasing volatility. There would also be periods where shortages would be avoided due to more efficient interface scheduling, reducing volatility.

Dr. Patton then reviewed a chart reflecting average and peak load during 2012-2014, noting two periods in 2014 that were distinctly different: (i) the very high loads in the 1st quarter and (ii) the very mild loads during the 2nd through 4th quarters. He concluded that these load conditions impactedd the frequency of shortages experienced through the year and helped explain some of the pricing patterns.

Dr. Patton reported that Operating Reserve prices were slightly lower in 2014 than 2013, but were roughly consistent with the kind of prices seen in other markets for similar products. He noted that New England was one of the only RTOs that did not have day-ahead reserve markets. The EMM viewed this as a shortcoming and had been recommending and continued to recommend atthat New England implement a day-ahead reserve market ~~be implemented~~. He explained that day-ahead reserve markets are valuable because they provide commitments to suppliers who can procure fuel day-ahead for the next day. Because of these earlier commitments, the RTOs can effectively jointly optimize the procurement of reserves and energy in the day-ahead timeframe when commitment instructions are established, which should

produce a more efficient commitment of resources. Dr. Patton pointed out that New England Forward Reserve Market (FRM) prices did not resemble Real-Time 30-Minute or 10-Minute Operating Reserve prices.

In response to comments and clarifying questions, Dr. Patton acknowledged that differences in reserve pricing from market to market were influenced by requirements and types of resources, noting that New England had a fair number of combined cycle units, which were really good providers of reserves, particularly spinning reserves. He explained that fast-start resources were fully priced in New England's Reserve and Energy Markets, and units were providing the System with two benefits in particular: (1) assistance satisfying resource adequacy planning requirements; and (2) the ability to satisfy reserve requirements and meet energy demands during a contingency or period of higher than expected load. The FRM, he explained, was essentially a specialized capacity market, rather than an actual reserve product market. The FRM did not correspond to reliability requirements from an operating standpoint, did not result in reserves in Real-Time, and had very little impact on Real-Time prices. He explained that a day-ahead reserve market would produce somewhat higher day-ahead reserve prices than Real-Time prices (except during shortages when prices tended to equalize).

Comparing uplift costs during 2013 and 2014 among New England, NYISO and MISO, Dr. Patton indicated that New England used to have among the largest uplift, primarily due to second contingency protection costs incurred in Boston and Connecticut. After transmission upgrades were put in place, NCPC decreased significantly. Although NCPC was lower than prior years on a per MWh load basis, NCPC was much higher in comparison to MISO and significantly higher than in NYISO. The uplift related to local reliability issues were down significantly in 2014 from 2013. He stated one of the EMM recommendations addressed Real-

Time uplift, both local reliability and system-wide, which was anticipated to be much higher in 2015 than in 2014 due to Energy Market Offer Flexibility (EMOF) changes implemented in December 2014. He concluded that uplift in New England was higher even before the EMOF changes, suggesting room for significant improvement. Dr. Patton was pleased that the FERC shared his focus on improving price formation so LMPs better reflect the full cost, thereby reducing uplift.

Dr. Patton reported that gas price volatility and certain peaking conditions had materially impacted uplift, with 45% of NCPC accrued in January. In 2015, the relatively significant NCPC levels continued. He expressed concern with the \$60 million in new NCPC associated with the EMOF changes, which he concluded was the sole reason why NCPC levels in 2015 had not dropped nearly as much as expected in comparison to the Polar Vortex period. Both the EMM and the ISO were studying this development.

Turning to FCM and comparing results from FCA8 and FCA9, Dr. Patton highlighted that there were administrative pricing rules triggered in both FCAs, with the Insufficient Competition Rule triggered in FCA8, which resulted in the bifurcated pricing that paid new resources \$15/kW-mo. and existing resources \$7/kW-mo. Dr. Patton found that result particularly disturbing because almost the entire theory and benefit of FCM hinges on robust competition from new capacity. As a result, a number of the EMM recommendations focused on facilitating participation by new resources and improving the competitiveness of participation by those resources. In FCA9, he reported the Inadequate Supply administrative pricing rule was triggered, resulting in local prices in the SEMA zone of \$17.73/kW-mo. for new resources and \$11 /kW-mo. for existing resources.

Dr. Patton highlighted another recommendation to develop local demand curves based on observations of local demand curves that had been implemented by other RTOs. He stated that implementation of local demand curves would provide the mechanism to price Inadequate Supply. He identified concerns with the form of zonal curve solution that the region had considered which treats subareas of the System independently and recommended that any zonal curve solution recognize the interdependence of subareas. He stressed the importance of ~~that initiative and~~ sloped demand curves in local zones and the transition away from the Inadequate Competition/ Inadequate Supply administrative pricing rules.

Following a brief review and discussion of charts reflecting long-term price signals and net revenue for 2014, potential physical and economic withholding, and Real-Time automated market power mitigation in 2014, Dr. Patton concluded his presentation by reviewing the following recommendations with respect to the Energy, Reserve and Capacity Markets, and addressing numerous follow-up questions:

- Allow the costs of fast-start resources, operator actions, and demand response deployments to be reflected in Real-Time prices;
- Implement provisions to coordinate the physical interchange between New York and New England in Real-Time;
- Modify allocation of “Economic” NCPC charges to make it more consistent with “cost causation” principles;
- Eliminate Real-Time NCPC payments intended to recover commitment costs for non-fast-start resources scheduled in the Day-Ahead Energy Market;
- Utilize the lowest cost configuration for multi-unit generators when committing resources for local reliability;
- Consider introducing Day-Ahead Operating Reserve markets that are co-optimized with the Day-Ahead Energy Market;
- Consider eliminating the Forward Reserve Market;
- Introduce eligibility requirements governing the use of Non-Price Retirement De-List Bids;

- Determine sloped demand curves for FCA11 that recognize the interdependence of the demand for capacity in different zones and system-wide; and
- Modify interconnection and FCM rules to foster robust competition from new resources and imports in the FCA.

The June 23 session then adjourned at 4:55 p.m., with the meeting to be reconvened promptly at 8:30 a.m. on June 24.

## **JUNE 24, 2015 SESSION**

The Summer Meeting reconvened at 8:30 a.m. on June 24, 2015. Opening the session, Mr. Gordon introduced Commissioner Recchia, who offered brief remarks then introduced the Honorable Peter Shumlin, Governor of Vermont.

### **REMARKS BY VERMONT GOVERNOR PETER SHUMLIN**

Governor Shumlin welcomed everyone to Vermont. Governor Shumlin offered his thoughts and observations on the challenges facing Vermonters, the New England region, and the electric industry and its professionals. He described efforts underway in Vermont to increase innovation, create jobs, save Vermonters money, and continue progress combating climate change. He discussed issues associated with the build-out of generation resources, transmission bringing shale gas, hydropower and other renewable resources into the region, and Vermont's participation in those efforts. He expressed his hope that, together, the region could achieve more predictable, lower cost, cleaner and greener energy. Governor Shumlin concluded his remarks by encouraging members to enjoy and to make the most of their time in Vermont.

### **REMARKS BY FERC COMMISSIONER COLETTE HONORABLE**

Mr. Gordon welcomed and introduced the Honorable Colette Honorable, the most recently appointed FERC Commissioner. Commissioner Honorable thanked the Committee for welcoming her. She stated that it had been a pleasure to meet with NEPOOL members and representatives and hear more about the region's history, processes and current efforts. She recognized numerous regulators with whom she had worked previously in her leadership role in

the National Association of Regulatory Utility Commissioners (NARUC), and Participants with whom she had met prior to the Summer Meeting.

Referring to the 2014 NEPOOL Annual Report, Commissioner Honorable highlighted the Report's emphasis on collaboration and consensus. That emphasis was particularly poignant to her. She explained that collaboration and consensus formed the foundation for the work that had to take place, as the region and industry faced emerging, fast-paced, and dynamic challenges. She stated that the ability to address the major issues, like transmission planning, cost allocation, system constraints and capacity issues, all turned on trust, and a belief that colleagues would help carry the weight. She encouraged Participants to share with her and her staff the region's concerns, priorities, processes, and impacts of FERC orders, rulemakings, and policy statements, particularly from an "on the ground perspective."

Commissioner Honorable then proceeded to explain three key areas of current focus in her role as a FERC Commissioner: reliability, infrastructure and fuel diversity, and markets. With respect to reliability, Commissioner Honorable addressed the work being undertaken in response to the U.S. Environmental Protection Agency's (EPA's) proposed Clean Power Plan (EPA Clean Power Plan), then the predominant issue at the FERC. She suggested that the work was indicative of new challenges facing the industry and how the FERC was responding to the need for a cleaner, more sustainable and affordable energy future. She commended the Northeast for its efforts and leadership, noting the abundant clean resources available to the region. Commissioner Honorable observed that not all regions were equally blessed with sources of renewable power, and stated that she respected regions' needs to use the resources available to [itthem](#), which in turn supported the need for regional diversity. Above all, however,

she stated that the FERC needed to be vigilant with respect to, and improve upon, what she characterized as the most reliable system in the world.

To that end, she indicated that the FERC had provided feedback to EPA, signed by all five Commissioners, urging the EPA to provide resources with a “reliability safety valve” (allowing for some advance notice of a need ~~of~~[for](#) a generation resource to run in emergent or unexpected events, but with an opportunity to make up for additional emissions after the fact), and to solicit and coalesce in a broader process the perspectives of all those who regulate or participate in the industry. That feedback reflected, in turn, the comments submitted to the FERC at the regional technical conferences. She thanked all who participated in those conferences.

Commissioner Honorable commended the New England region for its work on transmission issues, which she viewed as a model for the rest of the country. She also highlighted the Regional Greenhouse Gas Initiative (RGGI) as a leading model on how to address carbon issues going forward.

Addressing infrastructure and fuel diversity, Commissioner Honorable stressed the need for sufficient infrastructure to enable a cleaner, more sustainable energy future. She suggested the need, nationally, for additional and better transmission and pipelines. She stated that she supported an “all of the above” approach, which avoided the need to pick winners and losers, and would ensure that all fuels could be competitive. She was confident that, with commitment and a strong collaborative foundation, the industry could achieve consensus and collectively move towards a cleaner energy future that serves the ultimate consumer. Examples of such efforts included the work on Order 1000 on the electric side (with work on the first cycle of regional and interregional filings just completed), the FERC’s policy statement on cost treatment of

modernization of natural gas infrastructure (of particular importance to New England during the peak winter months), and swifter compensation for infrastructure modifications enhancing resiliency, reliability, safety, or environmental purposes. She added that each of these also illustrated the FERC's openness to new ideas and new ways of doing things in order to move towards a cleaner and more sustainable energy future.

Turning to markets and price formation issues, Commissioner Honorable stressed that making markets work was imperative. Referring to information and understandings converged in the price formation ~~rule-making~~[rule-making](#) docket (AD14-14), she acknowledged the industry's need for certainty in the markets, comprehensive, consistent treatment of market issues, and transparency and openness to build confidence and participation in the wholesale markets. She referenced the FERC's efforts in the gas-electric interdependency proceeding, explaining the FERC's efforts to balance the diverse needs of both the gas and electric markets by requiring additional intra-day nomination cycles to allow for more market flexibility. She cautioned that the work on these issues was on-going. She encouraged stakeholders to continue sharing their thoughts on improvements.

In response to questions, Commissioner Honorable, referring to her experience as a stakeholder in the Southwest Power Pool, confirmed that the FERC recognized and respected the challenges in achieving consensus. She opined that the FERC should be disciplined about jumping into regional issues, though not hesitant to show leadership, if and to the extent necessary, and make a call where consensus was not attainable or a just and reasonable outcome must be ensured. She stressed that the FERC must demonstrate and support confidence in the stakeholder process and certainty and comfort that the process be given a chance to work in the first instance. She acknowledged the challenges that philosophy presented, but encouraged

stakeholder persistence and hard work nonetheless. She also suggested that the FERC could help guide regions by (1) encouraging robust stakeholder processes (reviewing, where and as necessary, state transmission plans); (2) employing administrative tools, like technical conferences, to encourage dialogue and support the challenging balancing act that RTO/ISOs were asked to perform; and (3) staying involved in and staying committed to improving stakeholder processes.

Commissioner Honorable reiterated her observation that the NEPOOL stakeholder process appeared~~s~~s to be robust and to work effectively. She urged Participants to reflect on the region's accomplishments, which she believed were the fruit of a significant investment of time, talent and resources. She cautioned that the region was still facing a number of challenges, particularly related to reliability in the winter months, and with respect to capacity issues, challenges that she was confident could be worked through and addressed.

#### **PANEL DISCUSSION: "2015 STATE LEGISLATIVE ENERGY DEVELOPMENTS"**

Mr. Gordon introduced the following panelists: Ms. Sandi Hennequin, Vice President, U.S. Public Affairs, Emera Energy, Mr. Daniel Allegretti, Vice President, Energy Policy, Exelon Corporation, and Mr. Joseph Dalton, Director, Government & Regulatory Affairs, GDF Suez Energy North America. Mr. Dalton, after singing a few lines from the classic Saturday morning cartoon "I'm Just a Bill", moderated an update and discussion of energy legislative developments in, and across, the New England States, with Ms. Hennequin and Mr. Allegretti summarizing developments in each of the New England states~~houses~~houses. As a complement to the discussion, a printed copy of the 2015 legislative summary capturing those developments (Summary) was distributed. Mr. Dalton thanked Ms. Jennifer Galiette and Mr. Harold Blinderman ([NEPOOL Counsel](#)) for their efforts preparing the Summary, and Ms. Heather Hunt ([NESCOE](#)) and Ms.

Rachel Goldwasser ([NECPUC](#)) for their efforts in finalizing the state representatives' contributions.

Mr. Dalton described through examples a recent evolution from individual state efforts to coordinated and cooperative multi-state efforts. He identified efforts in the most recent legislative sessions [across New England](#) to introduce and enact legislation to support and advance those cooperative efforts. He also noted, on the [f](#)ederal side, the substantial level of [f](#)ederal activity and interest, citing energy-related bills offered and sponsored by members of New England's delegation. Energy legislation, he summarized, had moved to front and center from both a [s](#)State and [f](#)ederal perspective.

### *Connecticut*

Mr. Allegretti began by noting that, while a host of bills are introduced every year in each of the New England states, Connecticut is the one state where each year there is active energy legislation and some new energy law enacted. He highlighted two major pieces of Connecticut legislation -- Public Act Nos. 15-107 (An Act Concerning Affordable and Reliable Energy) (Competitive RFPs Act) and 15-90 (An Act Concerning Variable Electric Rates) (Variable Rates Act). He summarized the competitive RFPs Act, which authorized Connecticut regulators to direct long-term contracting for renewables, for the support of natural gas pipeline infrastructure, and for the transmission and supply of hydro power from Canada, and allows electric distribution companies to seek cost recovery for the costs of entering into any long-term agreement selected by the regulators through the RFP process.

Mr. Allegretti explained that the other major piece of legislation, the Variable Rates Act, focused on the retail market. Picking up where Public Act 14-75 (which provided for a more comprehensive set of consumer protections and industry obligations to retail customers in part in

response to price volatility issues experienced by customers under pass through rates during the Polar Vortex) left off, some [advocates](#), including AARP, tried to ban ~~pass-through~~[pass-through](#) (or month-to-month) rates altogether. He reported that, rather than an outright ban, a compromise had been achieved that directed the Public Utilities Regulatory Authority to develop and report back to the legislature on recommendations regarding rate structures for residential customers switching to variable rate contracts and what increases might be just and reasonable when a customer transitions from a fixed rate contract to month-to-month rates. He provided additional insight into 11th hour efforts, ultimately unsuccessful, to clarify language in the Variable Rates Act through an subsequent, omnibus energy bill.

### *New Hampshire*

Moving north, Ms. Hennequin provided background and context with respect to legislation necessary to support a settlement agreement reached between Eversource (formerly Public Service Company of New Hampshire) and New Hampshire state officials addressing cost recovery for certain installed environmental controls at Eversource's Merrimack Station, divestiture of Eversource's entire rate-based generation portfolio, and securitization of the related stranded costs (SB221 – An Act Relative to Electric Rate Reduction Financing). She reported that the bill, supported by both chambers, and which would be effective upon passage, had been submitted to the [New Hampshire](#) [g](#)Governor for signature.

Ms. Hennequin turned to HB572 (An Act Relative to Taking Land by Eminent Domain for High Pressure Gas Pipelines and Relative to the Siting of High Pressure Gas Pipelines), which she explained was, in part, a response to local opposition to Kinder Morgan's Northeast Energy Direct (~~NED~~) Project. She stated that the Act required the New Hampshire Site Evaluation Committee to adopt rules on and provide guidelines for gas siting within 12 months.

The Act also required the Site Evaluation Committee to consider interventions in FERC proceedings involving siting of high pressure gas pipelines. She predicted that Act was likely to move forward and become law. She highlighted other energy bills that were retained in committee and would be taken up at the beginning of the next session.

~~As in Connecticut,~~ Ms. Hennequin reported that, [as in Connecticut](#), there had been a number of bills focused on cost and consumer protections, particularly given large increases in the state's utilities' winter default rates. Of those, SB 170 (An Act Requiring the Public Utilities Commission to Ensure Ratepayer Protections with Electric Power Suppliers and Extending the Time for the Site Evaluation Committee to Adopt Certain Rules) was the most likely to become law. She summarized other bills introduced, but which were tabled or died, to change how RGGI auction proceeds are rebated or invested in energy efficiency programs, to change renewable portfolio standards, and recurring bills in response to opposition to Northern Pass.

### *Massachusetts*

Mr. Allegretti began by distinguishing the Massachusetts legislative process from others in New England, including its year-round legislative sessions and committee structures. He reported that several energy bills covering a broad spectrum of topics had been considered, including legislation addressing regional infrastructure (natural gas pipeline expansion, Canadian hydropower-related transmission, off-shore wind) and more local energy issues (microgrids, increasing solar energy sales, adjusting net metering caps).

He went on to explain, however, how a broader disagreement among legislators regarding Massachusetts' tradition of having a mix of joint- and single-chamber committees had effectively created "cameral grid lock". Notwithstanding the Joint Committee on Telecommunications, Utilities and Energy's history of productive and successful collaboration, broader concerns with

and disagreements regarding the joint committee structure were effectively preventing any energy legislation from getting through the full chambers. Mr. Allegretti stated that it was not likely that any major energy legislation would be passed until sometime in 2016. Such legislation was likely to include many of the issues identified he identified earlier and package them in an omnibus fashion.

### *Maine*

Ms. Hennequin explained that, like Massachusetts, Maine also has a Joint Committee on Energy, Utilities and Technology, which experienced significant political change as it entered the 2015 portion of Maine's two-year legislative session, with two-thirds of the committee being new members, including both chairs. In addition, the Joint Committee was tasked with nomination hearings for, and making recommendations to, the senate on two new Maine Public Utilities Commission (MPUC) Commissioner appointees.

Ms. Hennequin reported that there were more than 30 energy bills introduced during the session, including two meant to address the unintentional omission of the word "and" from prior legislation. She explained that the omission had the potential to cost the state efficiency program (Efficiency Maine Trust) more than \$38 million annually. The first bill, which proposed to just correct for the omission, had passed, but had been vetoed by the Governor. The Governor preferred a second bill, which he had introduced, that corrected the omission, but also would make the director of the Efficiency Maine Trust a cabinet level position, and empower the governor to name Efficiency Maine Trust Director. The governor's bill was proceeding through the process.

Ms. Hennequin next described a bill, that passed and had been signed into law, that created a threshold capacity of 500 MW for a nuclear power plant for which a referendum

approving construction is required as part of Maine's siting process. She also briefly summarized a number of other bills that had been considered and either rejected or carried over to the second portion of Maine's legislative session. Bills carried over would have allowed the MPUC to contract for the storage and distribution of liquefied natural gas (LNG) during peak winter months, would have created the necessary framework for governmental entities to enter into contracts with private entities to develop or operate infrastructure projects, including power generation or fuel supply facilities, and oil or gas pipelines, and would have allowed investor-owned transmission and distribution utilities to own generation assets if the MPUC determines that ownership is beneficial to the utility's ratepayers. She explained that carried over bills would have to be acted on in early 2016. She expected there to be fewer energy bills in the 2016 portion of the legislative session.

### *Vermont*

Mr. Allegretti described the background behind Vermont legislation creating a renewable energy standard for the [s](#)State's retail electricity providers (An Act Relating to Establishing a Renewable Energy Standard (H. 40)). H. 40, which addresses concerns with the counting of renewable energy credits (REC) and consistency with underlying public policy goals, allows Vermont's providers to participate in New England's REC marketplace on the same terms as those in other New England states. He reported that H. 40 was signed into law by Governor Shumlin on June 12 and would take effect on January 1, 2017.

### *Rhode Island*

Ms. Hennequin explained that Rhode Island did not have a legislative committee dedicated to energy, meaning energy bills typically make their way through the Environmental,

Commerce, or Finance Committees. She stated that the big issue in the 2015 legislative session, similar to other New England ~~s~~States, was concern over high electric rates. With National Grid having announced a significant rate increase for their default customers during the winter period ahead of the session, much of the energy legislation introduced was driven by rate concerns, as demonstrated by the fact that more than one-half of the 13 energy-related bills addressed the rate increase issue.

Two other bills of interest that had passed the House during the 2015 session included one which revised the definition of “Renewable Net Metering Credit” and increased the maximum allowable capacity for eligible net-metering systems from 5 MW to 10 MW. The second would direct the RI PUC to establish a bill of rights for retail consumers. Both had been scheduled for Senate Commerce Committee consideration that week (and prior to the end of the session), which kept the possibility alive that the bills could, rather than die, move forward into the next session.

Mr. Dalton noted that the Legislative Summary, while current as of the date of printing, was still under development. Mr. Blinderman stated that the Report in its current version would be posted in the NEPOOL eLibrary and would then be updated to capture any remaining developments from the closing days of the States’ sessions and re-posted in the NEPOOL eLibrary.

## **INTER-REGIONAL ISSUES DISCUSSION WITH NYISO PRESIDENT & CEO**

Mr. Gordon introduced and welcomed Mr. Stephen Whitley, President and CEO of the New York ISO (NYISO) to discuss interregional issues affecting New York and New England.

Mr. Whitley began his discussion by providing an overview of the recently completed NYISO 15-Year Review of the markets. The Review described the benefits achieved over the

past 15 years from New York's wholesale markets, which included: \$6.4 billion in reduced fuel costs due to system efficiency improvements that exceeded national efficiency gains by 300%; \$540 million in cost savings from reduced reserve requirements; 25 million tons of carbon emissions avoided in 2013 versus 1999; and integration of enough wind generation to provide power to almost 500,000 homes per year in New York (with another 3,000 MW of wind in the queue).

Mr. Whitley then highlighted the evolving interregional challenges and opportunities facing New York (and as well other regions). First, he noted that energy demand in New York was not growing and, with increased energy efficiency and distributed resource impacts, demand was projected to be flat over the next decade. He explained that the #1 challenge for both New York and New England was the growing dependence on natural gas. While New York was fortunate to have a lot of non-gas resources in the north with hydro, wind and nuclear, generation in southern New York was almost exclusively fueled by gas or oil. Given this reality Mr. Whitley opined that getting more natural gas pipeline infrastructure built in New York and having dual-fuel capability were imperatives.

Given the importance of having the flexibility to switch to oil when needed, he noted one of his concerns with the EPA's Clean Power Plan, which would put restrictions on oil use even for the few hours that such fuel would be needed during times of system stress. Speaking further on the proposed eClean pPower pPlan, Mr. Whitley also expressed concerns that the pPlan would affect over 80% of the total capacity in New York and that the pPlan would not recognize the progress that New York had already made in reducing carbon emissions because, as proposed, the EPA would not count existing renewable generation for compliance purposes. He highlighted an overarching concern that the eClean pPower pPlan would be disruptive to the

markets and explained that his goal for the industry to work together with the EPA, the New York Department of Public Service and other ~~s~~States to come up with a regional solution to these issues.

Mr. Whitley then described a third challenge facing New York and other regions from the increased growth of distributed energy resources (DG) and highlighted the need to develop a balanced plan to ensure reliability of the centralized grid and integrity of the wholesale markets. With respect to this issue, he also provided the Committee with an overview of New York's Reforming the Energy Vision (REV), which is a plan to create a marketplace at the distribution level and integrate that market into the wholesale level to bring value to consumers.

Mr. Whitley concluded his remarks by identifying areas of interregional collaboration where success had been and continued to be achieved, including RGGI, [the Broader Regional Markets initiative](#), market solutions to improve the efficiency of electricity trades between regional markets (e.g., the Coordinated Transaction Scheduling (or CTS) project), interregional planning efforts through the Eastern Interconnection Planning Collaborative (EIPC), and interregional data sharing efforts through the Eastern Interconnection Data Sharing Network (EIDSN). He ended by stating his belief that the regions worked well together, that the markets had worked well<sub>s</sub> and that he looked forward to continued interregional efforts to help address the major challenges facing the regions.

In response to questions, Mr. Whitley commented that, with respect to New York's transmission infrastructure needs, a transmission build-out would be required as more renewables ~~, being built~~power in northern New York~~, would~~ need<sub>s</sub> to get ~~that power~~ to load centers ~~down state~~in Downstate New York. Mr. Whitley contrasted his experiences working for an RTO in a single-state region (like New York) versus an RTO spanning multiple states (like

New England). He explained that pressure exerted in a single-state region concerning short-term cost impacts of the wholesale markets was more challenging, but that reliability issues were sometimes easier to address.

On behalf of NEPOOL, Mr. Gordon thanked Mr. Whitley for his remarks and the June 24 session then adjourned at 11:45 a.m., with the meeting to be reconvened at 9:30 a.m. on June 25.

## **JUNE 25, 2015 SESSION**

The Summer Meeting reconvened at 9:30 a.m. on June 25, 2015, with reports on the organized networking events held the prior afternoon. Mr. Gordon then shared comments he had presented as Participants Committee Chairman at the recent NECPUC [sSymposium](#), synthesizing NEPOOL's history, the make-up of its members, NEPOOL's roles and objectives, and the NEPOOL processes that help navigate and bring about the ongoing evolution of the wholesale electric power industry. He thanked the members for their unique perspectives, [their](#) participation and engagement in the stakeholder process, and [their](#) support during his term as Chairman.

## **REPORT OF THE ISO CHIEF EXECUTIVE OFFICER**

Mr. Gordon van Welie thanked the Sectors for their engagement in the Sector/ISO Board meetings that had been held prior to the meeting's first session and for the conversations during the various meeting activities. He reported positive feedback from Board members and Participants alike, indicated that the structure of the meetings appeared to be working, and encouraged anyone with thoughts on refinements to that structure to let him or Mr. Gordon know.

Mr. van Welie then previewed a preliminary 2016/17 budget presentation to be presented by Mr. Robert Ludlow, ISO Vice President, Chief Financial & Compliance Officer, and proceeded to describe a proposed process to accelerate the discussion of business priorities during the work plan/budget cycle. Mr. Gordon added that, based on Participant feedback, the process was intended to permit NEPOOL to provide more proactive feedback on priorities to be

undertaken during the following fiscal year. He reviewed the preliminary timeline for accomplishing that task.

## **REPORT OF THE ISO CHIEF FINANCIAL OFFICER**

Mr. Ludlow then referred the Committee to the ISO 2016/17 Preliminary Operating and Capital Budget presentation included with the materials posted in advance of the meeting, which he indicated had also been shared and discussed with state representatives at the NECPUC Symposium the week before. He described key differences from the 2015 operating budget, which included increases related to cyber security investments (including a 24 x 7 cyber security control center), market monitoring activities (to support FCM-related efforts), and administrative expenses (compensation and employee benefits). He stated that the 2016 and 2017 operating budgets were projected to each increase by 4%, while the 2016 capital budget was projected to decrease by \$1 million from the 2015 budget. Mr. Ludlow identified key items that could require additional resources and funding, including cyber security initiatives, legal and material litigation costs, and new federal and state policies. He noted and explained why the costs of Order 1000 implementation and Price Responsive Demand (PRD) integration had been deferred and not included in the operating budget.

Mr. Ludlow and Mr. Ken Dell Orto, Budget & Finance Subcommittee Chairman, identified the schedule for the remaining processes for budget review and votes by the Participants Committee. The proposed budgets were scheduled for review with the Budget & Finance Subcommittee and State representatives in late August and with the Participants Committee in September. In early October, the Participants Committee would be asked to vote on ~~support~~ the budgets, and then they would be submitted to the ISO Board to approve. The

2016 Budgets would then be filed with the FERC in mid-October with a requested January 1, 2016 effective date.

In response to questions regarding the preliminary 2016 \$/KWh rate, Mr. Ludlow explained that roughly 60% of the percentage increase from the 2015 rate was attributable to the difference between the \$9.8 million true-up (from prior years' over-collections) reflected in the 2015 rate and the much smaller \$0.6 million true-up reflected in the 2016 rate. He also confirmed that estimated staffing levels did not yet account for additional efforts, yet to be defined, associated with Order 1000 implementation. He explained expectations that existing resources could be used to cover such activities when they are defined, backstopped as necessary by contingency funds built into the budgets.

## **CONSENT AGENDA**

Mr. Gordon referred the Committee to the Consent Agenda that was circulated in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved, with abstentions noted by Eversource, Littleton (NH), UI, VEC, and VPPSA.

## **ORDER 1000 INTERREGIONAL COMPLIANCE CHANGES**

Mr. Donald Gates, ~~as Chair and on behalf of the~~ Transmission Committee [Chair](#), referred the Committee to and summarized the materials circulated and posted in advance of the meeting related to revisions to the ISO Tariff and to the Amended and Restated Northeastern Planning Coordination Protocol (the Protocol) proposed in response to the FERC's May 14, 2015 order on interregional compliance with Order 1000. He reported that the Transmission Committee had recommended unanimously Participants Committee support for both sets of changes at its June 18 meeting. He also reported that, since that meeting, further revisions to the Protocol had been

made following review by PJM, which had not completed its review before the Transmission Committee's consideration. He said those further revisions were circulated and posted with the additional materials for the Participants Committee meeting, and that he, and Mr. Jose Rotger, Transmission Committee Vice-Chair, agreed that the revisions were non-substantive. Mr. Gates indicated that the motions to support the Tariff and Protocol changes would have been on the Consent Agenda but for the timing of the Transmission Committee action.

The following two motions were then duly made, seconded, and together were unanimously approved:

RESOLVED, that the Participants Committee supports the revisions to Sections I and II of the ISO-NE Tariff proposed in response to the FERC's May 14 Interregional Compliance Order, as reflected in the materials distributed to the Participants Committee for its June 25, 2015 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

and

RESOLVED, that the Participants Committee supports the revisions to the Protocol in response to the FERC's May 14 Interregional Compliance Order, as reflected in the revised materials distributed to the Participants Committee for its June 25, 2015 meeting, together with such further non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

## **WINTER RELIABILITY PROGRAM FOR WINTER PERIODS PRIOR TO JUNE 1, 2018**

Ms. Allison DiGrande, Markets Committee Chair, referred the Committee to and summarized materials circulated and posted in advance of the meeting regarding revisions to Market Rule 1, Appendix K to implement a winter reliability program for winter periods prior to the June 1, 2018 implementation of the ISO's Pay-For-Performance (PFP) mechanism (Interim Program). She reviewed the procedural background that led to the proposals for an Interim

Program considered by the Markets Committee. She then explained that the ISO had proposed an Interim Program to include not only oil and LNG options available in the past winter's program, but to expand the program to provide compensation for any dispatchable (or self-scheduled) resource with on-site fuel storage, including nuclear, coal, biomass and certain hydro resources and to eliminate the past winter's program option for demand response (the ISO Proposal).

She reported that, at its June 2-3, 2015 meeting, the Markets Committee considered and voted for the ISO's recommended proposal and ultimately recommended a proposal (the NEPOOL Proposal) that contained two material amendments to the ISO's proposal. The first amendment modified the LNG component of the Interim Program to permit gas-fired Generator Assets to be eligible for compensation, but only for those assets that were capable of receiving pipeline gas *or* supplies of LNG (Exelon Amendment). The second amendment revised the ISO Proposal to include the core components of the 2014-15 Winter Reliability Program that would provide compensation for any oil inventory and LNG contract volumes that had not been used by the specified end of the winter period and that would continue a supplemental Demand Response Program, but would not expand the program to pay other resource types, like nuclear, coal and hydro. The Markets Committee supported the NEPOOL Proposal by a 84.51% Vote in favor. Following that vote, the ISO requested Markets Committee action on a modified ISO Proposal (with the Exelon Amendment included) ([the ISO Proposal](#)). The Markets Committee did not support the ISO Proposal, which garnered a 19.36% Vote in favor.

Mr. Gordon stated that an additional amendment considered, but not supported, by the Markets Committee would be presented, and that the ISO would seek a vote on the modified ISO

Proposal if the Participants Committee supported the NEPOOL Proposal as recommended by the Markets Committee. The following main motion was then duly made and seconded:

RESOLVED, that the Participants Committee supports revisions to Market Rule 1, Appendix K, as recommended by the Markets Committee and circulated to this Committee in advance of this meeting (NEPOOL Proposal), together with such non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

***Calpine Amendment***

The Committee then proceeded to consider a motion to amend the main motion, made by the Calpine representative, which was duly seconded, so as to change the compensation formula for the LNG component of the Winter Program so that Participating Generator Assets could be compensated for purchased LNG quantity (up to a specified cap), instead of unused LNG quantity (Calpine Amendment). ~~He~~[The Calpine representative](#) explained the underlying reasoning for the Calpine Amendment and emphasized the importance of LNG to winter reliability by way of anecdotal evidence and example. Without discussion, the Calpine Amendment was then voted and failed to pass with a 49.61% Vote in favor (Generation Sector – 10.28%; Transmission Sector – 8.56%; Supplier Sector – 11.85%; Alternative Resources Sector – 10.79%; Publicly Owned Entity Sector – 0%; End User Sector – 8.11%; and Provisional Member Group – 0.02%). (See Calpine Vote on Attachment 2)

***Vote on NEPOOL Proposal***

The unamended main motion (NEPOOL Proposal) was then voted and approved with an 87.10% Vote in favor (Generation Sector – 7.34%; Transmission Sector – 17.12%; Supplier

Sector – 14.01%;<sup>1</sup> Alternative Resources Sector – 14.37%; Publicly Owned Entity Sector – 17.12%; End User Sector – 17.12%; and Provisional Group Member – 0.02%). (See NEPOOL Proposal Vote on Attachment 2)

### ***Vote on ISO Proposal***

Following comments [from a number of members](#) expressing disappointment that the ISO was unable to ~~join in~~ support ~~of~~ the NEPOOL Proposal, the Committee, at the request of the ISO, voted but failed to support the ISO Proposal ~~(as modified by the Exelon Amendment)~~, with a 13.43% Vote in favor (Generation Sector – 11.41%; Transmission Sector – 0%; Supplier Sector – 2.02%; Alternative Resources Sector – 0%; Publicly Owned Entity Sector – 0%; End User Sector – 0%; and Provisional Group Member – 0%). (See ISO Proposal Vote on Attachment 2)

### **LITIGATION REPORT**

Mr. Doot referred the Committee to the June 24 Litigation Report that had been posted in advance of the session, noting the high level of activity notwithstanding the brief period of time covered since the June 4 Report was circulated. He encouraged anyone with comments or questions on the June 24 Report to contact NEPOOL Counsel.

### **COMMITTEE REPORTS**

Mr. Dell Orto announced that the next regularly-scheduled meetings of the Subcommittee would be held August 13, following the conclusion of the Markets Committee Summer Meeting, and August 26 (where, as noted earlier, the 2016 ISO and NESCOE budgets would be

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<sup>1</sup> The representative for Repsol and Vitol clarified that the votes for those Participants should have been registered as abstentions, rather than in favor. With those votes changed, the Supplier Sector share in favor was 14.01% and the NEPOOL Vote 87.10% in favor (rather than 14.49% and 87.58%, respectively, as announced immediately following the vote).

considered). Mr. Robert Stein, Reliability Committee Vice-Chair, reported that the Joint Summer Meeting of the Reliability and Transmission Committees would be held July 14-15 in Brewster, Massachusetts at The Ocean Edge Resort. At that meeting, Mr. Rotger, Transmission Committee Vice-Chair, indicated that there would be a presentation on the Regional Network Service rate for the 2015/16 Power Year, and encouraged those interested to attend. For the Markets Committee, Mr. Stacy Dimou, Vice-Chair, stated that the July 8-9 meeting would include consideration of further Coordinated Transaction Scheduling (CTS) changes and the Summer meeting would be held August 11-13 at Mill Falls at the Lake in Meredith, New Hampshire.

#### **OTHER BUSINESS**

Mr. Jeff Bentz, NESCOE, reported that the request for proposals regarding clean energy and transmission (New England Clean Energy RFP) would be filed with the Massachusetts Department of Public Utilities and the RI PUC later that day. Mr. Doot reported that the next Participants Committee meeting was scheduled to be held August 7 in Providence, Rhode Island.

There being no further business, the June 25 session and the Summer Meeting adjourned at 10:43 a.m.

Respectfully submitted,

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David T. Doot, Secretary

**MEMBERS AND ALTERNATES PARTICIPATING IN  
THE PARTICIPANTS COMMITTEE  
JUNE 23-25, 2015 SUMMER MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ashburnham Municipal Light Plant	Publicly Owned		Gary Will	
Belmont Municipal Light Department	Publicly Owned		Phil Smith	
Boylston Municipal Light Department	Publicly Owned		Gary Will	
BP Energy Company	Supplier			Nancy Chafetz
Brookfield Energy Marketing/Cross-Sound Cable (CSC)	Supplier	Aleks Mitreski	Nicolas Bosse	
Calpine Energy Services, L.P.	Supplier	John Flumerfelt	Brett Kruse	
Central Maine Power Company	Transmission	Eric Stinneford		
Chester Municipal Electric Light Department	Publicly Owned	Phil Smith		
Chicopee Municipal Lighting Plant	Publicly Owned		Gary Will	
Competitive Energy Services, LLC	Supplier			Glenn Poole
Concord Municipal Light Plant	Publicly Owned		Phil Smith	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut, State of, Office of Consumer Counsel	End User			Dave Thompson
Conservation Services Group (CSG)	AR		Doug Hurley (tel)	
Consolidated Edison Energy, Inc. (ConEd)	Supplier	Jeff Dannels		
Danvers Electric Division	Publicly Owned		Phil Smith	
Dominion Energy Marketing, Inc.	Generation	Jim Davis		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Elektrisola, Inc.	End User	Gus Fromuth		
Emera Maine	Transmission	Jeff Jones (tel)	Jose Rotger	Stacy Dimou
Energy America, LLC	Supplier	Ron Carrier		Nancy Chafetz
EnerNOC, Inc.	AR	Herb Healy		
Entergy Nuclear Power Marketing, LLC	Generation		Ken Dell Orto	Bill Fowler
Essential Power, LLC	Generation	M.Q. Riding	Bill Fowler	
Eversource Energy	Transmission	James Daly	Joseph Staszowski	
Exelon <a href="#">New England Holdings / Constellation Generation Company</a>	Supplier	Steve Kirk	Bill Fowler	
Fairchild Semiconductor Corporation	End User	Gus Fromuth		
Galt Power, Inc.	Supplier	Nancy Chafetz		
GDF SUEZ Energy Marketing NA, Inc.	Generation	Thomas Kaslow		
Generation Group Member	Generation	Dennis Duffy	Abby Krich (tel)	Bob Stein
Georgetown Municipal Light Department	Publicly Owned		Phil Smith	
Granite Ridge/Merrill Lynch	Supplier		Bill Fowler	
Groton Electric Light Department	Publicly Owned		Gary Will	
Groveland Electric Light Department	Publicly Owned		Phil Smith	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guibault	Bob Stein	
Harvard Dedicated Energy Limited	End User			Paul Peterson
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Phil Smith	
Holden Municipal Light Department	Publicly Owned		Gary Will	
Holyoke Gas & Electric Department	Publicly Owned			Gary Will
Hudson Light and Power Department	Publicly Owned		Gary Will	
Hull Municipal Lighting Plant	Publicly Owned		Gary Will	
Industrial Energy Consumer Group	End User	Don Sipe		<a href="#">Fred Plett</a>
Ipswich Municipal Light Department	Publicly Owned		Gary Will	
Jericho Power, LLC	AR		Phil Smith	
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		

**MEMBERS AND ALTERNATES PARTICIPATING IN  
THE PARTICIPANTS COMMITTEE  
JUNE 23-25, 2015 SUMMER MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Littleton (MA) Electric Light & Water Department	Publicly Owned		Phil Smith	
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kienny	<a href="#">David Mullett</a>
Maine Public Advocate Office	End User	Agnes Gormley	Tim Schneider	
Maine Skiing, Inc.	End User	Don Sipe		<a href="#">Fred Plett</a>
Mansfield Municipal Electric Department	Publicly Owned		Gary Will	
Marble River, LLC	Supplier	Seth Kaplan		Steve Garwood
Marblehead Municipal Light Department	Publicly Owned		Gary Will	
Massachusetts Attorney General's Office (MA AG)	End User	Fred Plett		
Mass. Development Finance Agency	Publicly Owned		Phil Smith	
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned	Gary Will		
Merrimac Municipal Light Department	Publicly Owned		Phil Smith	
Middleborough Gas and Electric Department	Publicly Owned		Gary Will	
Middleton Municipal Electric Department	Publicly Owned		Phil Smith	
MoArk, LLC	End User	Gus Fromuth		
National Grid	Transmission	Timothy Brennan	Timothy Martin	
New Hampshire Electric Cooperative (NHEC)	Publicly Owned		Steve Kaminski	Brian Forshaw
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
NRG Power Marketing, Inc.	Generation	Dave Cavanaugh		
Pascoag Utility District	Publicly Owned		Phil Smith	
Paxton Municipal Light Department	Publicly Owned		Gary Will	
Peabody Municipal Light Plant	Publicly Owned		Gary Will	
PowerOptions	End User			Paul Peterson
Princeton Municipal Light Department	Publicly Owned		Gary Will	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Repsol Energy North America Company	Supplier			Nancy Chafetz
Rowley Municipal Lighting Plant	Publicly Owned		Phil Smith	
Russell Municipal Light Dept	Publicly Owned		Gary Will	
Shipyard Brewing LLC	End User	Gus Fromuth		
Shrewsbury Electric & Cable Operations	Publicly Owned		Gary Will	
Small Load Response Group Member	AR	Doug Hurley (tel)		
Small Renewable Generation Group Member	AR	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned		Gary Will	
South Jersey Energy Company	Supplier			Nancy Chafetz
St. Anselm College	End User	Gus Fromuth		
Sterling Municipal Electric Light Department	Publicly Owned		Gary Will	
Stowe Electric Department	Publicly Owned		Phil Smith	
Sun Edison (First Wind Energy Marketing, Inc.)	AR	John Keene		Bob Stein
Tangent Energy Solutions	Provisional Member	Brad Swalwell (tel)		
Taunton Municipal Light Department	Publicly Owned		Phil Smith	
Templeton Municipal Lighting Plant	Publicly Owned		Gary Will	
Texas Retail, LLC	Supplier	Chris Hendrix		
The Energy Consortium	End User			Paul Peterson
TransCanada Power Marketing Ltd.	Generation			Dan Congel
Union of Concerned Scientists (UCS)	End User		Francis Pullaro	
United Illuminating Company, The	Transmission	Chris Bilcheck	Alan Trotta (tel)	
Utility Services, Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kienny		<a href="#">David Mullett</a>

**MEMBERS AND ALTERNATES PARTICIPATING IN  
THE PARTICIPANTS COMMITTEE  
JUNE 23-25, 2015 SUMMER MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Vermont Electric Power Company, Inc.	Transmission	Francis Etori	<a href="#">Mark Sciarotta</a>	
Vermont Energy Investment Corporation	AR		Doug Hurley (tel)	
Vermont Public Power Supply Authority	Publicly Owned	David Mullett		
Verso Maine Energy LLC	Generation	Glenn Poole		
Vitol Inc.	Supplier	<del>Joe Wadsworth</del>		<a href="#">Nancy Chafetz</a>
Wakefield Municipal Gas and Light Department	Publicly Owned		Gary Will	
Wallingford DPU Electric Division	Publicly Owned		Phil Smith	
Wellesley Municipal Light Plant	Publicly Owned		Phil Smith	
West Boylston Municipal Lighting Plant	Publicly Owned		Gary Will	
Westerly Hospital	End User		Gus Fromuth	
Westfield Gas & Electric Light Department	Publicly Owned		Gary Will	
ZTECH, LLC	End User		Gus Fromuth	

**VOTES TAKEN AT  
JUNE 23-25, 2015 PARTICIPANTS COMMITTEE SUMMER MEETING**

**TOTAL**

Sector/Group	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
GENERATION	10.28	7.34	11.41
TRANSMISSION	8.56	17.12	0.00
SUPPLIER	11.85	14.01	2.02
ALTERNATIVE RESOURCES	10.79	14.37	0.00
PUBLICLY OWNED ENTITY	0.00	17.12	0.00
END USER	8.11	17.12	0.00
PROVISIONAL MEMBERS	<u>0.02</u>	<u>0.02</u>	<u>0.00</u>
<b>% IN FAVOR</b>	<b>49.61</b>	<b>87.10</b>	<b>13.43</b>

**GENERATION SECTOR**

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Dominion Energy Marketing, Inc.	O	O	F
Entergy Nuclear Power Marketing	A	O	F
Essential Power, LLC	F	F	A
GDF SUEZ Energy Marketing NA	F	O	F
Generation Group Member	A	A	A
NextEra Energy Resources, LLC	O	O	F
NRG Power Marketing, LLC	A	A	A
TransCanada Power Marketing	A	F	O
Verso Maine Energy LLC	F	F	O
IN FAVOR (F)	3	3	4
OPPOSED (O)	2	4	2
TOTAL VOTES	5	7	6
ABSTENTIONS (A)	4	2	3

**TRANSMISSION SECTOR**

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Central Maine Power Company	A	F	A
Emera Maine	F	S	S
<i>Emera Maine</i>	-	F	O
<i>Emera Energy Services Subsidiaries</i>	-	A	A
Eversource Energy	O	F	A
National Grid	O	F	A
The United Illuminating Company	F	F	O
Vermont Electric Power Company	A	F	O
IN FAVOR (F)	2	5.5	0
OPPOSED	2	0	2.5
TOTAL VOTES	4	5.5	2.5
ABSTENTIONS (A)	2	0.5	3.5

**ALTERNATIVE RESOURCES SECTOR**

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
<b>Renewable Generation Sub-Sector</b>			
Jericho Power LLC	O	F	O
SunEdison (First Wind)	A	A	O
Small RG Group Member	F	F	O
<b>Distributed Generation Sub-Sector</b>			
Conservation Services Group	A	F	O
<b>Load Response Sub-Sector</b>			
EnerNOC, Inc.	F	F	O
VT Energy Investment Corp.	A	F	O
Small LR Group Member	A	F	O
IN FAVOR (F)	2	6	0
OPPOSED	1	0	7
TOTAL VOTES	3	6	7
ABSTENTIONS (A)	4	1	0

**SUPPLIER SECTOR**

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
BP Energy Company	A	F	O
Brookfield Energy Marketing/CSC	O	O	O
Calpine Energy Services	F	F	O
Competitive Energy Services, LLC	F	F	O
Consolidated Edison Energy, Inc.	F	A	O
DTE Energy Trading, Inc.	O	F	O
Dynegy Marketing and Trade, LLC	F	O	F
Energy America, LLC	O	F	O
Exelon Generation Company	F	A	A
Galt Power, Inc.	A	F	O
Granite Ridge/ Merrill Lynch Commodities	F	A	F
H.Q. Energy Services (U.S.) Inc.	A	A	A
LIPA (Long Island Power Authority)	A	F	O
Marble River, LLC	A	A	O
PSEG Energy Resources & Trade	F	F	O
Repsol Energy North America	F	A	O
South Jersey Energy Company	O	F	O
Texas Retail, LLC	F	A	O
Vitol Inc.	A	A	O
IN FAVOR (F)	9	9	2
OPPOSED	4	2	15
TOTAL VOTES	13	11	17
ABSTENTIONS (A)	6	8	2

**VOTES TAKEN AT  
JUNE 23-25, 2015 PARTICIPANTS COMMITTEE SUMMER MEETING**

**ND USER SECTOR**

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Conn. Office of Consumer Counsel	O	F	O
Elektrisola, Inc.	F	F	O
Fairchild Semiconductor Corp.	F	F	O
Harvard Dedicated Energy Limited	O	F	O
High Liner Foods (USA) Inc.	F	F	O
Industrial Energy Consumer Group	O	F	O
Maine Public Advocate Office	O	F	O
Maine Skiing, Inc.	O	F	O
Mass. Attorney General's Office	O	F	O
MoArk, LLC	F	F	O
NH Office of Consumer Advocate	O	F	O
PowerOptions, Inc.	O	F	O
St. Anselm College	F	F	O
Shipyards Brewing Co., LLC	F	F	O
The Energy Consortium	O	F	O
Union of Concerned Scientists	F	F	O
Utility Services Inc.	O	F	O
Westerly Hospital	F	F	O
Z-TECH, LLC	F	F	O
IN FAVOR (F)	9	19	0
OPPOSED	10	0	19
TOTAL VOTES	19	19	19
ABSTENTIONS (A)	0	0	0

**PUBLICLY OWNED ENTITY SECTOR**

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Ashburnham Municipal Light Plant	O	F	O
Boylston Municipal Light Dep't	O	F	O
Belmont Municipal Light Dep't	O	F	O
Chester Municipal Light Dep't	O	F	O
Chicopee Municipal Lighting Plant	O	F	O
Concord Municipal Light Plant	O	F	O
Conn. Mun. Electric Energy Coop.	O	F	O
Danvers Electric Division	O	F	O
Georgetown Municipal Light Dep't	O	F	O
Groton Electric Light Department	O	F	O
Groveland Electric Light Dep't	O	F	O
Hingham Municipal Lighting Plant	O	F	O
Holden Municipal Light Dep't	O	F	O
Holyoke Gas & Electric Dep't	O	F	O
Hudson Light and Power Dep't	O	F	O
Hull Municipal Lighting Plant	O	F	O
Ipswich Municipal Light Dep't	O	F	O

**PUBLICLY OWNED ENTITY SECTOR (cont.)**

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Littleton (MA) Electric Light Dep't	O	F	O
Littleton (NH) Water & Light Dep't	O	F	O
Mansfield Municipal Electric Dep't	O	F	O
Marblehead Municipal Light Dep't	O	F	O
Mass. Development Finance Agc'y	O	F	O
Mass. Mun. Wholesale. Elec. Co.	O	F	O
Merrimac Municipal Light Dep't	O	F	O
Middleborough Gas & Elec. Dep't	O	F	O
Middleton Municipal Electric Dep't	O	F	O
New Hampshire Electric Coop.	O	F	O
Pascoag Utility District	O	F	O
Paxton Municipal Light Dep't	O	F	O
Peabody Municipal Light Plant	O	F	O
Princeton Municipal Light Dep't	O	F	O
Rowley Municipal Lighting Plant	O	F	O
Russell Municipal Light Dep't	O	F	O
Shrewsbury's Elec. & Cable Ops.	O	F	O
South Hadley Electric Light Dep't	O	F	O
Sterling Mun. Elec. Light Dep't	O	F	O
Stowe (VT) Electric Department	O	F	O
Taunton Municipal Lighting Plant	O	F	O
Templeton Mun. Lighting Plant	O	F	O
VT Electric Cooperative	O	F	O
VT Public Power Supply Authority	O	F	O
Wakefield Mun. Gas & Light Dep't	O	F	O
Wallingford (CT) Div. Pub. Utils.	O	F	O
Wellesley Municipal Light Plant	O	F	O
West Boylston Mun. Lighting Plant	O	F	O
Westfield Gas & Elec. Light Dep't	O	F	O
IN FAVOR (F)	0	46	0
OPPOSED	46	0	46
TOTAL VOTES	46	46	46
ABSTENTIONS (A)	0	0	0

**PROVISIONAL MEMBERS**

Participant Name	Calpine Amend	NEPOOL Proposal	ISO-NE Proposal
Tangent Energy Solutions, Inc.	F	F	A
IN FAVOR (F)	1	1	0
OPPOSED	0	0	0
TOTAL VOTES	1	1	0
ABSTENTIONS (A)	0	0	1

## CONSENT AGENDA

### I. Coordinated Transaction Scheduling (CTS)-related Technical Committee actions

From the notice of actions of the May 26, 2015 *Transmission Committee*<sup>1</sup> meeting, dated May 26, 2015, which has been previously circulated:

#### 1. **CTS Revisions to ISO Tariff §§ I and II**

Support revisions to Sections I and II of the ISO Tariff relating to the implementation of CTS, as recommended by the Transmission Committee at its May 26, 2015 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Transmission Committee may approve.

The motion to recommend Participants Committee support was approved unanimously, with two abstentions noted in the Supplier Sector and 38 abstentions noted in the Publicly Owned Entity Sector.

From the notice of actions of the June 3, 2015 *Reliability Committee*<sup>2</sup> meeting, dated June 4, 2015, which has been previously circulated:

#### 2. **CTS Revisions to ISO-NE/NYISO Coordination Agreement (Including Schedule D)**

Support revisions to the ISO-NE/NYISO Coordination Agreement (including Schedule D of the Agreement) relating to the implementation of CTS, as recommended by the Reliability Committee at its June 3, 2015 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously, with 1 abstention in the Supplier Sector and 37 abstentions in the Publicly Owned Sector noted.

From the notice of actions of the *Reliability Committee*<sup>2</sup> at the July 14-15, 2015 RC/TC summer meeting, dated July 16, 2015, which has been previously circulated:

#### 3. **Further CTS Revisions to ISO-NE/NYISO Coordination Agreement Schedule D**

Support revisions to Schedule D of the ISO-NE/NYISO Coordination Agreement relating to CTS implementation, as recommended by the Reliability Committee at the July 13-14, 2015 RC/TC summer meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

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<sup>1</sup> Transmission Committee Notices of Actions are posted on the ISO website at: <http://iso-ne.com/committees/transmission/transmission-committee>.

<sup>2</sup> Reliability Committee Notices of Actions are posted on the ISO website at: <http://iso-ne.com/committees/reliability/reliability-committee>.

CONSENT AGENDA (cont.)

From the notice of actions of the May 5-6, 2015 *Markets Committee*<sup>3</sup> meeting, dated May 7, 2015, which has been previously circulated:

**4. CTS Revisions to Market Rule 1 (MR1) and MR1 Appendix F**

Support conforming revisions to Market Rule 1 and Appendix F to Market Rule 1 relating to the implementation of CTS, as recommended by the Markets Committee at its May 5-6, 2015 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously, with one abstention noted in each of the Generation, Supplier and AR Sectors.

From the notice of actions of the *Markets Committee*<sup>3</sup> at its June 3 joint meeting with the Reliability Committee, dated June 4, 2015, which has been previously circulated:

**5. CTS Revisions to Tariff § I.2.2 and ISO-NE/NYISO Coordination Agreement Schedule D**

Support Schedule D of the ISO-NE/NYISO Coordination Agreement and the revision to Tariff Section I.2.2 (Definitions) relating to the implementation of CTS, as recommended by the Markets Committee at its June 3, 2015 joint meeting with the Reliability Committee, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously, with 24 abstention noted in the Publicly Owned Entity Sector.

From the notice of actions of the July 9, 2015 *Markets Committee*<sup>3</sup> meeting, dated July 10, 2015, which has been previously circulated:

**6. Further CTS Revisions to ISO-NE/NYISO Coordination Agreement Schedule D**

Support revisions to Schedule D of the ISO-NE/NYISO Coordination Agreement relating to CTS implementation, as recommended by the Markets Committee at its July 9, 2015 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously, with one abstention noted in the Supplier Sector and two abstentions noted in the AR Sector.

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<sup>3</sup> Markets Committee Notices of Actions are posted on the ISO website at: <http://www.iso-ne.com/committees/markets/markets-committee>.

CONSENT AGENDA (cont.)

**II. Other Technical Committee Actions**

From the notice of actions of the July 22, 2015 *Markets Committee*<sup>3</sup> meeting, dated July 22, 2015, which has been previously circulated:

**7. Market Rule 1 Revisions (Compliance Changes to Remove Static De-List Bid Changes from IMM FCM Mitigation Package)**

Support revisions to Market Rule 1 that remove FERC-rejected changes regarding the ability of capacity suppliers to revise their Static De-List Bids or “convert” de-list bids into Non-Price Retirement Requests in response to the FERC’s June 30, 2015 order in Docket No. ER15-1650, as recommended by the Markets Committee at its July 22, 2015 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.<sup>4</sup>

From the notice of actions of the *Reliability Committee*<sup>2</sup> at the July 14-15, 2015 RC/TC summer meeting, dated July 16, 2015, which has been previously circulated:

**8. PP-5-6 Revisions (ETU Additions & Additional Clarifications)**

Support the revisions to ISO Planning Procedure No. 5-6 (PP5-6) (Scope of Interconnection Studies for Generation and Elective Transmission Upgrades), which address Elective Transmission Upgrades (ETU) and reflect additional clarifications, as recommended by the Reliability Committee at the July 14-15, 2015 RC/TC summer meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

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<sup>4</sup> Due to the 30-day compliance requirement in the June 30 order, the ISO is required to file compliance changes ahead of Participants Committee action on this item. While the Markets Committee’s recommendation will be reflected in the ISO’s July 30 compliance filing, NEPOOL will not be in a position to join in or support that filing prior to completion of the Participant Processes. The results of the Participants Committee action on this item will be reflected in NEPOOL comments to the FERC in response to that filing.

CONSENT AGENDA (cont.)

**9. OP-14 Appendix F Revisions (Order 764 Conforming Changes; new Section 3.5)**

Support the revisions to Appendix F to ISO Operating Procedure (OP) No. 14 (Wind Plant Operator Guide), which among other things conforms the Appendix with the requirements of FERC Order 764, adds a new Section 3.5 (Plant Frequency Response) and makes additional corrections and clarifications, as recommended by the Reliability Committee at the July 14-15, 2015 RC/TC summer meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

**10. OP-21 Appendix A Revisions**

Support the revisions to Appendix A to OP-21 (Generator Fuel Inventory Survey), as recommended by the Reliability Committee at the July 14-15, 2015 RC/TC summer meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

**11. OP-17 Appendix C Revisions (Updates to Table 1; Transmission Owners/Market Participant Define Term Replacement)**

Support the revisions to Appendix C to OP-17 (Instructions for the ISO Power Factor Survey), which replace each occurrence of “Market Participant” with “Transmission Owners/Market Participants” and updates Table 1, as recommended by the Reliability Committee at the July 14-15, 2015 RC/TC summer meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

CONSENT AGENDA (cont.)

From the notice of actions of the *Transmission Committee*<sup>1</sup> at the July 14-15 RC/TC summer meeting, dated July 14, 2015, which has been previously circulated:

**12. Schedule 24 Revisions (Further 676-H Compliance Changes)**

Support revisions to Schedule 24 of Section II of the ISO Tariff in response to the FERC's May 19, 2015 order on the ISO's Order No. 676-H compliance filing, as recommended by the Transmission Committee at its July 14, 2015 summer meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Transmission Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.<sup>5</sup>

**13. Attachment K and Schedule 25 Revisions  
(Order 1000 and ETU Tariff Versioning True-up)**

Support revisions to Attachment K and Schedule 25 of Section II of the ISO Tariff to true-up Tariff versioning associated with Order 1000 compliance and Elective Transmission Upgrades (ETU) filings, as recommended by the Transmission Committee at its July 14, 2015 summer meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Transmission Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

From the notice of actions of the July 9, 2015 *Markets Committee*<sup>3</sup> meeting, dated July 10, 2015, which has been previously circulated:

**14. Manuals M-28 and M-RPA Revisions (Ownership Share Change Timing)**

Support revisions to Manuals M-28 and M-RPA to implement an ownership share timing revision within the Asset Registration Process and associated clean-up changes, as recommended by the Markets Committee at its July 9, 2015 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

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<sup>5</sup> Due to the 60-day compliance filing requirement in the May 19 order, the ISO filed the Schedule 24 revisions recommended by the Transmission Committee on July 20, 2015 in FERC Docket No. ER15-519-001. The results of Transmission Committee vote were reflected in the ISO's compliance filing. The results of the Participants Committee action on this item will be reflected in NEPOOL comments to the FERC in response to that filing.

CONSENT AGENDA (cont.)

**15. Market Rule 1 and ISO Tariff § I.2.2 Revisions (FCM System Sloped Demand Curve Reconfiguration Auction Changes)**

Support revisions to Market Rule 1 and Tariff Section I.2.2 to modify the design of reconfiguration auctions to be consistent with the FCM system sloped demand curve, as recommended by the Markets Committee at its July 9, 2015 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

The motion to recommend Participants Committee support was approved unanimously, with one abstention noted in the Supplier Sector.

From the notice of actions of the June 16, 2015 *Reliability Committee*<sup>2</sup> meeting, dated June 16, 2015, which has been previously circulated:

**16. Market Rule I, § III.1.5 Revisions (Reactive Capability Auditing)**

Support revisions to Market Rule I, Section III.1.5 (Resource Auditing), as recommended by the Reliability Committee at its June 16, 2015 meeting, with such further non-substantive changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

## MEMORANDUM

**TO:** NEPOOL Participants Committee Members and Alternates  
**FROM:** Paul N. Belval, NEPOOL Counsel  
**DATE:** July 31, 2015  
**RE:** ISO New England Self-Funding Tariff – CTS-Related Changes

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The Participants Committee will be asked at its August 7 meeting to support changes to the ISO Self-Funding Tariff related to the Coordinated Transaction Scheduling (CTS) changes to the ISO Tariff and Market Rules that are on the Consent Agenda for that meeting. The changes to the ISO Self-Funding Tariff exclude Coordinated External Transactions from the calculations of charges due under Schedules 1, 2 and 3. The proposed changes (which have been included and posted with this memorandum) are contemplated by the items that are on the Consent Agenda.

The changes to the ISO Self-Funding Tariff were discussed by the NEPOOL Budget and Finance Subcommittee on its May 13 teleconference, and no one on that teleconference objected to the changes.

The following form of resolution could be used for Participants Committee action:

RESOLVED, that the Participants Committee supports the changes to the ISO Self-Funding Tariff relating to Coordinated Transaction Scheduling, as circulated to the Committee and discussed at this meeting, together with [any changes agreed to at this meeting and ]such further non-substantive changes as the Chief Financial Officer of ISO New England and the Chairman of the Budget & Finance Subcommittee may approve.

**SECTION IV.A**  
**RECOVERY OF ISO ADMINISTRATIVE EXPENSES**

## **Schedule 1**

### **Scheduling, System Control and Dispatch Service**

Scheduling, System Control and Dispatch Service (“Scheduling Service”) is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. For regional transmission service under the Tariff, Scheduling Service is an Ancillary Service that can be provided only by the ISO. All Transmission Customers must be Customers for Scheduling Service under this Tariff and purchase this Service from the ISO. The ISO’s charges stated herein for Scheduling Service are based on the expenses incurred by the ISO in providing this Service. In addition, the ISO acts as a billing agent for the operators of the Local Control Centers and certain Market Participants in order to collect expenses incurred in providing this Service pursuant to this Schedule 1.

The ISO’s expenses are based on the functions and activities required to provide this Service and include, but are not limited to:

- Processing and implementation of requests for regional transmission service, including support of the OASIS node;
- Coordination of transmission system operation (including administration of reactive power requirements under Schedule 2 of Section II of the Tariff) and implementation of necessary control actions by the ISO and support for these functions;
- Billing associated with regional transmission services provided under the Tariff;
- Transmission system planning which supports this Service; and
- Administrative costs associated with the aforementioned functions.

For the ISO’s expenses in providing transmission-related Scheduling Service:

(A) each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of \$0.15570 per kilowatt month times its Monthly Regional Network Load for that month.

(B) each Customer that is a Transmission Customer receiving Through or Out Service shall pay each month, in arrears, an amount equal to the product of the Transmission Customer’s highest amount of Reserved Capacity (expressed in kilowatts) for an hour for each transaction, [other than a Coordinated](#)

[External Transaction, that is](#) scheduled to occur during the month as Through or Out Service multiplied by \$0.00021 per kilowatt for each hour of service.

Schedule 1 revenues collected from Through or Out Service customers shall be credited to each Network Customer receiving Regional Network Service that month in proportion to each Network Customer's Monthly Regional Network Load in that month.

Non-Market Participant FTR fees and any portions of Long Lead Facility deposits collected by the ISO under Schedule 22 and Schedule 25 of Section II of the Tariff that become non-refundable will be credited to Schedule 1 Revenue Requirements and will be included in the Schedule 1 true-up calculations.

All general terms and conditions of the Tariff apply to this Service.

## Schedule 2 Energy Administration Service

Energy Administration Service (“EAS”) is the Service provided by the ISO to administer the Energy Market.

The ISO’s expenses are based on the functions required to provide EAS and include, but are not limited to:

- Core operation of the Energy Market;
- Generation and demand dispatch related to the Energy Market;
- Energy accounting;
- Loss determination and allocation;
- Billing preparation;
- Market power monitoring and mitigation for the Energy Market;
- Sanctions activities;
- Operation of FTR auctions;
- Market assessment and reports; and
- Formulation of additional market rules and proposals to modify existing rules.

Each Market Participant that has an account for Energy that is settled by the ISO for the current month shall pay each month an amount based on Energy Transaction Units (Energy TUs), Increment Offers, Decrement Bids, Volumetric Measures, submitted FTR auction bids, and cleared FTR auction bids.

Energy TU Based Charges: [For purposes of this Schedule 2, Energy TUs shall be calculated without reference to contributions from Coordinated External Transactions.](#) Each Customer that has, during a month, incurred Energy TUs exceeding zero shall pay an amount, in arrears, equal to the sum of the products of:

- (1) \$0.65101 times the Customer’s first 12,500 Energy TUs for that month; plus
- (2) \$0.59182 times the amount of Energy TUs that exceed 12,500 but are less than or equal to 39,500; plus

- (3) \$0.53264 times the amount of Energy TUs that exceed 39,500.

Charges Based on Increment Offers and Decrement Bids: Each Customer submitting Increment Offers and/or Decrement Bids shall pay, in arrears, amounts equal to:

- (1) \$0.00500 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month; plus
- (2) \$0.06000 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month that clear in the Day-Ahead Energy Market.

Volumetric Measure Based Charges: A Customer shall be considered an EAS VM Customer if the sum of Monthly Real-Time Load Obligation and Monthly Real-Time Generation Obligation (measured in megawatthours, MWh and excluding Coordinated External Transactions) assessed to that Customer during the month exceeds zero (0), in which case, the total EAS VM charges for that Customer shall be equal to the sum of:

- (1) Monthly Real-Time Load Obligation (MWh), excluding Monthly Real-Time Load Obligation associated with Coordinated External Transactions; and
- (2) Monthly Real-Time Generation Obligation (MWh); provided, however, that Monthly Real-Time Generation Obligation associated with energy imported into the New England Control Area by Bangor Hydro-Electric Company across the New Brunswick ties shall be excluded (up to 300 MW) for billing and rate calculation purposes from EAS VMs, and provided further that Monthly Real-Time Generation Obligation associated with Coordinated External Transactions shall be excluded.

Subject to the foregoing, each Market Participant that is identified as an EAS VM Customer for that month shall pay an amount, in arrears, based on total EAS VM, equal to:

- (a) \$0.25517 per MWh for the first 250,000 MWh of EAS VM for that month; plus

- (b) \$0.23197 per MWh for each VM that exceeds 250,000 EAS VM but is less than or equal to 1,500,000 MWh for that month; plus
- (c) \$0.20877 per MWh for each EAS VM in excess of 1,500,000 MWh for that month.

Charges Based on Submitted and Cleared FTR Bids: Each Customer submitting FTR auction bids shall pay, in arrears, amounts equal to:

- (1) \$.85853 times the number of bids submitted by the Customer into any FTR auctions held for that month; plus
- (2) \$.85853 times the number of bids submitted by the Customer into any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction); plus
- (3) \$1.21377 times the number of bids submitted by the Customer during that month that clear any FTR auctions held for that month; plus
- (4) \$1.21377 times the number of bids submitted by the Customer that clear any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction).

### **Schedule 3**

#### **Reliability Administration Service**

Reliability Administration Service (“RAS”) is the Service provided by the ISO to administer the Reliability Markets (and facilitate reliability-associated transactions and arrangements) in accordance with the Tariff and the corresponding rules promulgated thereunder, and to provide other reliability and informational services. The Reliability Markets are also a means by which certain Ancillary Services are obtained under Section II of the Tariff. Each Customer must enter into a Service Agreement.

The ISO’s administrative expenses are based on the functions required to provide this Service and include, but are not limited to:

- Generation and demand dispatch associated with Reliability Markets;
- Reliability Markets accounting;
- Billing preparation;
- The ISO generation emissions analysis;
- Risk profile updates;
- Triennial review of resource adequacy;
- Studies and qualification of resources under Forward Capacity Market;
- Preparation of regional reports and load forecasts and profiles (Capacity, Energy, Load and Transmission reports; reports to the Energy Information Administration (EIA) of the United States Department of Energy; reports to the North American Electric Reliability Corporation; Regional System Plan);
- Support of power supply, environmental and market reliability planning activities;
- Market power monitoring, mitigation and assessment for the Reliability Markets;
- Formulation of additional market rules and proposals to modify existing rules.

(A) Each Transmission Customer taking Through or Out Service that is not a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, a RAS fee equal to the product of \$3.02 times the number of hourly Through or Out reservations made for that month.

(B) Each Customer that is a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, an amount equal to the product of \$0.18763 per kilowatt month times the Market Participant's Real-Time NCP Load Obligation (measured in kilowatts) for that month.

(C) For Exports [other than Coordinated External Transactions](#), each RAS Customer shall pay each month, in arrears, an amount equal to \$0.37 per MWh per Export, where MWh represents the hourly scheduled MWs of associated Export.

In order to preserve the settlement approved in Docket No. ER01-316, Market Participants engaging in "through" transactions using Through or Out Service will not be deemed to have a Real-Time Load Obligation on account of those transactions.

Charges collected under Schedule 3 for RAS do not include any amounts paid by the ISO on behalf of the Market Participants to purchase emergency power.

Charges collected under Schedule 3 for RAS do not include the recovery of costs associated with disclosure or tracking obligations. If one or more states require Market Participants to undertake such activity the ISO will separately charge the expenses associated with such obligations.

All general terms and conditions of the Tariff apply to this Service.



# Coordinated Transaction Scheduling: Self and Capital Funding Tariff

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*Modifications to ISO Self-Funding Tariff to support  
Coordinated Transaction Scheduling (CTS)*



# The CTS design eliminates costs on transactions between NY and NE

- The CTS design\* objectives include elimination of the cross-border transaction costs for inter-regional energy trading between New England and New York
- This will lower barriers to economically efficient interchange
  - ISO-NE explains the inefficiency implications of the ISO Self-Funding Tariff transaction costs in a joint white paper with NYISO and in posted Markets Committee materials:
    - White paper at II-20: [http://www.iso-ne.com/static-assets/documents/pubs/whtpprs/iris\\_white\\_paper.pdf](http://www.iso-ne.com/static-assets/documents/pubs/whtpprs/iris_white_paper.pdf)
    - March 7, 2011 presentation at 65: [http://www.iso-ne.com/static-assets/documents/committees/comm\\_wkgrps/mrkets\\_comm/mrkets/mtrls/2011/mar72011/a1\\_a8\\_iso\\_ne\\_nyiso\\_presentation\\_03\\_07\\_11.pdf](http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/mrkets_comm/mrkets/mtrls/2011/mar72011/a1_a8_iso_ne_nyiso_presentation_03_07_11.pdf)

\*CTS Tariff Revisions (ER12-1155-000): [http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2012/feb/er12\\_1155\\_000\\_02\\_24\\_2012\\_cts\\_filing.pdf](http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2012/feb/er12_1155_000_02_24_2012_cts_filing.pdf)

# Review of Materials and Schedule

- Reviewed at previous NEPOOL B&F meetings in May 2012 and May 2014
- May 2015: review Coordination Agreement with RC and Schedule D of Coordination Agreement with both RC and MC
- June 2015: Technical Committee votes expected no later than June
- NPC vote on CTS expected no later than September 2015
- October 2015: 2016 Budget and Self-Funding Tariff vote by NPC including CTS related changes impacting the Section IV.A for the Self-Funding Tariff.

# The CTS design requires a number of changes to the ISO Self-Funding Tariff

- Section IV.A Schedule 1 (Scheduling Service)
  - TOUT Service charges
- Section IV.A Schedule 2 (EAS)
  - TU-based and VM-based charges
- Section IV.A Schedule 3 (RAS)
  - Export charges
- Section IV.A Schedule 4 (Commission Annual Charges)
  - Not impacted
- Section IV.A Schedule 5 (NESCOE)
  - Not impacted

# Magnitude of ISO Self-Funding Collections by Schedule

**Note:** the following estimates of “CTS Contributions” to the ISO Self-Funding Tariff schedules are the historical monthly average volumes for external transactions at the New York Northern AC location between January, 2012 and December, 2014 that would be ineligible for charges under CTS.

Schedule	Pool Total Charge \$ (monthly average)	CTS Contribution (monthly average)	CTS % of Pool Charge \$ (monthly average)
Schedule 1	\$2,948,960	\$31,992	1.1%
Schedule 2	\$5,538,949	\$157,164*	2.8%
Schedule 3	\$3,938,355	\$55,461	1.4%

\* The estimate was determined using the highest cost block rates for Schedule 2 charge types.

# Magnitude of ISO Self-Funding Collections by Schedule and Charge Type

**Note:** the following estimates of “CTS Contributions” to the ISO Self-Funding Tariff schedules are the historical monthly average volumes for external transactions at the New York Northern AC location between January, 2012 and December, 2014 that would be ineligible for charges under CTS.

Schedule Charge Type	Pool Total Charge Basis (monthly average)	CTS Contribution (monthly average)	Pool Total Charge \$ (monthly average)	CTS Contribution (monthly average)	CTS % of Pool Charge \$ (monthly average)
Schedule 1 TOUT	459,458 MWh	156,683 MWh	\$93,899	\$31,992	34.1%
Schedule 2 Energy TU-based	1,408,729	45,106	\$939,465	\$31,134*	3.3%
Schedule 2 VM-based	22,386,659 MWh	577,415 MWh	\$5,039,907	\$126,030*	2.5%
Schedule 3 Export	454,211 MWh	156,586 MWh	\$160,815	\$55,461	34.5%

\* The estimate was determined using the highest cost block rate.

# Magnitude of ISO Self-Funding Collections and Rate Impact

**Note:** the following estimates “CTS Contributions” to the overall ISO Self-Funding Tariff based on 2015 FERC filed rates using historical average volumes for external transactions at the New York Northern AC location between January, 2012 and December, 2014 that would be ineligible for charges under CTS. This also illustrates the impact the elimination of “CTS Contributions” would have on each schedule’s rates for 2015 if CTS was in effect.

Schedule Charge Type	2015 Filed Revenue Requirement	2015 Annual CTS Contribution based on 2012-2014 average volume	2015 Tariff Filed Rate	2015 Rate if CTS was in effect	Rate Change
Schedule 1	\$37,940,742	\$292,747	\$0.15570 /KWh-mo.	\$0.15691 /KWh-mo.	\$0.00121 /KWh-mo.
Sch. 2 Virtual & FTR TU’s	\$633,391	\$0	N/A	N/A	N/A
Schedule 2 Energy TU-Based (1)	\$11,061,515	\$352,373	\$0.62749 TU-hour	\$0.64737 TU-hour	\$0.01988 TU-hour
Schedule 2 VM-Based (1)	\$66,271,126	\$1,768,068	\$0.24363 /MWh	\$0.24999 /MWh	\$0.00637 /MWh
Schedule 3 RT-NCP Load Obligation (2)	\$51,067,436	\$0	\$0.18763 /KWh-mo.	\$0.19019 /KWh-mo.	\$0.00256 /KWh-mo.
Schedule 3 Export (2)	\$1,562,827	\$695,242	\$0.37 /MWh	\$0.37 /MWh	\$0.00 /MWh
<b>Total</b>	<b>\$168,537,037</b>	<b>\$3,108,430</b>			

- (1) Schedule 2 Energy TU’s and Volumetric charges utilize a declining block rate schedule. Amounts shown represent a blended rate for each schedule for this analysis.
- (2) Schedule 3 Export transactions are based on a fixed rate, therefore, any change in volume will result in a change in the revenue requirement and rate for Schedule 3 Real-Time Non-Coincident Peak Load Obligation. The \$695,242 calculated for this analysis would be included in Schedule 3 RT-NCP Load Obligation.

# Summary

- All costs allocated to CTS transactions scheduled over the New York North interface through the ISO Self-Funding Tariff will be eliminated
- CTS implementation is planned for December 2015
- The ISO is anticipating filing changes at the FERC to the Transmission, Markets, and Services Tariff in September 2015, including Section IV.A for the Self-Funding Tariff. The filing changes will include a new defined term “*Coordinated External Transaction*” representing those transactions that would be ineligible for charges under CTS.
- The ISO will factor the exclusion of CTS transactions into the 2016 rates that will be submitted with the 2016 Budget/ISO Self-Funding Tariff filing with the FERC in October 2015.

## **Summary of ISO New England Board and Committee Meetings**

### **August 7, 2015 Participants Committee Meeting**

Since the last update, the Markets Committee met on June 9 in Newport, Rhode Island. The Nominating and Governance Committee, Compensation and Human Resources Committee, the Markets Committee, the System Planning and Reliability Committee, and the Board of Directors met in Stowe, Vermont on June 22. In addition, the Markets Committee also met on July 16 by teleconference.

**The Markets Committee** met on June 9 to review a draft of the External Market Monitor's Annual Report. There was a general discussion concerning recommendations for market changes, and projects underway to address those recommendations.

On June 22, the Committee received reports on market monitoring, mitigation and reliability costs from both the External Market Monitor and Internal Market Monitor, and focused on the relationship between fuel prices and energy market prices, as well as the payment of Net Commitment Period Compensation. The Committee also reviewed the two monitors' quarterly reports. Next, the Committee discussed proposed rule changes to address uneconomic retirements in the Forward Capacity Market, and considered the stakeholder process for the proposed rule changes, and the role of the FERC in resolving disputes.

The Committee also met by teleconference on July 16, and considered reports on market monitoring, mitigation and reliability costs. The Committee reviewed the factors contributing to the low energy market prices that occurred during June. Next, the Committee received an update on the status of efforts to make several changes to the NCPC rules and the stakeholder process to address the NCPC changes recommended by the External Market Monitor, which are scheduled to be voted by stakeholders and filed in October. The Committee received a summary of the capacity market mitigation-related changes that were addressed in a recent FERC order, and discussed certain aspects of the order that relate to the options available to permanently retire resources from the capacity market. Finally, the Committee conducted its biennial review of the committee charter to confirm compliance.

**The Nominating and Governance Committee** convened on June 22 and discussed the evaluations of Board and Committee performance. The Committee examined various points to highlight in its report to the Board.

**The Compensation and Human Resources Committee** met in executive session to review the Company's succession management plans. The Committee also conducted its annual assessment of the risks within its purview and agreed that the primary risks relate to succession planning and finding and retaining the employees needed to fulfill the Company's mission.

**The System Planning and Reliability Committee** reviewed the Executive Summary of the 2015 Regional System Plan and also discussed plans for the Regional System Plan public meeting. Next, the Committee received an update on FERC Order 1000 compliance and the ongoing work with stakeholders related to the implementation of new provisions for both regional and interregional planning.

**The Board of Directors** received reports from the Committees and also reviewed the Company's Form 990 for 2014, which will be filed with the Internal Revenue Service later this year. The Board then considered topics raised in advance by participants for discussion at the sector meetings to be held the next day. Finally, the Board considered the results of its evaluation.

# NEPOOL Participants Committee Report

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*August 2015*



Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER



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# Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy Market Value was \$337M over the period, up \$92M from June 2015 and down \$174M from July 2014
  - July natural gas prices over the period were 12.5% higher than June 2015 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were 30% higher than June 2015 averages
  - Average July 2015 natural gas prices and RT Hub LMPs over the period were down 39% and 27%, respectively, from July 2014 averages
- Average DA cleared physical energy in the peak hours as percent of forecasted load was 99.1% during July, up from 97.9% during June

**All data through July 29 (RT NCPC through July 28) unless otherwise noted.**

Underlying natural gas data furnished by:



\*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market



# Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - July NCPC payments totaled \$4.3M, down \$5.1M from June and down \$5.4M from July 2014
  - First Contingency payments totaled \$4.1M, down \$593K from June
    - \$3.9M paid to internal resources, down \$547K from June
      - \$351K charged to DALO, \$3.6M to RT Deviations
    - \$118K paid to resources at external locations, down \$102K from June
      - \$0 charged to DALO at external locations, \$117K to RT Deviations
  - Second Contingency payments totaled \$181K, down \$4.4M from the June total of \$4.6M
  - Voltage payments were \$77K, down \$115K from June
  - Distribution payments were zero, unchanged from June
  - NCPC payments over the period as percent of Energy Market value were 1.3%



# Summer 2015 – Mostly Mild Weather

- Limited number of days that temperatures were 90° or higher
  - On these days the Dew Points were mid-to-upper 60°
- June 2015 peak was 20,742 MW on June 23 @17:00
- Limited number of days that the peak exceeded 22,000 MW
  - Monday, July 20 @17:00      24,398 MW (Peak day so far)
  - Tuesday, July 21 @18:00      22,522 MW
  - Tuesday, July 28 @17:00      23,064 MW
  - Wednesday, July 29 @17:00    24,376 MW
  - Thursday, July 30 @15:00      23,708 MW (Storm front came through)
- System peak has shifted to later in the day, with the peak occurring for hour-ending 17:00, and on some days for hour-ending 18:00



# Forward Capacity Market (FCM) Highlights

- CCP #6 (2015-2016)
  - Termination discussions continue with non-commercial resources that are late
- CCP #7 (2016-2017)
  - Second reconfiguration auction will be held August 3-5
    - Entering the CCP, it is estimated that the Transmission Security Analysis margin for NEMA/Boston will be about 373 MW short
- CCP #8 (2017-2018)
  - Second bilateral transaction window will be May 2-6, 2016
  - Second reconfiguration auction will be August 1-3, 2016
- CCP #9 (2018-2019)
  - First bilateral transaction window will be April 1-7, 2016
  - First reconfiguration auction will be June 1-3, 2016

CCP – Capacity Commitment Period



# FCM Highlights, cont.

- CCP #10 (2019-2020)
  - Transfer limits and requirements development discussion continues at the PSPC
    - FERC filing to be made no later than November 10
  - New resource qualification packages are being reviewed by both the IMM and System Planning. Qualification Notification Determinations will be disseminated no later than September 26.
  - Non-price retirement window is open and will close on October 12
    - To date, only one retirement was received for less than 5 MW



# FERC Order 1000

- ISO, PJM, and NYISO made interregional FERC Order 1000 compliance filings on July 13
- ISO, PJM, and NYISO are developing joint interregional planning procedures



# Highlights, cont.

- The lowest 50/50 and 90/10 Summer Operable Capacity Margin is projected for week beginning September 5, 2015.
- The lowest 50/50 and 90/10 Fall Operable Capacity Margin is projected for week beginning September 26, 2015.



# 2014/15 Winter Reliability Program Update (No Change from Prior Month)

- Dual Fuel Commissioning (DFC) Program
  - Participation:
    - 6 Units submitted intent to commission Dual Fuel Capability
      - 4 units for 2014/15 (1,039 MW)
      - 2 units for 2015/16 (735 MW)
    - Total winter seasonal claimed capability added is 1,774 MW
  - DFC Activity and related NCPC:
    - Units commissioned (as of July 31st): 3 successful, 1 outstanding
    - Total NCPC Commissioning Cap: \$5.7M
      - 2014/15: \$3.56M
      - 2015/16: \$2.19M
    - NCPC Incurred (Nov 1-July 31): \$1.0M
    - Remaining Commissioning Cap for 2014/15: \$0.8M

# SYSTEM OPERATIONS



# System Operations

<b><u>Weather Patterns</u></b>	Boston	Temperature –Normal ( -0.2°) Max: 92, Min: 59 Precipitation 2.09” –Below Normal Normal – 3.06”	Hartford	Temperature – Below Normal ( -0.7°) Max: 95, Min: 54 Precipitation 3.07” - Below Normal Normal – 3.67”
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<b><u>Peak Load:</u></b>	24,398 MW	July 20, 2015	17:00 (ending)
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<b><u>MLCC2:</u> 7/20/2015</b>	<b>Capacity Deficiency</b>	<b>Declared – 7/20/15 11:30</b> <b>Cancelled – 7/20/15 22:00</b>
<b><u>OP-4:</u> None</b>		

<b><u>NPCC Simultaneous Activation of Reserve Events:</u></b>		
Date	Area	MW
7/6/2015	NE	607
7/8/2015	NY	1040
7/14/2015	NY	578
7/24/2015	NE	720
7/30/2015	NY	809

# System Operations

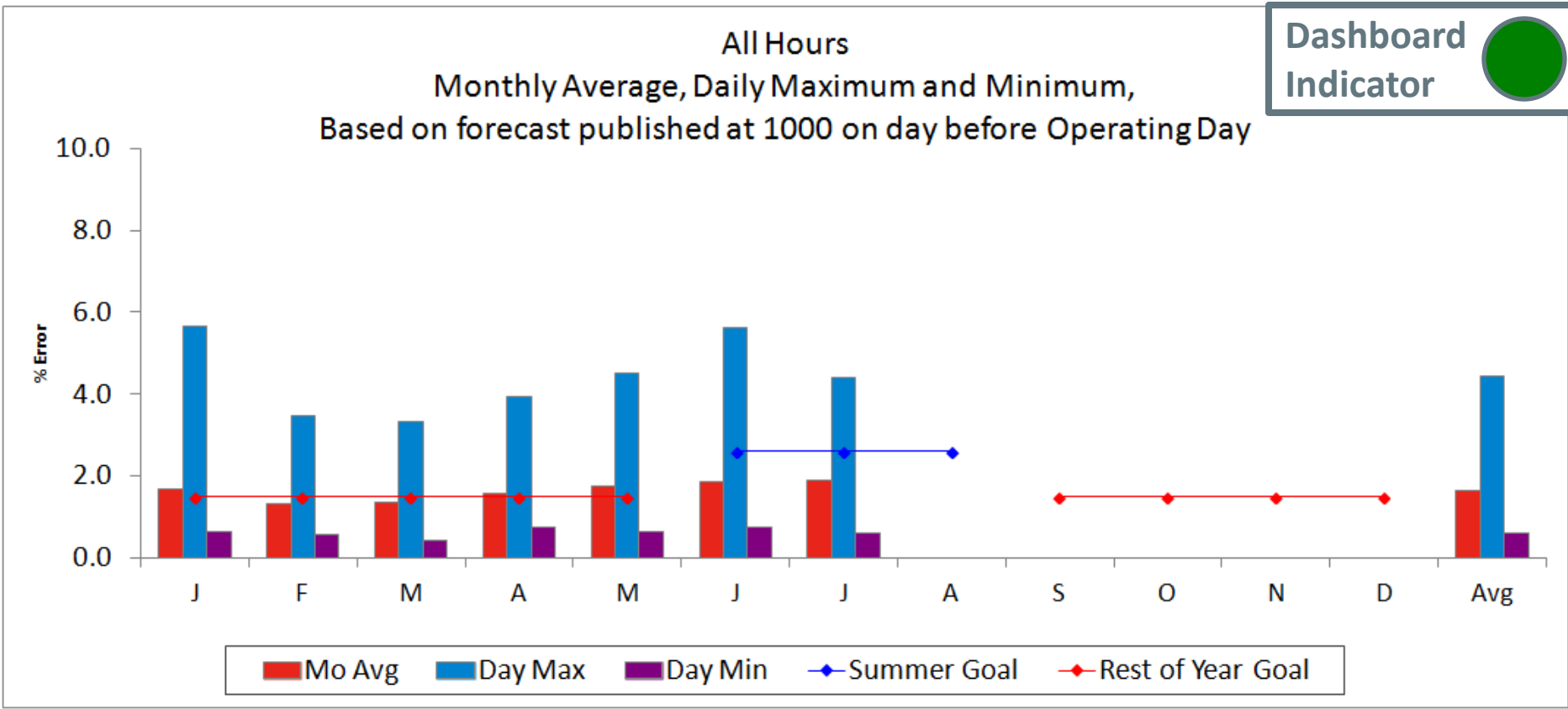
## Minimum Generation Warnings & Events:

Minimum Generation Warning	7/5/15, 00:00 – 09:00	Self Schedules Denied Interchange Cuts
Minimum Generation Event	7/5/15, 06:00 – 08:15	Self Schedules Denied Interchange Cuts



# 2015 System Operations - Load Forecast Accuracy

Dashboard Indicator 

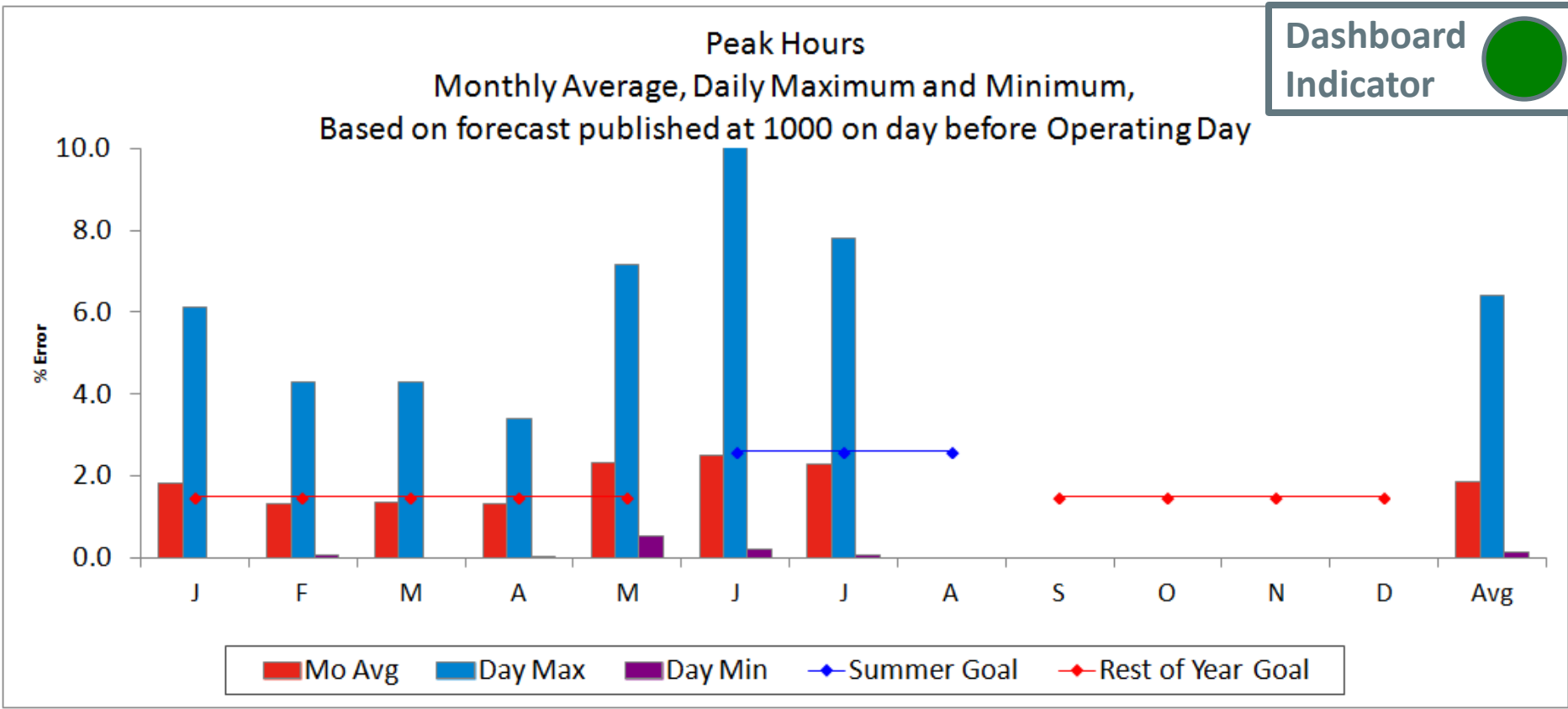


Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.70	1.31	1.37	1.59	1.76	1.88	1.91						1.65
Day Max	5.66	3.47	3.35	3.93	4.53	5.64	4.41						4.44
Day Min	0.65	0.57	0.44	0.74	0.63	0.75	0.60						0.63
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.70	1.31	1.37	1.59	1.76								1.55
Summer Actual						1.88	1.91						1.90

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

# 2015 System Operations - Load Forecast Accuracy cont.

**Dashboard Indicator** 



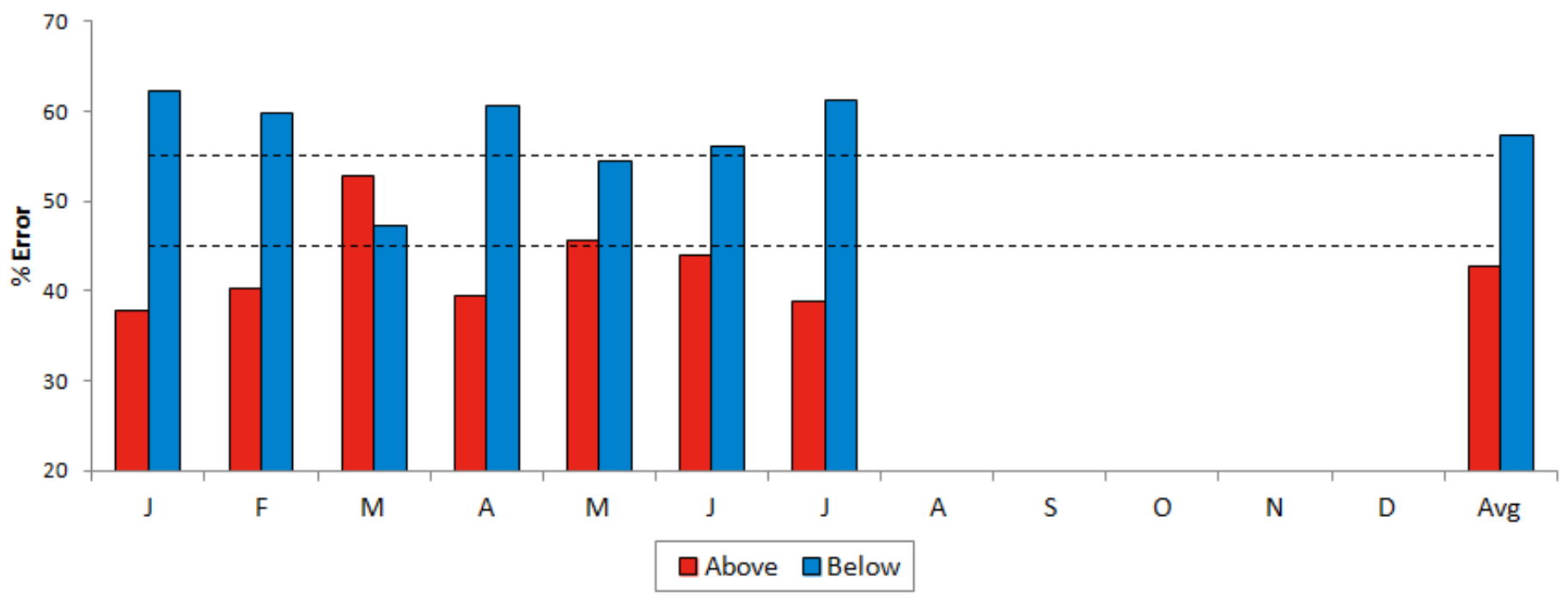
Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.84	1.32	1.36	1.32	2.34	2.52	2.29						1.86
Day Max	6.13	4.31	4.31	3.40	7.15	11.57	7.80						6.40
Day Min	0.00	0.08	0.00	0.03	0.53	0.22	0.06						0.13
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.84	1.32	1.36	1.32	2.34								1.64
Summer Actual						2.52	2.29						2.40

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

# 2015 System Operations - Load Forecast Accuracy cont.

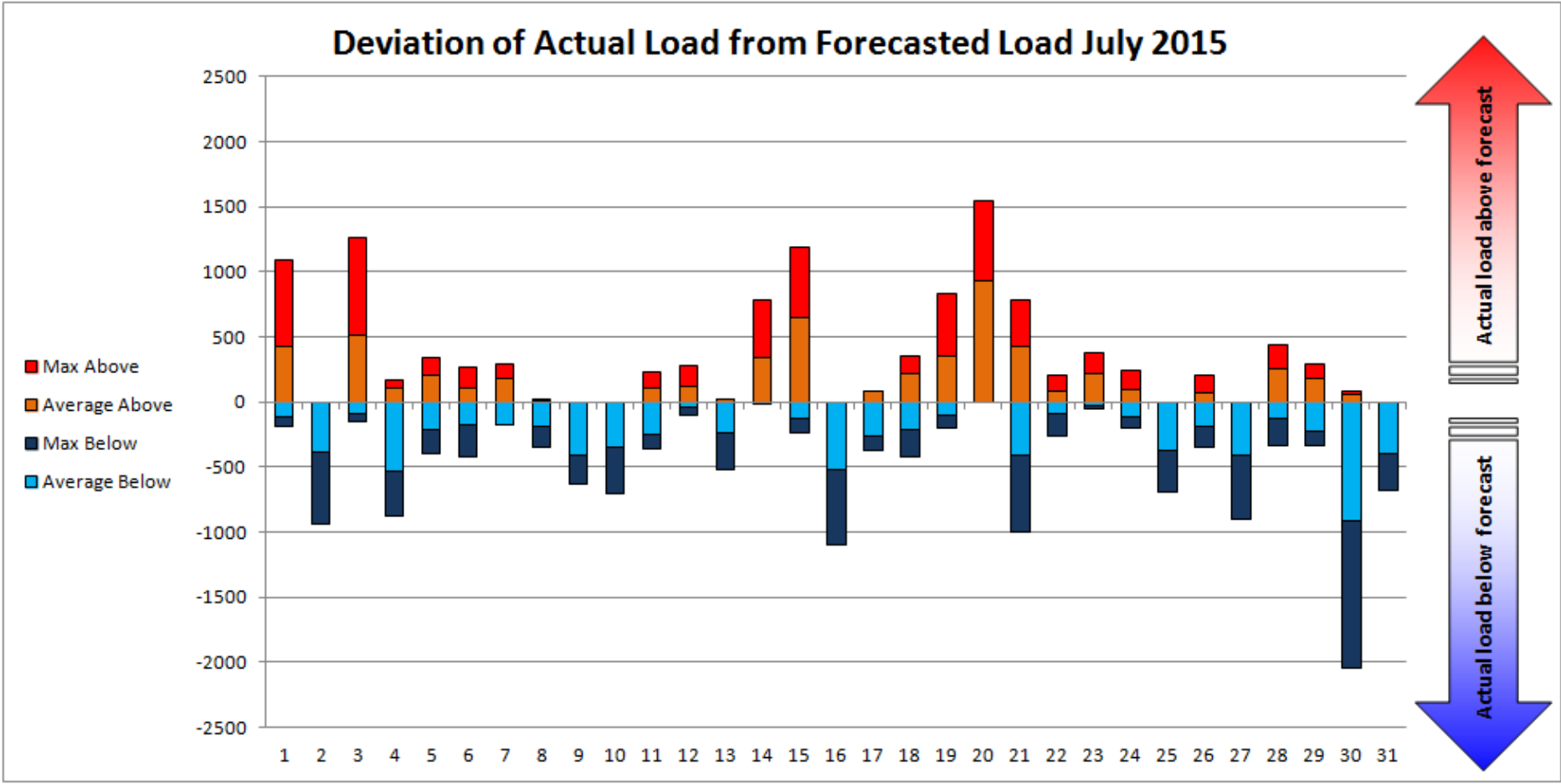
Percent of Hours Actual Load  
 Above vs. Below Forecast  
 Based on LF published by 1000, day before Operating Day

Target = 50%  
 Plus/Minus = 5%



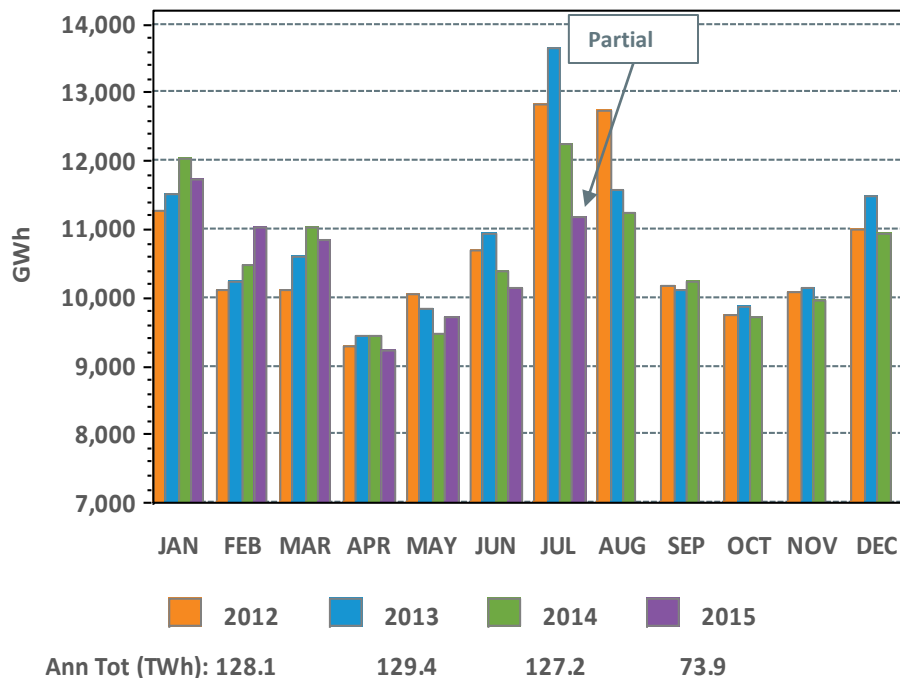
	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	37.8	40.2	52.8	39.4	45.6	43.9	38.8						43
Below %	62.2	59.8	47.2	60.6	54.4	56.1	61.2						57
Avg Above	143.4	147	169.7	130.2	215.1	158.9	185.8						165
Avg Below	-235.8	-208.2	-146.1	-179.5	-157.4	-212.7	-247.6						-198
Avg All	-81	-57	17	-49	34	-55	-70						-37

# 2015 System Operations - Load Forecast Accuracy cont.

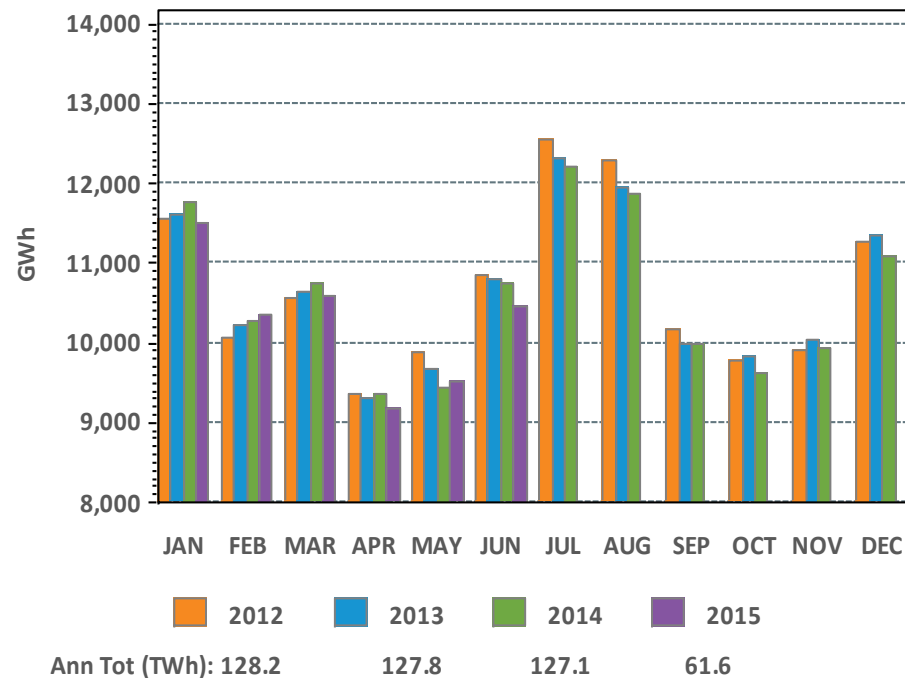


# Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

Net Energy for Load (NEL)



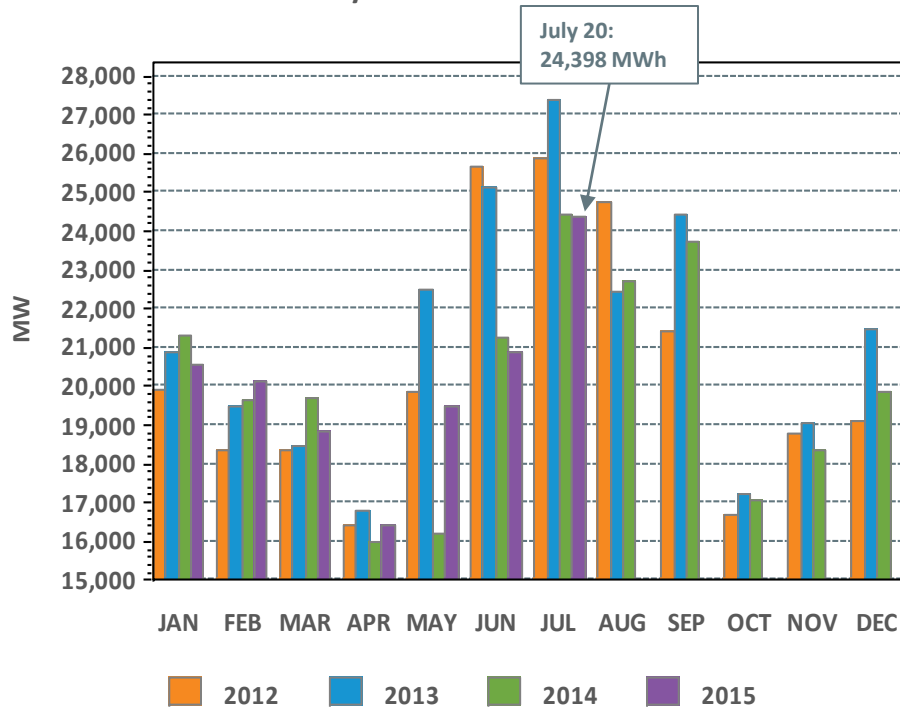
Weather Normalized NEL



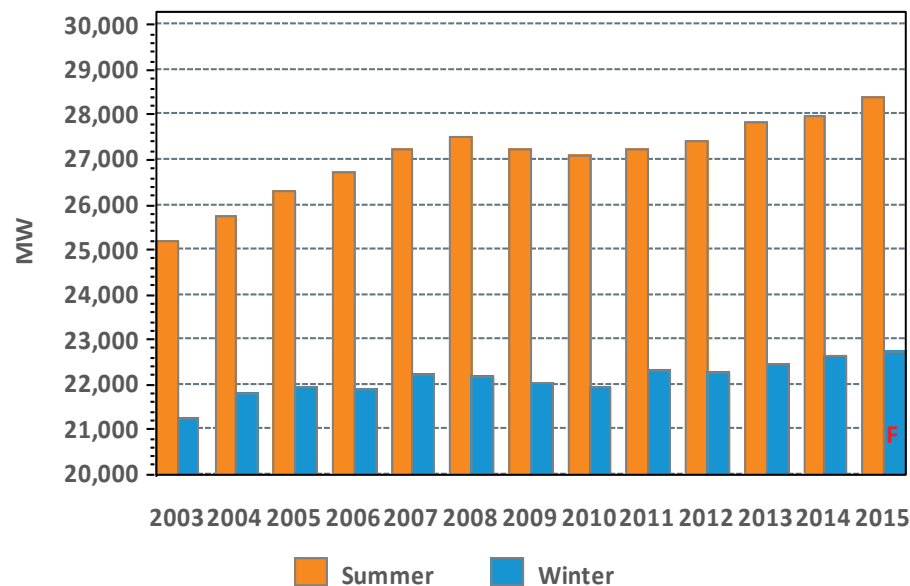
NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load'. NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed.  
 Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

# Monthly Peak Loads and Weather Normalized Seasonal Peak History

System Peak Load



Weather Normalized Seasonal Peaks

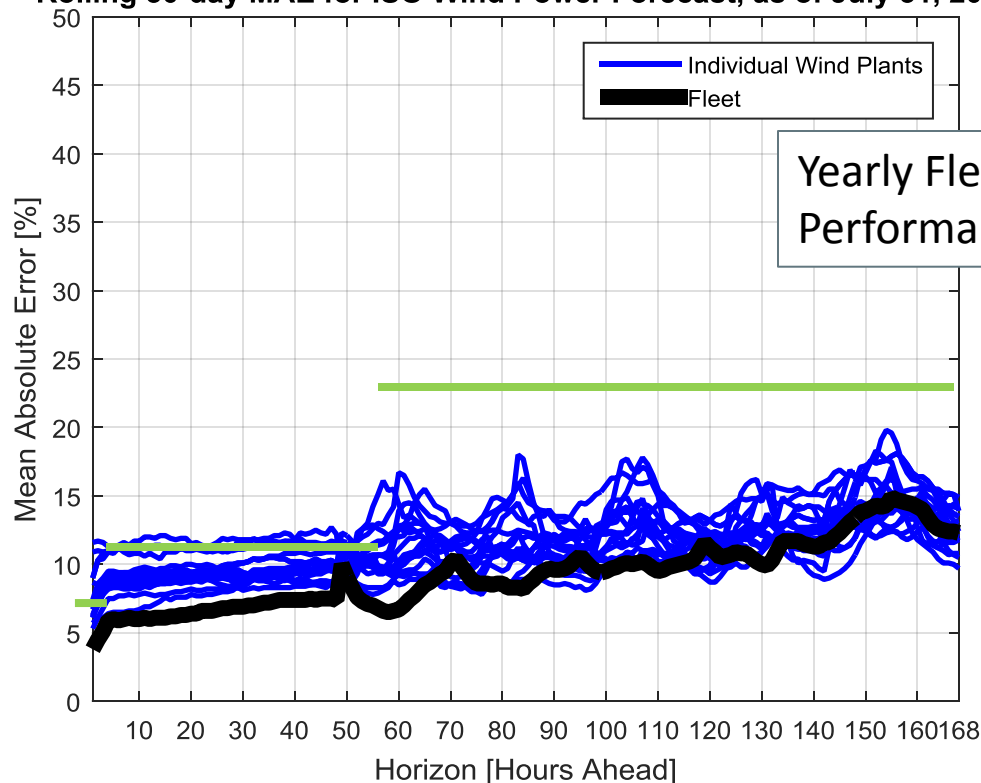


Winter beginning in year displayed

F – designates forecasted values, which are updated in April/May of the following year; represents “gross forecast”

# Wind Power Forecast Error Statistics: MAE

Rolling 30-day MAE for ISO Wind Power Forecast, as of July 31, 2015

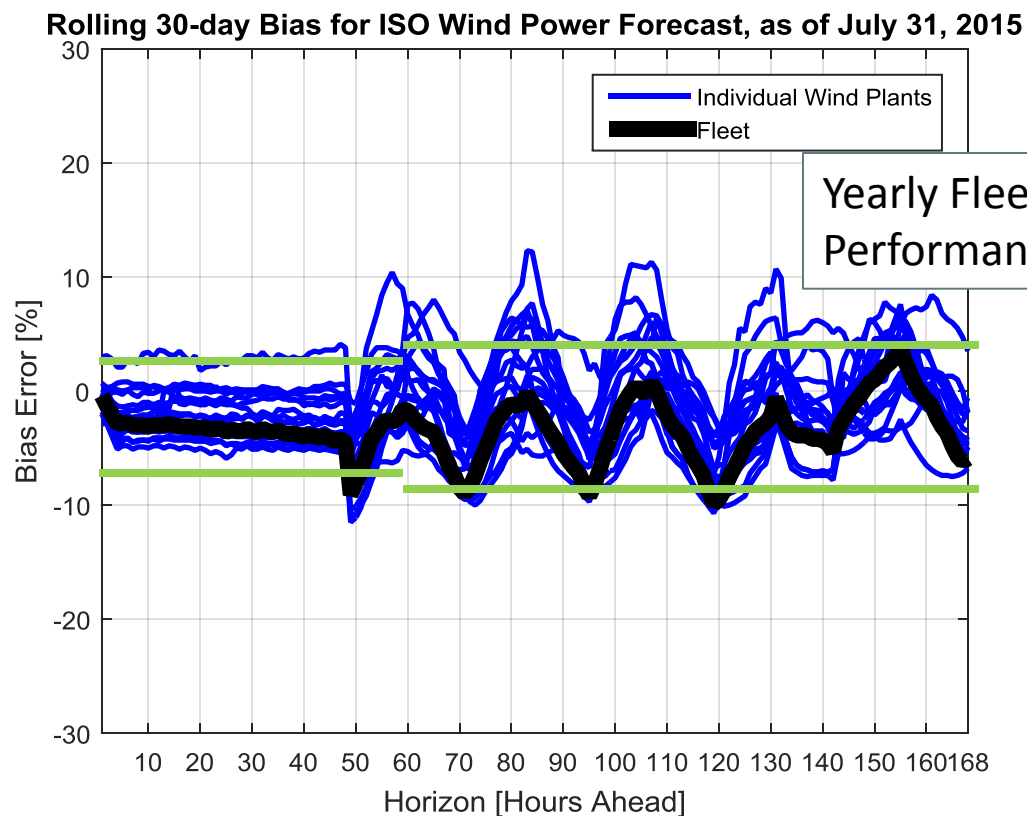


Dashboard Indicator 

Yearly Fleet  
Performance targets 

Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/GH forecast is very good compared to industry standards, and MAE continues to be well within the yearly performance targets specified in the forecast RFP.

# Wind Power Forecast Error Statistics: Bias



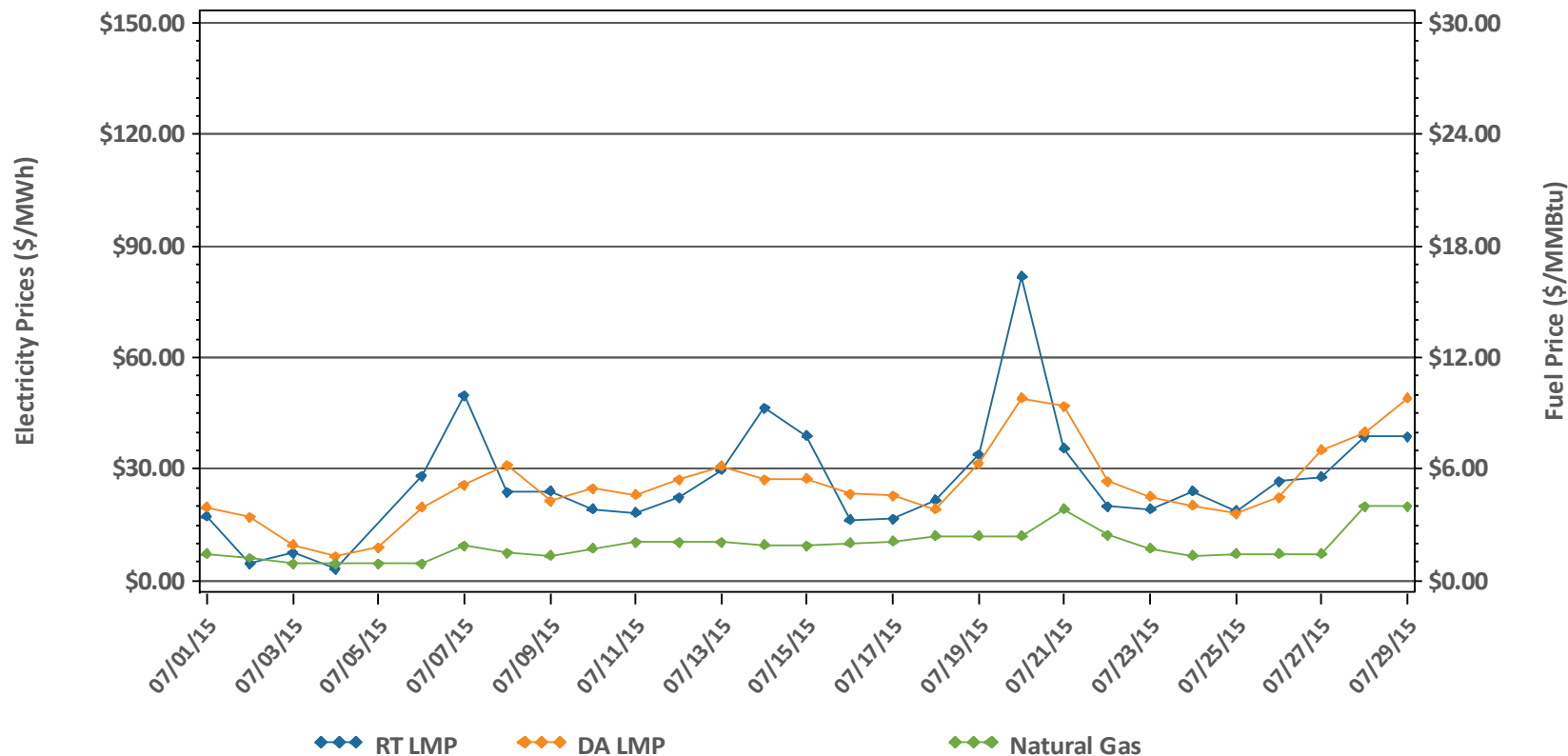
Dashboard Indicator 

Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/GH forecast is very good compared to industry standards, and monthly values for July are mostly within yearly performance targets specified in the forecast RFP.

# MARKET OPERATIONS



# Daily DA and RT ISO-NE Hub Prices and Input Fuel Prices: July 1-29, 2015

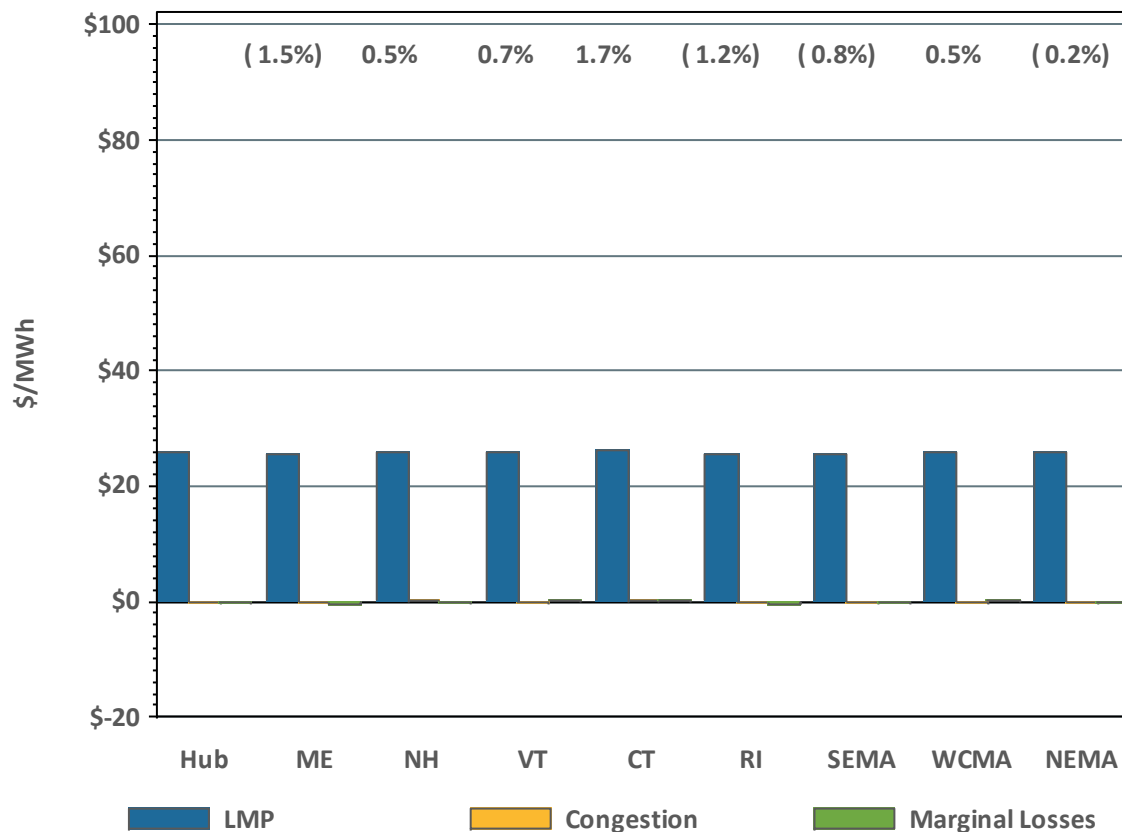


Underlying natural gas data furnished by:



Average price difference over this period (DA-RT): \$0.22  
 Average price difference over this period ABS(DA-RT): \$7.98  
 Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 31%  
 Gas price is average of Massachusetts delivery points

# DA LMPs Average by Zone & Hub, July 2015

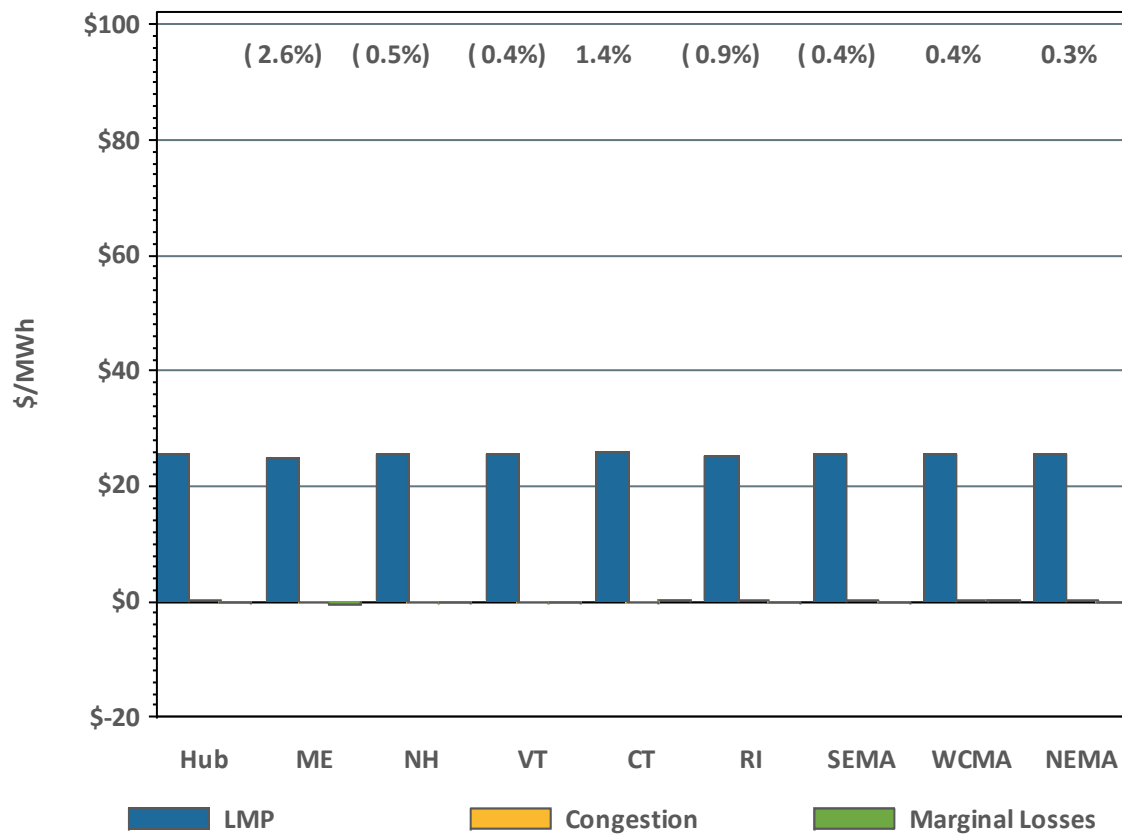


ME - Maine  
 NH - New Hampshire  
 VT - Vermont  
 CT - Connecticut

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



# RT LMPs Average by Zone & Hub, July 2015



# Definitions

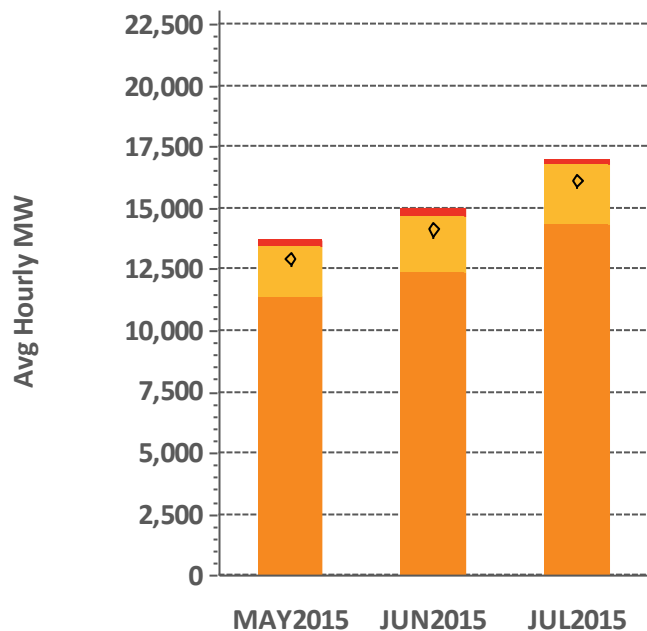
Day-Ahead Concept	Definition
Day-Ahead Load Obligation ( <b>DALO</b> )	The sum of day-ahead cleared load (including pump load), exports, and virtual purchases (excluding bulk losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports



# Components of Cleared DA Supply and Demand

## – Last Three Months

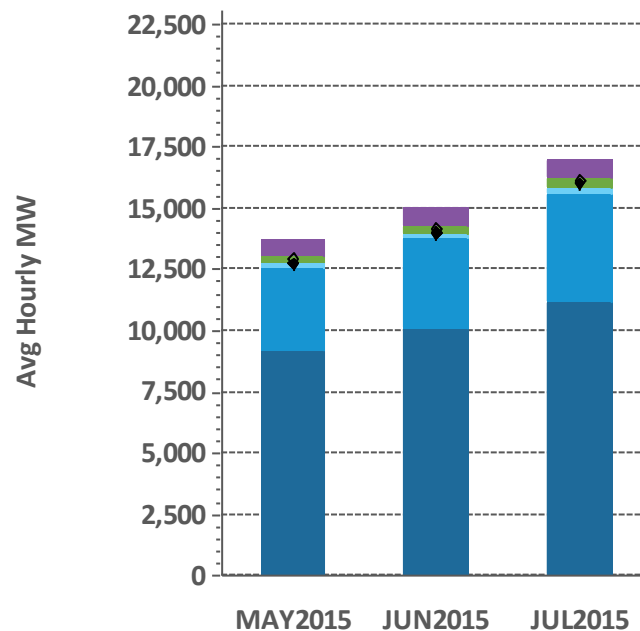
### Supply



■ Gen      ■ Imports  
■ Incs      ◇ DA Fcst Load

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

### Demand



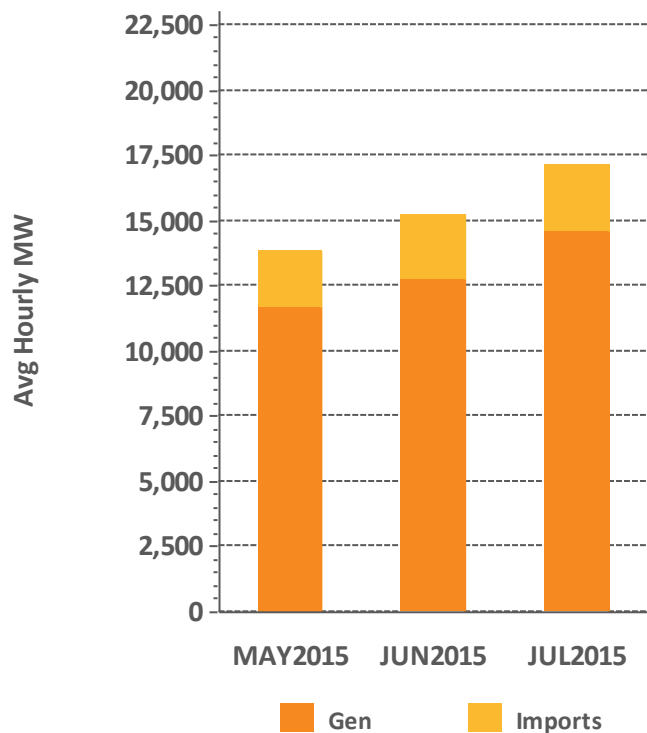
■ Fixed Dem      ■ PrSens Dem      ■ Decs  
■ Losses      ■ Exports      ◇ Act Load

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

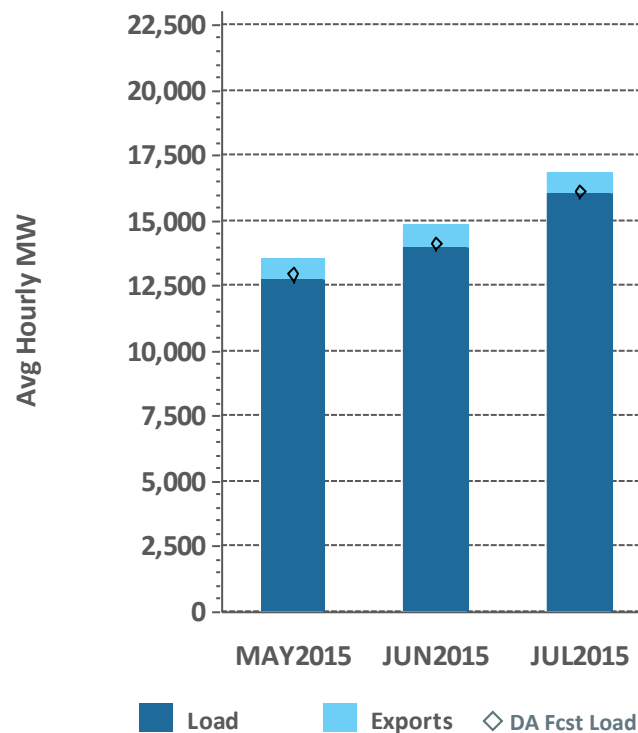


# Components of RT Supply and Demand – Last Three Months

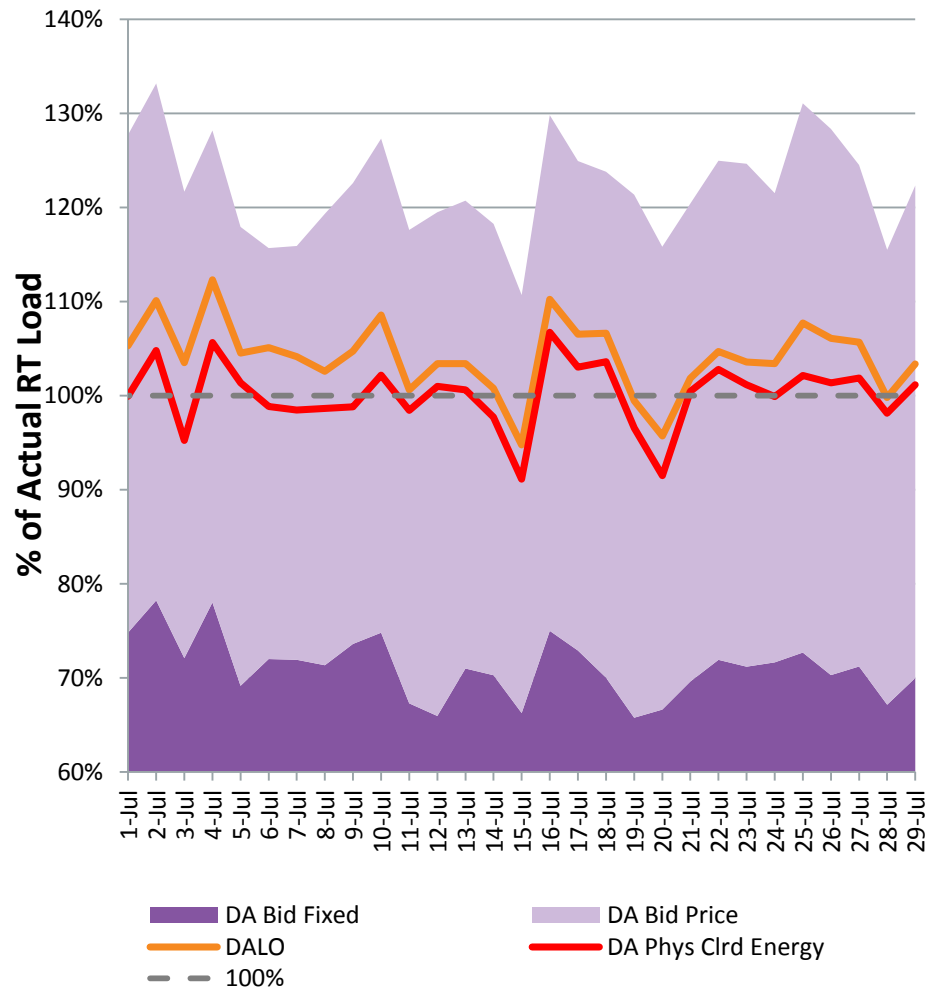
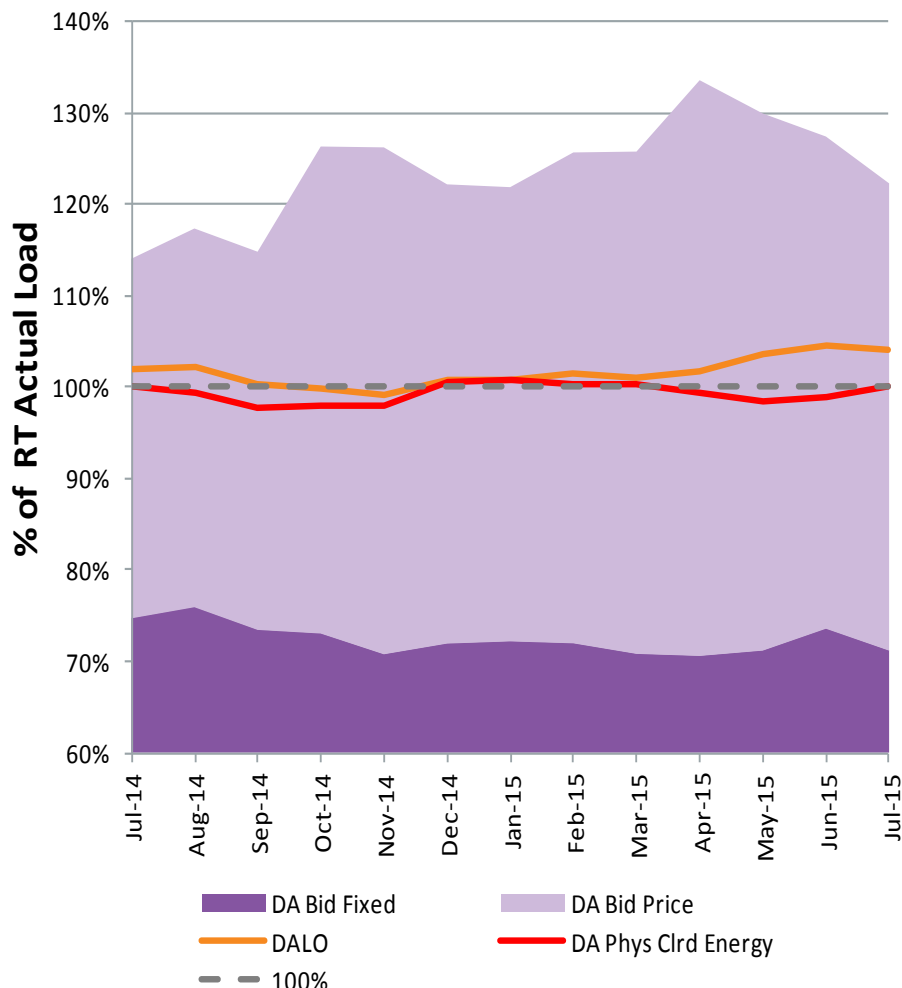
## Supply



## Demand



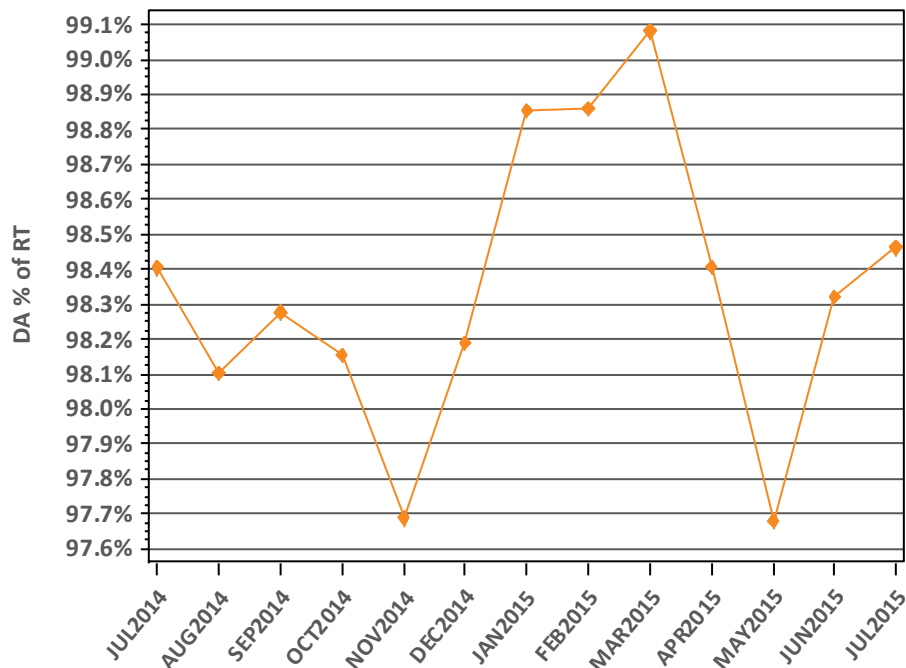
# DAM Volumes vs. RT Actual Load (Peak Hour): Monthly and Daily



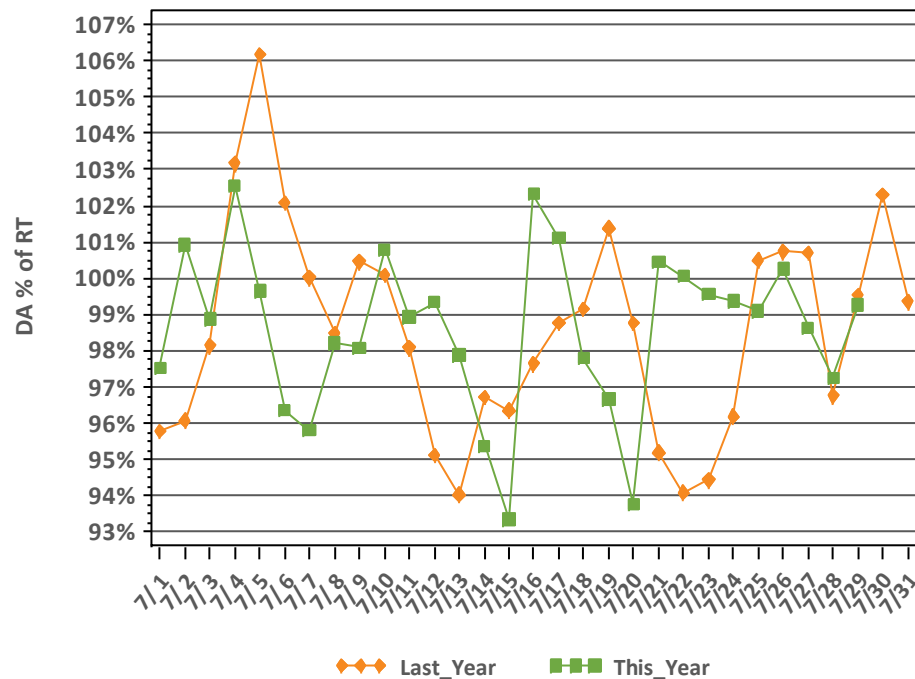
Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load.

# DA vs. RT Load Obligation: July, This Year vs. Last Year

Monthly, Last 13 Months



Daily, This Year vs. Last Year

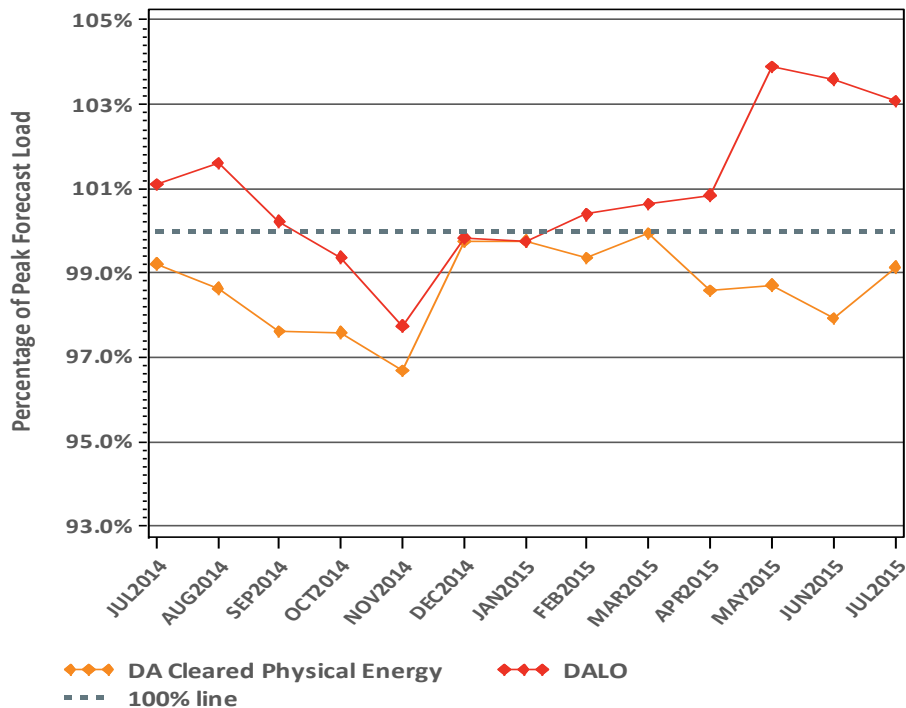


\*Hourly average values

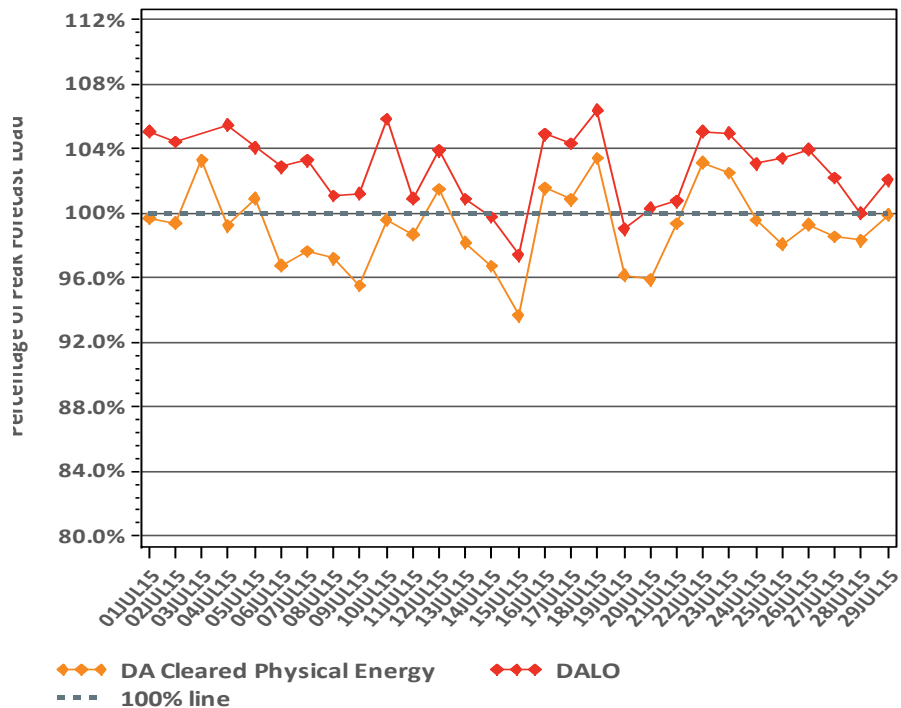


# DA Volumes as % of Forecast (Peak Hour)

Monthly, Last 13 Months

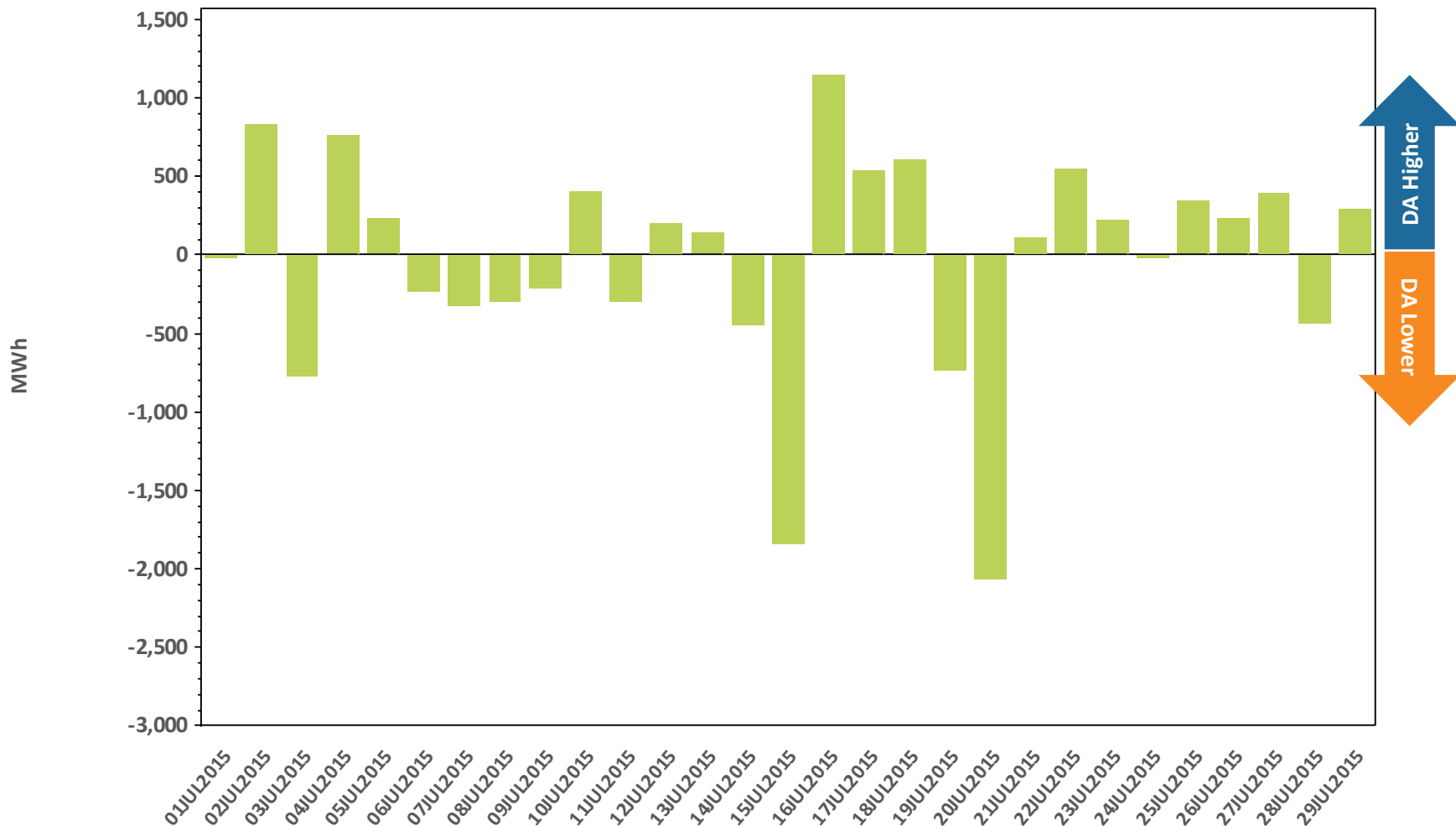


Daily: This Month



\*Forecasted peak hour is reflected.

# DA Cleared Physical Energy Difference from RT System Load at Peak Hour

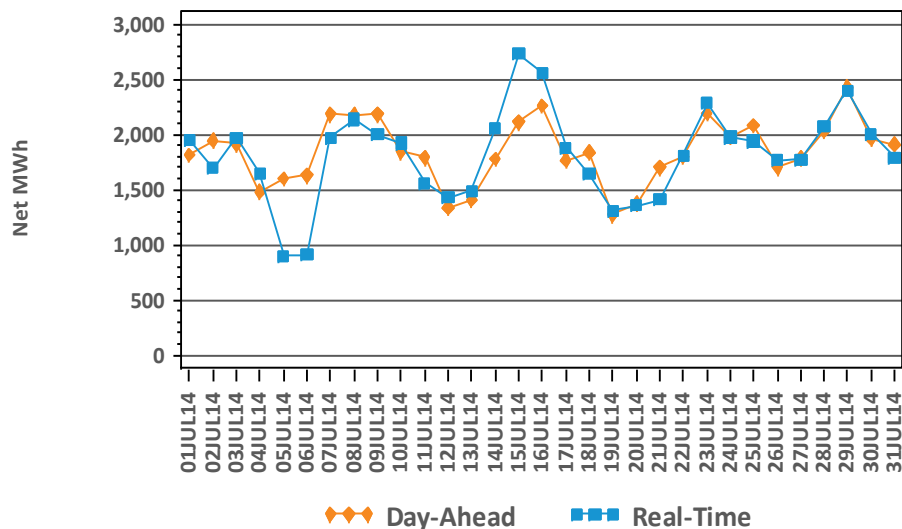


\*Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.

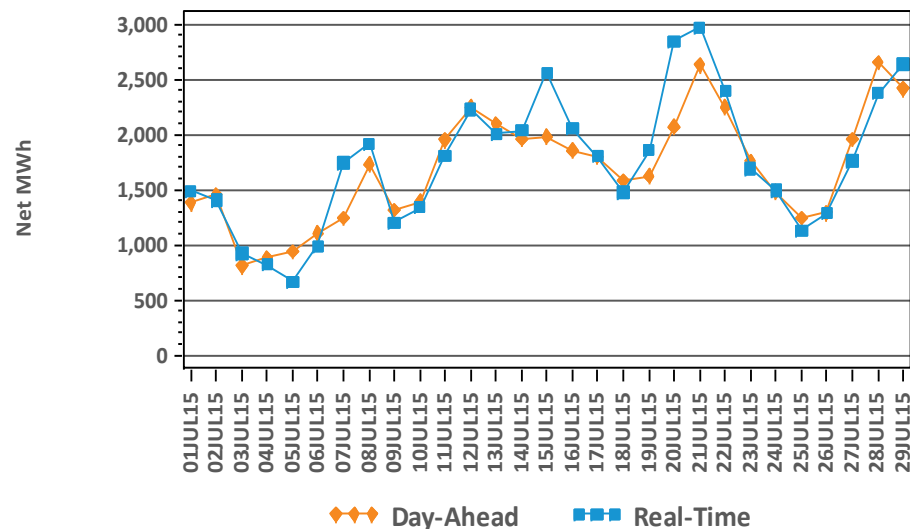
# DA vs. RT Net Interchange

## July 2015 vs. July 2014

Hourly Average by Day, Last Year

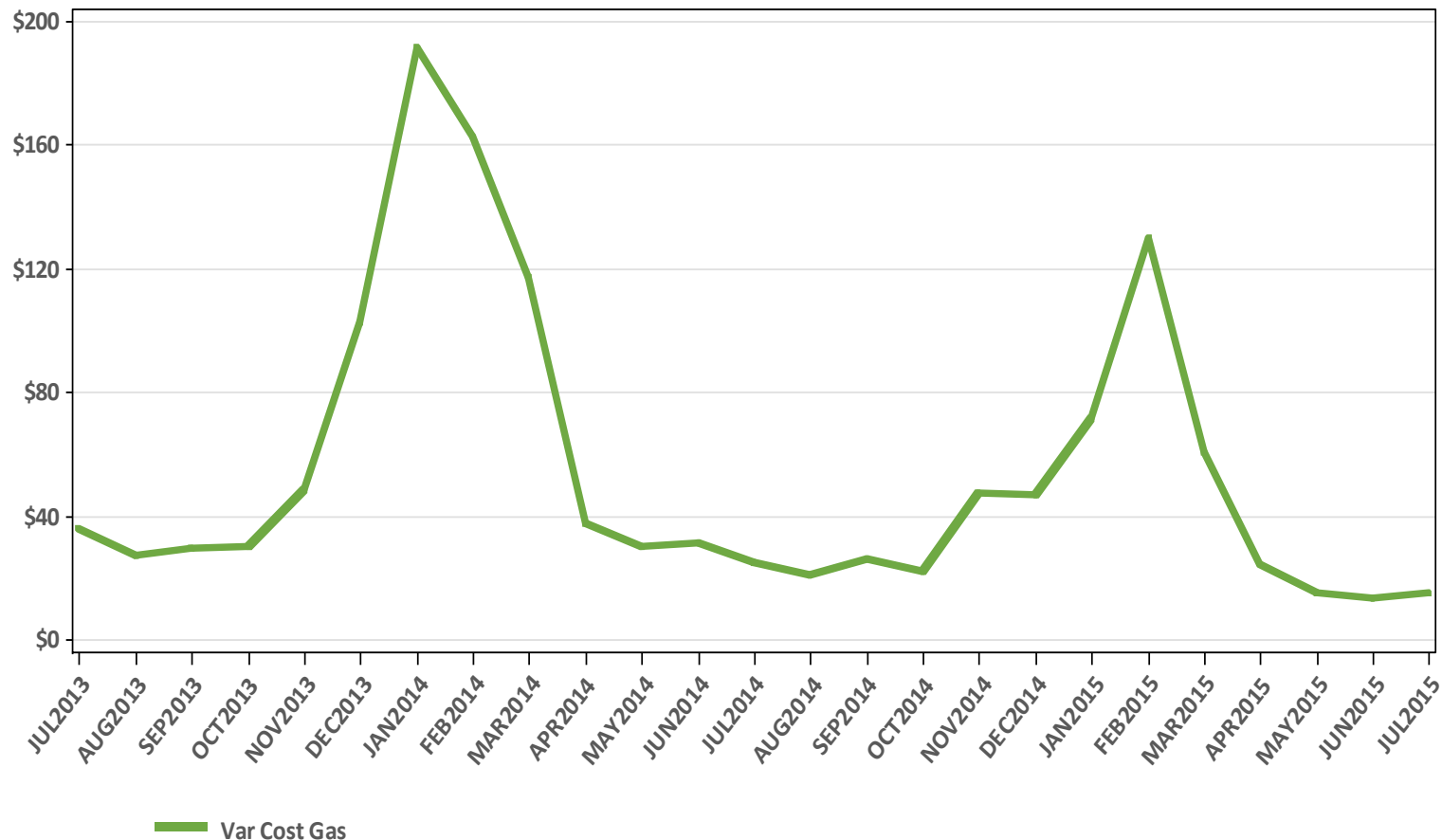


Hourly Average by Day, This Year



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

# Variable Production Cost of Natural Gas: Monthly

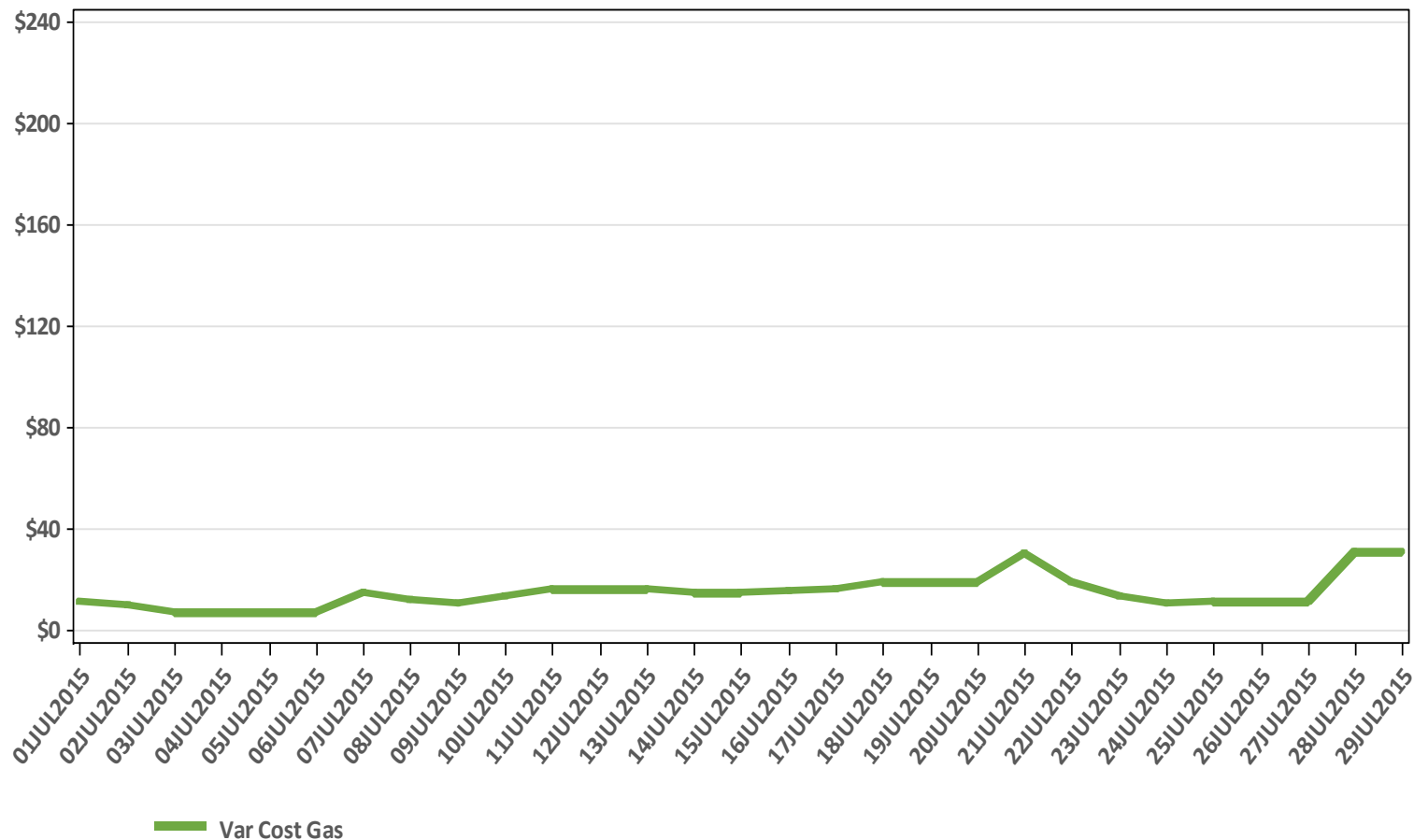


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:



# Variable Production Cost of Natural Gas: Daily



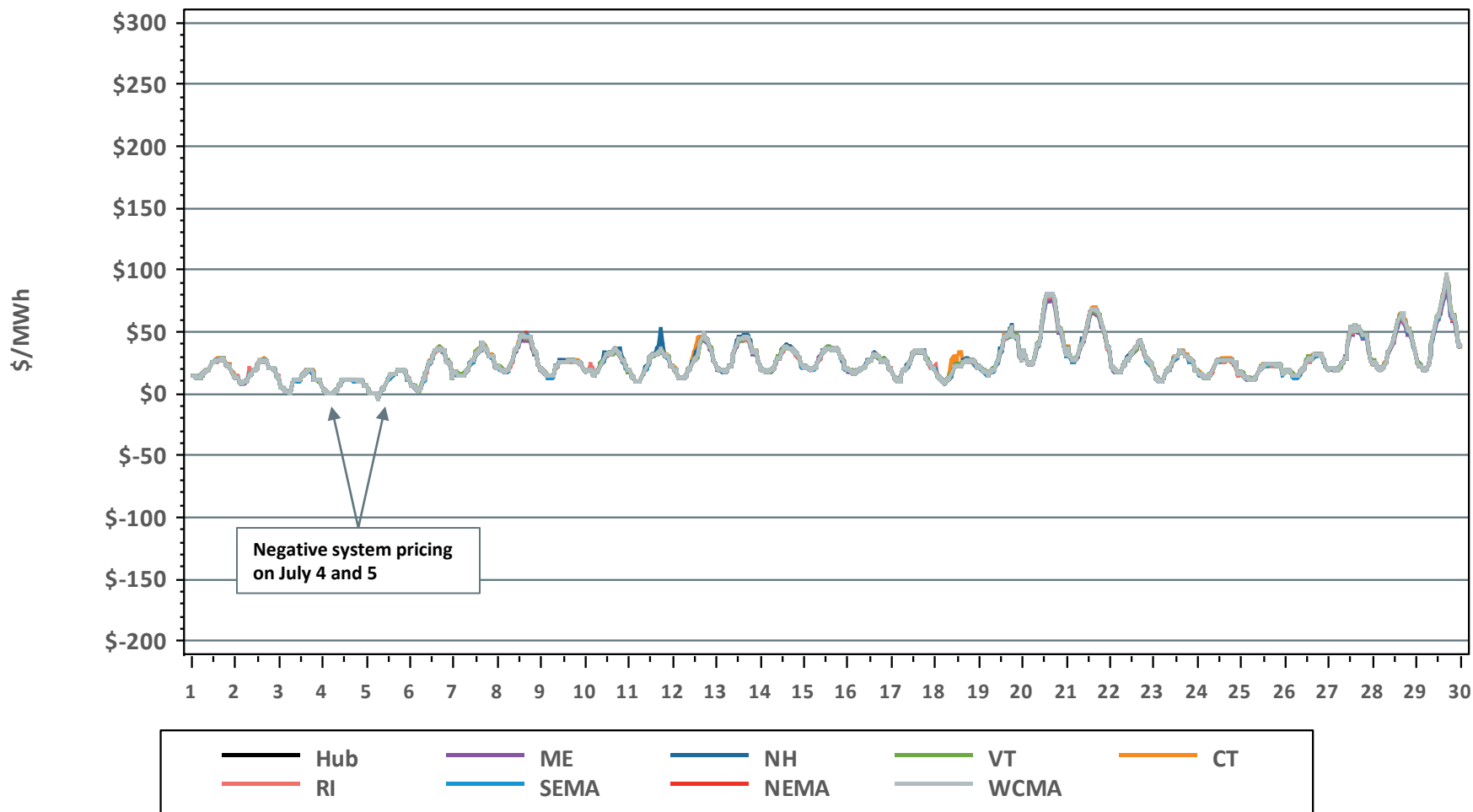
Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:



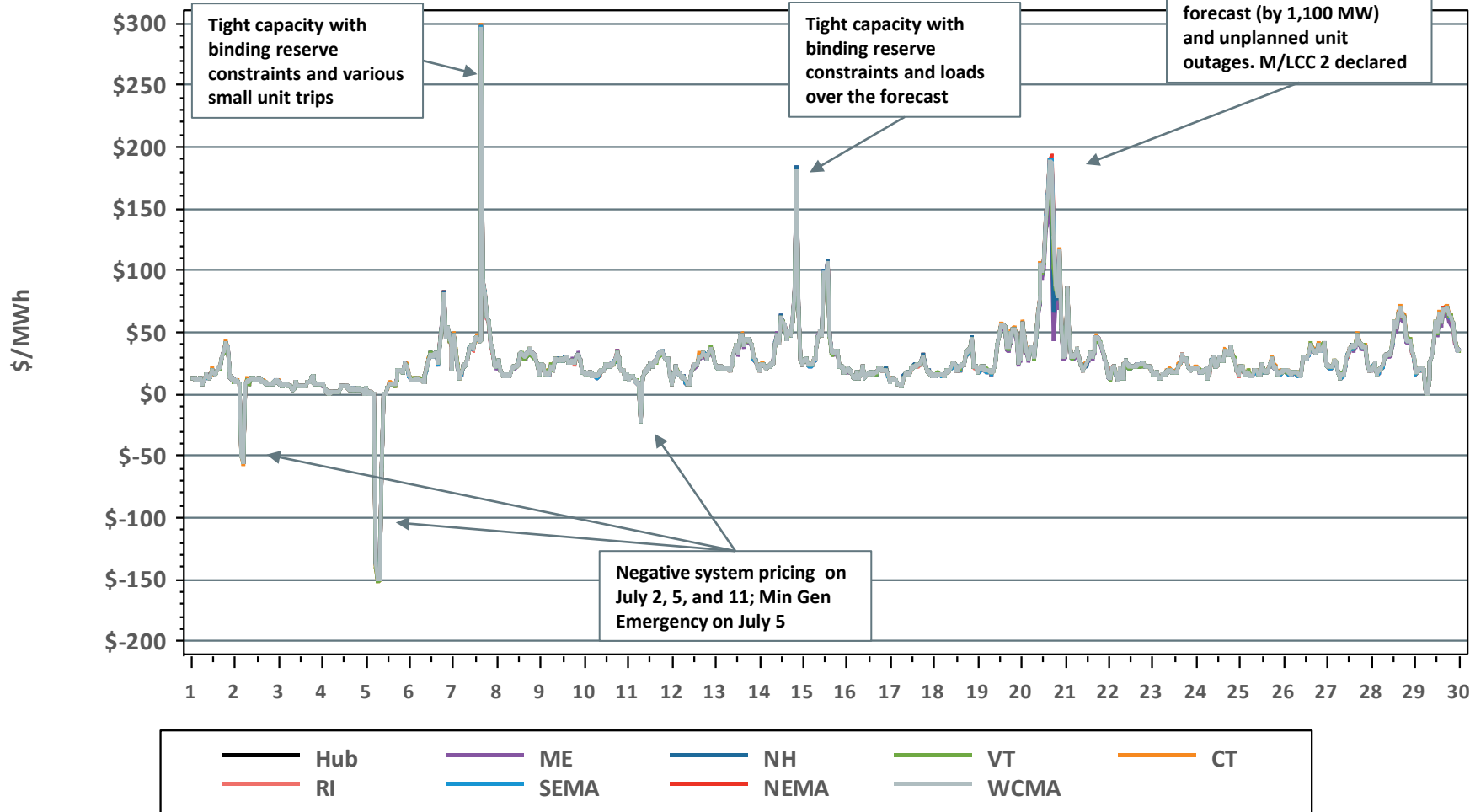
# Hourly DA LMPs, July 1-29, 2015

Hourly Day-Ahead LMPs

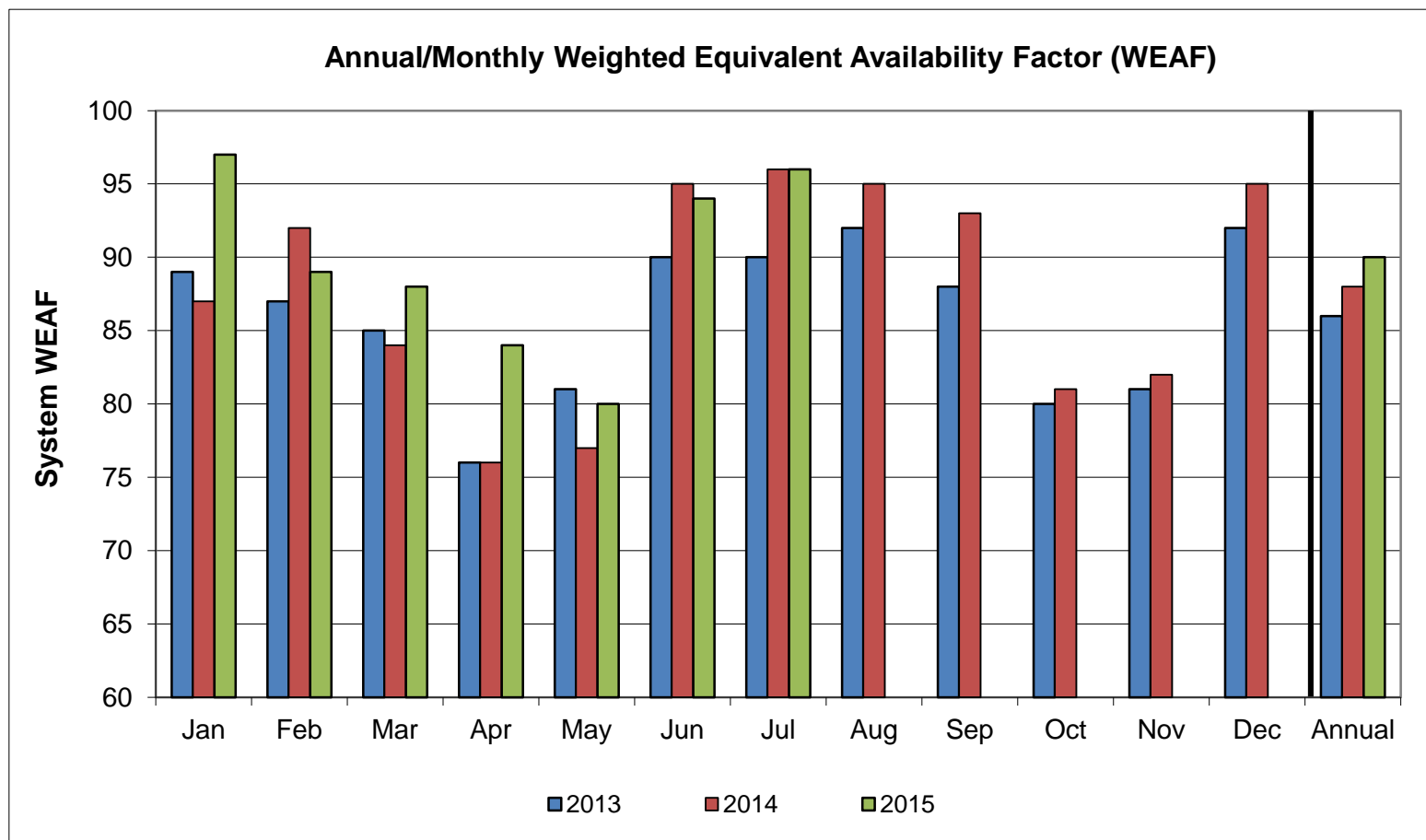


# Hourly RT LMPs, July 1-29, 2015

## Hourly Real-Time LMPs



# System Unit Availability



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
<b>2015</b>	97	89	88	84	79	94	96						90
<b>2014</b>	87	92	84	76	77	95	96	95	93	81	82	95	88
<b>2013</b>	89	87	85	76	81	90	90	92	88	80	81	92	86
<b>2012</b>	93	92	88	75	83	93	95	95	91	76	80	89	88

Data as of 8/3/15

# WINTER 2014/15 PIPELINE UTILIZATION – HIGHEST UTILIZATION DAYS



# Pipeline Utilization: Highest Natural Gas Supply Days

- Based on participant requests, slides 42-47 include the highest pipeline utilization days during the 2014/15 winter
  - These are the days when the scheduled gas flow on the pipelines was at greater than or equal to 85% of pipeline operating capacity
  - All schedules provided are scheduled gas flow. Actual flows may have been different.
  - Available room between the scheduled gas and the operating capacity does not automatically imply that gas was available for importing to New England. Upstream constraints also have an effect on gas availability.



# Pipeline Utilization: Highest Natural Gas Supply Days

*All values shown as MMBTU scheduled*

Pipeline	Location	Oper Capacity	2/5/2015	2/2/2015	2/3/2015	2/20/2015	1/7/2015	1/8/2015
Algonquin	Stony Point	1,583,000	1,522,000	1,494,000	1,517,000	1,419,000	1,343,000	1,404,000
Tennessee	Station 245	1,083,300	1,055,954	1,031,956	1,052,473	1,063,907	1,057,514	1,049,334
Iroquois	Waddington*	1,150,000	1,159,707	1,057,020	1,149,931	1,143,748	1,004,092	1,098,291
M&N	Baileyville + Canaport	850,000	736,059	845,683	713,731	833,113	798,047	739,141
PNGTS	E. Hereford (Pittsburg)	168,000	259,335	238,141	259,334	258,472	217,377	259,112
<b>Total</b>		<b>4,834,300</b>	<b>4,733,055</b>	<b>4,666,800</b>	<b>4,692,469</b>	<b>4,718,240</b>	<b>4,420,030</b>	<b>4,549,878</b>
AGT/TGP	Distrigas	457,180	252,676	94,239	132,333	220,704	306,422	254,131
Algonquin	Northeast Gateway	400,000	141,187	322,871	149,320	0	199,819	118,690
<b>Total</b>		<b>5,691,480</b>	<b>393,863</b>	<b>417,110</b>	<b>281,653</b>	<b>220,704</b>	<b>506,241</b>	<b>372,821</b>
			<b>5,126,918</b>	<b>5,083,910</b>	<b>4,974,122</b>	<b>4,938,944</b>	<b>4,926,271</b>	<b>4,922,699</b>

*\* Not all gas is consumed in ISO-NE's footprint, especially Capacity at Iroquois*

# Pipeline Utilization: Highest Natural Gas Supply Days, cont.

*All values shown as MMBTU scheduled*

Pipeline	Location	Oper Capacity	2/19/2015	2/6/2015	1/28/2015	1/9/2015	1/6/2015	2/13/2015
Algonquin	Stony Point	<b>1,583,000</b>	1,337,000	1,486,000	1,518,000	1,509,000	1,421,000	1,521,000
Tennessee	Station 245	<b>1,083,300</b>	1,059,797	1,024,318	1,054,023	1,057,084	1,066,896	1,059,446
Iroquois	Waddington*	<b>1,150,000</b>	1,158,615	1,239,817	1,164,471	1,122,448	1,165,483	1,094,657
M&N	Baileyville + Canaport	<b>850,000</b>	839,543	515,402	660,090	547,666	560,692	656,443
PNGTS	E. Hereford (Pittsburg)	<b>168,000</b>	258,398	259,206	259,322	228,270	233,923	258,351
<b>Total</b>		<b>4,834,300</b>	<b>4,653,353</b>	<b>4,524,743</b>	<b>4,655,906</b>	<b>4,464,468</b>	<b>4,447,994</b>	<b>4,589,897</b>
AGT/TGP	Distrigas	<b>457,180</b>	220,313	163,907	196,791	233,386	164,188	95,763
Algonquin	Northeast Gateway	<b>400,000</b>	0	166,343	0	97,426	181,647	102,579
<b>Total</b>		<b>5,691,480</b>	<b>220,313</b>	<b>330,250</b>	<b>196,791</b>	<b>330,812</b>	<b>345,835</b>	<b>198,342</b>
			<b>4,873,666</b>	<b>4,854,993</b>	<b>4,852,697</b>	<b>4,795,280</b>	<b>4,793,829</b>	<b>4,788,239</b>

*\* Not all gas is consumed in ISO-NE's footprint, especially Capacity at Iroquois*

# Pipeline Utilization: Highest Natural Gas Supply Days, cont.

*All values shown as MMBTU scheduled*

Pipeline	Location	Oper Capacity	1/13/2015	1/10/2015	1/27/2015	2/16/2015	2/17/2015	1/31/2015
Algonquin	Stony Point	<b>1,583,000</b>	1,523,000	1,505,000	1,527,000	1,489,000	1,481,000	1,498,000
Tennessee	Station 245	<b>1,083,300</b>	1,051,746	1,033,266	1,040,717	1,054,193	1,051,017	1,047,184
Iroquois	Waddington*	<b>1,150,000</b>	1,006,324	1,128,637	1,163,714	1,107,362	1,150,123	1,144,754
M&N	Baileyville + Canaport	<b>850,000</b>	610,004	424,199	489,990	576,858	553,041	531,292
PNGTS	E. Hereford (Pittsburg)	<b>168,000</b>	212,148	251,973	259,029	258,419	258,420	259,289
<b>Total</b>		<b>4,834,300</b>	<b>4,403,222</b>	<b>4,343,075</b>	<b>4,480,450</b>	<b>4,485,832</b>	<b>4,493,601</b>	<b>4,480,519</b>
AGT/TGP	Distrigas	<b>457,180</b>	238,813	244,032	215,622	110,488	87,233	150,163
Algonquin	Northeast Gateway	<b>400,000</b>	81,116	134,565	0	78,727	68,712	10,101
<b>Total</b>		<b>5,691,480</b>	<b>319,929</b>	<b>378,597</b>	<b>215,622</b>	<b>189,215</b>	<b>155,945</b>	<b>160,264</b>
			<b>4,723,151</b>	<b>4,721,672</b>	<b>4,696,072</b>	<b>4,675,047</b>	<b>4,649,546</b>	<b>4,640,783</b>

*\* Not all gas is consumed in ISO-NE's footprint, especially Capacity at Iroquois*

# Pipeline Utilization: Highest Natural Gas Supply Days, cont.

*All values shown as MMBTU scheduled*

Pipeline	Location	Oper Capacity	2/15/2015	1/14/2015	2/23/2015	2/9/2015	2/4/2015	1/26/2015
Algonquin	Stony Point	<b>1,583,000</b>	1,461,000	1,521,000	1,484,000	1,532,000	1,466,000	1,510,000
Tennessee	Station 245	<b>1,083,300</b>	1,066,547	1,048,959	1,057,586	1,049,502	1,056,786	1,045,180
Iroquois	Waddington*	<b>1,150,000</b>	1,080,746	1,008,551	1,081,555	1,112,621	1,102,345	1,076,241
M&N	Baileyville + Canaport E. Hereford	<b>850,000</b>	572,808	474,554	410,314	378,148	352,782	502,833
PNGTS	(Pittsburg)	<b>168,000</b>	240,713	256,395	262,042	259,247	257,178	252,546
<b>Total</b>		<b>4,834,300</b>	<b>4,421,814</b>	<b>4,309,459</b>	<b>4,295,497</b>	<b>4,331,518</b>	<b>4,235,091</b>	<b>4,386,800</b>
AGT/TGP	Distrigas	<b>457,180</b>	134,436	285,761	298,005	236,534	206,502	114,702
Algonquin	Northeast Gateway	<b>400,000</b>	69,882	25,200	0	1,008	120,885	31,505
<b>Total</b>		<b>5,691,480</b>	<b>204,318</b>	<b>310,961</b>	<b>298,005</b>	<b>237,542</b>	<b>327,387</b>	<b>146,207</b>
			<b>4,626,132</b>	<b>4,620,420</b>	<b>4,593,502</b>	<b>4,569,060</b>	<b>4,562,478</b>	<b>4,533,007</b>

*\* Not all gas is consumed in ISO-NE's footprint, especially Capacity at Iroquois*

# Pipeline Utilization: Highest Natural Gas Supply Days, cont.

*All values shown as MMBTU scheduled*

Pipeline	Location	Oper Capacity	2/1/2015	1/16/2015	2/10/2015	2/11/2015	1/15/2015	2/12/2015
Algonquin	Stony Point	<b>1,583,000</b>	1,415,000	1,490,000	1,482,000	1,472,000	1,484,000	1,485,000
Tennessee	Station 245	<b>1,083,300</b>	985,756	1,027,843	1,019,829	1,012,186	1,027,672	1,063,400
Iroquois	Waddington*	<b>1,150,000</b>	1,033,464	1,029,171	1,184,989	1,213,423	1,104,356	1,078,457
M&N	Baileyville + Canaport	<b>850,000</b>	544,715	357,004	344,781	340,600	313,293	442,540
PNGTS	E. Hereford (Pittsburg)	<b>168,000</b>	244,564	259,566	259,328	259,230	259,333	256,622
<b>Total</b>		<b>4,834,300</b>	<b>4,223,499</b>	<b>4,163,584</b>	<b>4,290,927</b>	<b>4,297,439</b>	<b>4,188,654</b>	<b>4,326,019</b>
AGT/TGP	Distrigas	<b>457,180</b>	77,445	280,743	184,655	169,030	282,903	100,918
Algonquin	Northeast Gateway	<b>400,000</b>	231,718	87,587	35,253	42,195	0	37,515
<b>Total</b>		<b>5,691,480</b>	<b>309,163</b>	<b>368,330</b>	<b>219,908</b>	<b>211,225</b>	<b>282,903</b>	<b>138,433</b>
			<b>4,532,662</b>	<b>4,531,914</b>	<b>4,510,835</b>	<b>4,508,664</b>	<b>4,471,557</b>	<b>4,464,452</b>

*\* Not all gas is consumed in ISO-NE's footprint, especially Capacity at Iroquois*



# Pipeline Utilization: Highest Natural Gas Supply Days, cont.

*All values shown as MMBTU scheduled*

Pipeline	Location	Oper Capacity	1/30/2015
Algonquin	Stony Point	<b>1,583,000</b>	1,482,000
Tennessee	Station 245	<b>1,083,300</b>	1,030,575
Iroquois	Waddington*	<b>1,150,000</b>	1,133,133
M&N	Baileyville + Canaport	<b>850,000</b>	454,716
PNGTS	E. Hereford (Pittsburg)	<b>168,000</b>	259,328
<b>Total</b>		<b>4,834,300</b>	<b>4,359,752</b>
AGT/TGP	Distrigas	<b>457,180</b>	81,734
Algonquin	Northeast Gateway	<b>400,000</b>	18,510
<b>Total</b>		<b>5,691,480</b>	<b>100,244</b>
			<b>4,459,996</b>

*\* Not all gas is consumed in ISO-NE's footprint, especially Capacity at Iroquois*



# BACK-UP DETAIL



# LOAD RESPONSE



# Capacity Supply Obligation (CSO) MW by Demand Resource Type for August 2015

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	117.0	5.1	126.5	0.0	248.6
NH	8.0	15.1	75.3	0.0	98.3
VT	29.2	3.7	99.2	0.0	132.1
CT	103.1	109.2	74.4	310.7	597.4
RI	14.0	13.0	158.6	0.0	185.6
SEMA	10.7	10.8	206.7	0.0	228.3
WCMA	30.4	20.5	206.8	44.2	302.0
NEMA	34.1	7.5	375.0	0.0	416.6
<b>Total</b>	<b>346.5</b>	<b>184.9</b>	<b>1,322.5</b>	<b>354.9</b>	<b>2,208.8</b>

\* Real Time Demand Response

\*\* Real Time Emergency Generation

NOTE: CSO values include T&D loss factor (8%) and, as applicable, a reserve margin gross-up of either 14.3% or 16.1%, respectively, for portions of resources that selected a multi-year obligation in the FCA 1 or FCA 2. Otherwise, reserve margin gross-ups were discontinued with FCA 3.

# NEW GENERATION



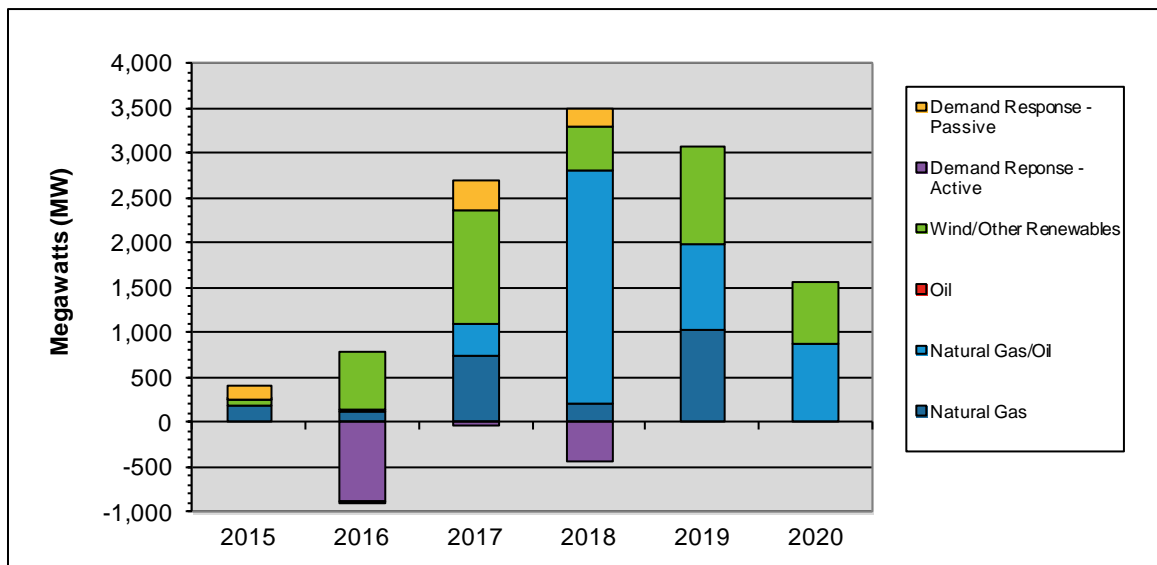
# New Generation Update

## *Based on Queue as of 7/31/15*

- Five new projects, with a total rating of 82 MW, have applied for interconnection study since the last update
  - The projects consist of four new photovoltaic plants and one new landfill gas facility that are all expected to be in service in 2016
  - Two projects went commercial and two withdrew from the Queue, resulting in a net decrease in new generation projects of 908 MW
- In total, 80 generation projects are currently being tracked by the ISO, totaling approximately 11,300 MW



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



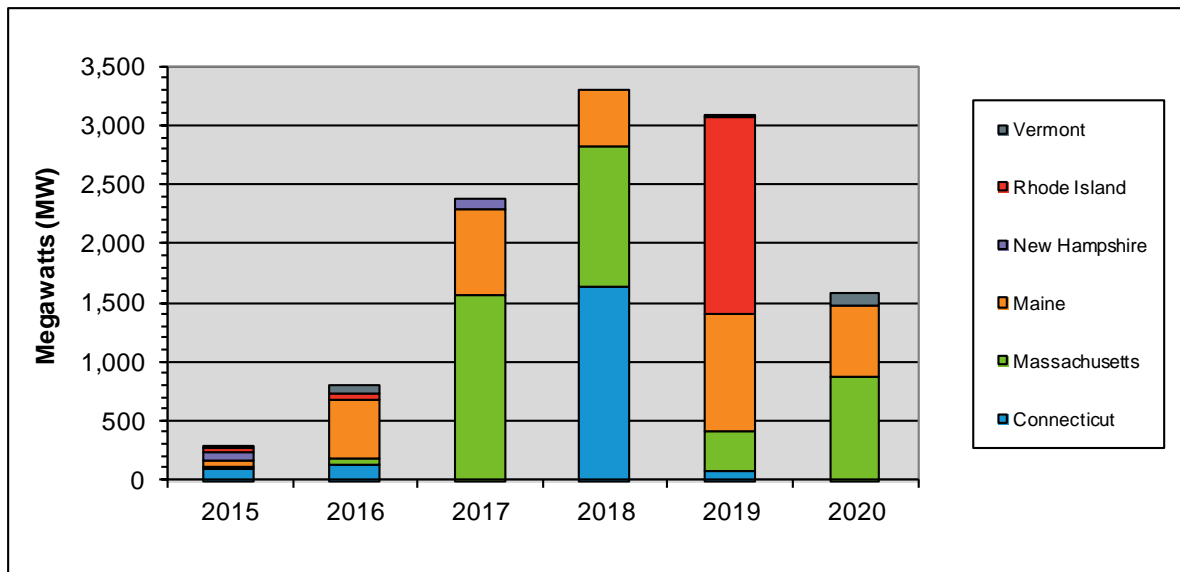
	2015	2016	2017	2018	2019	2020	Total MW	% of Total <sup>1</sup>
<b>Demand Response - Passive</b>	157	-12	330	196	0	0	670	6.3
<b>Demand Response - Active</b>	3	-868	-37	-433	0	0	-1,335	-12.5
<b>Wind &amp; Other Renewables</b>	77	658	1,274	495	1,092	698	4,294	40.1
<b>Oil</b>	0	0	0	0	0	0	0	0.0
<b>Natural Gas/Oil<sup>2</sup></b>	0	10	346	2,599	965	870	4,790	44.7
<b>Natural Gas</b>	180	123	745	210	1,030	0	2,288	21.4
<b>Totals</b>	<b>417</b>	<b>-89</b>	<b>2,658</b>	<b>3,067</b>	<b>3,087</b>	<b>1,568</b>	<b>10,707</b>	<b>100.0</b>

<sup>1</sup> Sum may not equal 100% due to rounding

<sup>2</sup> The projects in this category are dual fuel, with either gas or oil as the primary fuel

- 2015 values include the 114 MW of generation that has gone commercial in 2015
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

# Actual and Projected Annual Generator Capacity Additions By State



	2015	2016	2017	2018	2019	2020	Total MW	% of Total <sup>1</sup>
<b>Vermont</b>	3	65	0	0	30	97	195	1.7
<b>Rhode Island</b>	27	51	0	0	1,661	0	1,739	15.3
<b>New Hampshire</b>	81	0	79	0	0	0	160	1.4
<b>Maine</b>	52	501	726	488	999	601	3,367	29.6
<b>Massachusetts</b>	10	53	1,560	1,185	334	870	4,012	35.3
<b>Connecticut</b>	84	121	0	1,631	63	0	1,899	16.7
<b>Totals</b>	<b>257</b>	<b>791</b>	<b>2,365</b>	<b>3,304</b>	<b>3,087</b>	<b>1,568</b>	<b>11,372</b>	<b>100.0</b>

<sup>1</sup> Sum may not equal 100% due to rounding

- 2015 values include the 114 MW of generation that has gone commercial in 2015

# 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	1	37	0	0	1	37
Hydro	5	35	0	0	5	35
Landfill Gas	1	2	0	0	1	2
Natural Gas	14	2,240	0	0	14	2,240
Natural Gas/Oil	18	4,790	0	0	18	4,790
Oil	0	0	0	0	0	0
Solar	5	90	1	10	4	80
Wind	36	4,064	6	285	30	3,779
<b>Total</b>	<b>80</b>	<b>11,258</b>	<b>7</b>	<b>295</b>	<b>73</b>	<b>10,963</b>

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- 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	2	100	0	0	2	100
Intermediate	24	5,396	0	0	24	5,396
Peaker	18	1,698	1	10	17	1,688
Wind Turbine	36	4,064	6	285	30	3,779
<b>Total</b>	<b>80</b>	<b>11,258</b>	<b>7</b>	<b>295</b>	<b>73</b>	<b>10,963</b>

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

# New Generation Projection

## *By Operating Type and Fuel Type*

Fuel Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	37	1	37	0	0	0	0	0	0
Hydro	5	35	0	0	4	10	1	25	0	0
Landfill Gas	1	2	0	0	0	0	1	2	0	0
Natural Gas	14	2,240	1	63	11	2,098	2	79	0	0
Natural Gas/Oil	18	4,790	0	0	9	3,288	9	1,502	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	5	90	0	0	0	0	5	90	0	0
Wind	36	4,064	0	0	0	0	0	0	36	4,064
<b>Total</b>	<b>80</b>	<b>11,258</b>	<b>2</b>	<b>100</b>	<b>24</b>	<b>5,396</b>	<b>18</b>	<b>1,698</b>	<b>36</b>	<b>4,064</b>

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel

# FORWARD CAPACITY MARKET



# Capacity Supply Obligation FCA 6

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	2,001.510	1,918.662	-82.848	1,368.608	-550.054	1,271.984	-96.624	1,085.347	-186.64	842.791	-242.56	789.366	-53.425	638.393	-150.973
	Passive Demand	1,643.334	1,553.054	-90.280	1,521.535	-31.519	1,521.535	0.000	1,516.504	-5.03	1,700.586	184.08	1,694.766	-5.82	1,687.458	-7.308
<b>Demand Total</b>		<b>3,644.844</b>	<b>3,471.716</b>	<b>-173.128</b>	<b>2,890.143</b>	<b>-581.573</b>	<b>2,793.519</b>	<b>-96.624</b>	<b>2,601.851</b>	<b>-191.67</b>	<b>2,543.377</b>	<b>-58.47</b>	<b>2,484.132</b>	<b>-59.245</b>	<b>2,325.851</b>	<b>-158.281</b>
Generator	Non-Intermittent	29,866.098	27,957.613	-1,908.485	28,121.731	164.118	28,343.440	221.709	28,442.424	98.98	28,727.16	284.73	28,881.019	153.859	28,971.511	90.492
	Intermittent	891.069	840.563	-50.506	827.047	-13.516	828.252	1.205	829.219	0.97	820.743	-8.48	777.924	-42.819	754.101	-23.823
<b>Generator Total</b>		<b>30,757.167</b>	<b>28,798.176</b>	<b>-1,958.991</b>	<b>28,948.778</b>	<b>150.602</b>	<b>29,171.692</b>	<b>222.914</b>	<b>29,271.643</b>	<b>99.95</b>	<b>29,547.9</b>	<b>276.26</b>	<b>29,658.943</b>	<b>111.043</b>	<b>29,725.612</b>	<b>66.669</b>
<b>Import Total</b>		<b>1,924.000</b>	<b>1,768.111</b>	<b>-155.889</b>	<b>1,768.111</b>	<b>0.000</b>	<b>1,641.821</b>	<b>-126.290</b>	<b>1,616.821</b>	<b>-25.00</b>	<b>1,399.037</b>	<b>-217.78</b>	<b>1,337.037</b>	<b>-62</b>	<b>1,337.037</b>	<b>0</b>
<b>***Grand Total</b>		<b>36,326.011</b>	<b>34,038.003</b>	<b>-2,288.008</b>	<b>33,607.032</b>	<b>-430.971</b>	<b>33,607.032</b>	<b>0.000</b>	<b>33,490.315</b>	<b>-116.72</b>	<b>33,490.32</b>	<b>0.00</b>	<b>33,480.112</b>	<b>-10.208</b>	<b>33,388.5</b>	<b>-91.612</b>
<b>Net ICR (NICR)</b>		<b>33,456</b>	<b>33,456</b>	<b>0</b>	<b>33,456</b>	<b>0</b>	<b>33,456</b>	<b>0</b>	<b>33,114</b>	<b>-342</b>	<b>33,114</b>	<b>0.00</b>	<b>33,391</b>	<b>277</b>	<b>33,391</b>	<b>0</b>

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

\*\* Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

\*\*\* Grand Total reflects both CSO Grand Total and the net total of the Change Column.



# Capacity Supply Obligation FCA 7

Resource Type	Resource Type	FCA	Proration		Annual Bilateral for ARA 1		ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	**Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Demand	Active Demand	1,116.698	1,043.719	-72.979	944.27	-99.45	932.721	-11.549	781.206	-151.52						
	Passive Demand	1,631.335	1,519.740	-111.595	1,519.311	-0.43	1,543.793	24.482	1544.276	0.48						
<b>Demand Total</b>		<b>2,748.033</b>	<b>2,563.459</b>	<b>-184.574</b>	<b>2,463.581</b>	<b>-99.88</b>	<b>2,476.514</b>	<b>12.933</b>	<b>2,325.482</b>	<b>-151.03</b>						
Generator	Non-Intermittent	30,704.578	28,146.837	-2,557.741	28,127.044	-19.79	28,523.002	395.958	28,307.339	-215.66						
	Intermittent	936.913	893.710	-43.203	903.244	9.53	913.083	9.839	838.626	-74.46						
<b>Generator Total</b>		<b>31,641.491</b>	<b>29,040.547</b>	<b>-2,600.944</b>	<b>29,030.288</b>	<b>-10.26</b>	<b>29,436.085</b>	<b>405.797</b>	<b>29,145.965</b>	<b>-290.12</b>						
<b>Import Total</b>		<b>1,830.000</b>	<b>1,606.862</b>	<b>-223.138</b>	<b>1,606.862</b>	<b>0.00</b>	<b>1,616.401</b>	<b>9.539</b>	<b>1576.401</b>	<b>-40.00</b>						
<b>***Grand Total</b>		<b>36,219.524</b>	<b>33,210.868</b>	<b>-3,008.656</b>	<b>33,100.731</b>	<b>-110.14</b>	<b>33,529.000</b>	<b>428.269</b>	<b>33,047.848</b>	<b>-481.15</b>						
<b>Net ICR (NICR)</b>		<b>32,968</b>	<b>32,968</b>	<b>0</b>	<b>33,529</b>	<b>561</b>	<b>33,529</b>	<b>0</b>	<b>33,529</b>	<b>0.00</b>						

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

\*\* Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

\*\*\* Grand Total reflects both CSO Grand Total and the net total of the Change Column.



# Capacity Supply Obligation FCA 8

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1			ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	
Demand	Active Demand	1,080.079	887.493	-192.59	896.202	8.709									
	Passive Demand	1,960.517	1,958.874	-1.64	1,956.663	-2.211									
<b>Demand Total</b>		<b>3,040.596</b>	<b>2,846.367</b>	<b>-194.23</b>	<b>2,852.865</b>	<b>6.498</b>									
Generator	Non-Intermittent	28,547.813	28,523.796	-24.02	28,667.121	143.325									
	Intermittent	876.925	898.955	22.03	921.922	22.967									
<b>Generator Total</b>		<b>29,424.738</b>	<b>29,422.751</b>	<b>-1.99</b>	<b>29,589.043</b>	<b>166.292</b>									
<b>Import Total</b>		<b>1,237.034</b>	<b>1,237.034</b>	<b>0.00</b>	<b>1,375.53</b>	<b>138.496</b>									
<b>***Grand Total</b>		<b>33,702.368</b>	<b>33,506.152</b>	<b>-196.22</b>	<b>33,817.438</b>	<b>311.286</b>									
<b>Net ICR (NICR)</b>		<b>33,855</b>	<b>34,061</b>	<b>206.00</b>	<b>34,061</b>	<b>0</b>									

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

\*\* Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

\*\*\* Grand Total reflects both CSO Grand Total and the net total of the Change Column.



# Capacity Supply Obligation FCA 9

Resource Type	Resource Type	FCA	Annual Bilateral for ARA 1			ARA 1		Annual Bilateral for ARA 2		ARA 2		Annual Bilateral for ARA 3		ARA 3	
		*CSO	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	CSO	Change	
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	
Demand	Active Demand	647.26													
	Passive Demand	2,156.151													
<b>Demand Total</b>		<b>2,803.411</b>													
Generator	Non-Interrmittent	29,550.564													
	Interrmittent	891.616													
<b>Generator Total</b>		<b>30,442.18</b>													
<b>Import Total</b>		<b>1,449</b>													
<b>***Grand Total</b>		<b>34,694.591</b>													
<b>Net ICR (NICR)</b>		<b>34,189</b>													

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

\*\* Change columns contain the changes in CSO amount resulting from the specific FCM Event as well as adjustments for Delisted MW released according to MR 1, Section 13.2.5.2, and changes that occurred (terminations, etc.) prior to the event reported in the column.

\*\*\* Grand Total reflects both CSO Grand Total and the net total of the Change Column.



# Active/Passive Demand Response

## CSO Totals by Commitment Period

Commitment Period	Active/ Passive	Existing	New	Grand Total
2010-11	Active	1246.399	603.675	1850.074
	Passive	119.211	584.277	703.488
	<b>Grand Total</b>	<b>1365.61</b>	<b>1187.952</b>	<b>2553.562</b>
2011-12	Active	1768.392	184.99	1953.382
	Passive	719.98	263.25	983.23
	<b>Grand Total</b>	<b>2488.372</b>	<b>448.24</b>	<b>2936.612</b>
2012-13	Active	1726.548	98.227	1824.775
	Passive	861.602	211.261	1072.863
	<b>Grand Total</b>	<b>2588.15</b>	<b>309.488</b>	<b>2897.638</b>
2013-14	Active	1794.195	257.341	2051.536
	Passive	1040.113	257.793	1297.906
	<b>Grand Total</b>	<b>2834.308</b>	<b>515.134</b>	<b>3349.442</b>
2014-15	Active	2062.196	41.945	2104.141
	Passive	1264.641	221.072	1485.713
	<b>Grand Total</b>	<b>3326.837</b>	<b>263.017</b>	<b>3589.854</b>
2015-16	Active	1935.406	66.104	2001.51
	Passive	1395.885	247.449	1643.334
	<b>Grand Total</b>	<b>3331.291</b>	<b>313.553</b>	<b>3644.844</b>
2016-17	Active	1116.468	0.23	1116.698
	Passive	1386.56	244.775	1631.335
	<b>Grand Total</b>	<b>2503.028</b>	<b>245.005</b>	<b>2748.033</b>
2017-18	Active	1066.593	13.486	1080.079
	Passive	1619.147	341.37	1960.517
	<b>Grand Total</b>	<b>2685.74</b>	<b>354.856</b>	<b>3040.596</b>
2018-19	Active	565.866	81.394	647.26
	Passive	1870.549	285.602	2156.151
	<b>Grand Total</b>	<b>2436.415</b>	<b>366.996</b>	<b>2803.411</b>

# RELIABILITY COSTS – NET COMMITMENT PERIOD COMPENSATION (NCPC) OPERATING COSTS



# What are Daily NCPC Payments?

- 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

<p>1<sup>st</sup> Contingency NCPC Payments</p>	<p>Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally</p>
<p>2<sup>nd</sup> Contingency NCPC Payments</p>	<p>Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2<sup>nd</sup> Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR)</p>
<p>Voltage NCPC Payments</p>	<p>Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations</p>
<p>Distribution NCPC Payments</p>	<p>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</p>
<p>Delisted Units</p>	<p>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</p>
<p>OATT</p>	<p>Open Access Transmission Tariff</p>



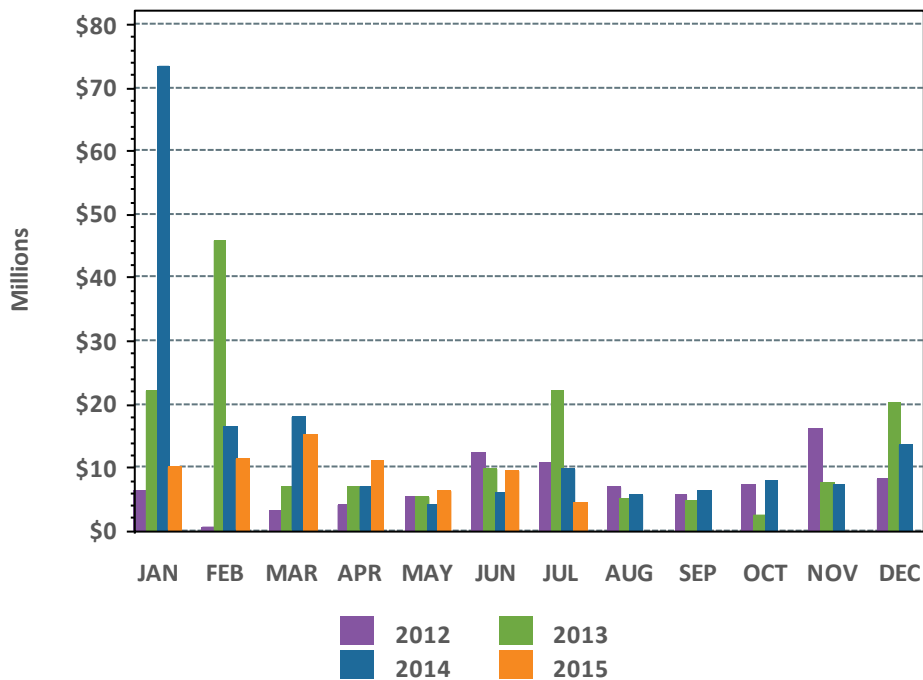
# Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 1 <sup>st</sup> Contingency	Market	DA 1 <sup>st</sup> C (excluding at external nodes) is allocated to system DALO. RT 1 <sup>st</sup> C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1 <sup>st</sup> Contingency	Market	DA 1 <sup>st</sup> C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2 <sup>nd</sup> Contingency	Market	DA and RT 2 <sup>nd</sup> C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service
System – Other	Market	Includes GPA, Min Generation Emergency, and Generator and DARD NCPC

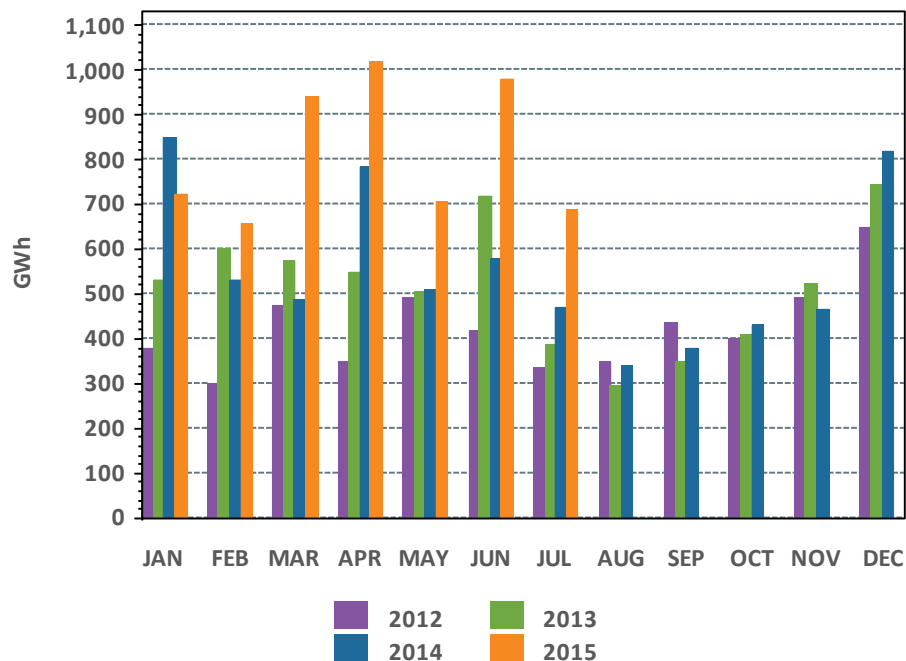


# Year-Over-Year Total NCPC Dollars and Energy

NCPC Dollars



NCPC Energy\*

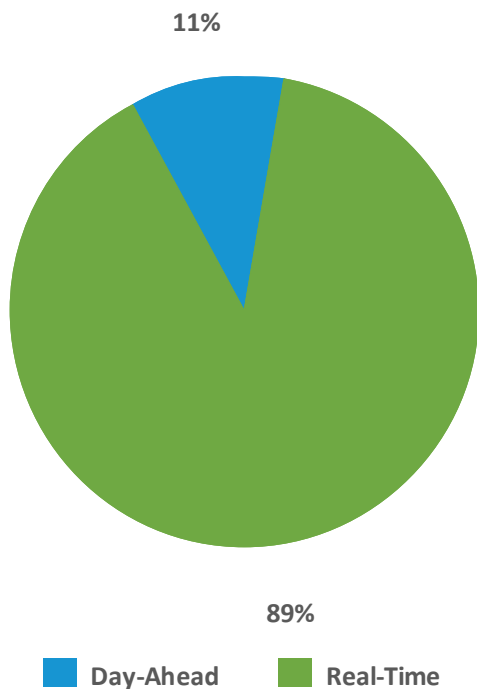


\* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1<sup>st</sup> Contingency, 2<sup>nd</sup> Contingency, Voltage, and RT Distribution) are reflected.

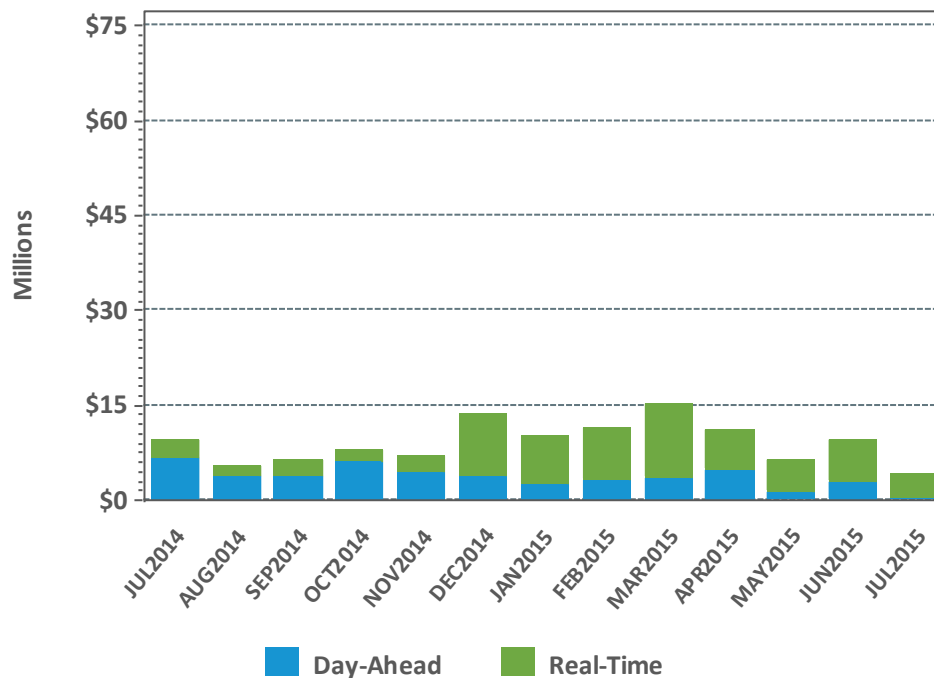


# DA and RT NCPC Charges

JUL-15 Total = \$4.32 M

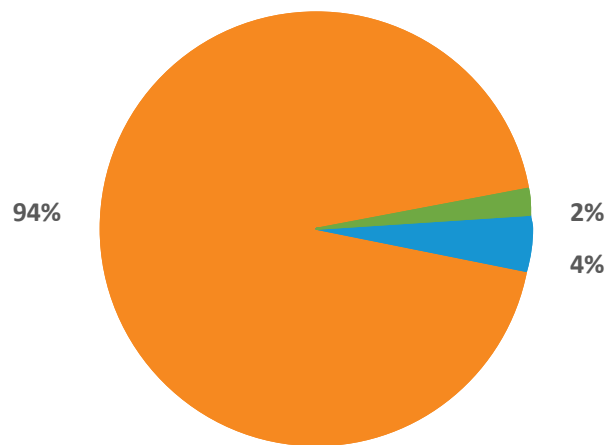


Last 13 Months

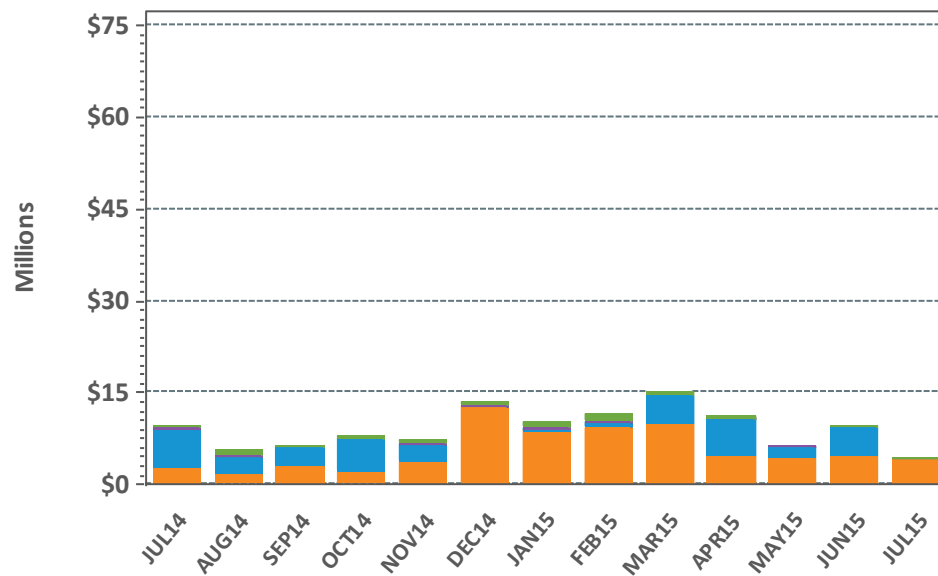


# NCPC Charges by Type

JUL-15 Total = \$4.32 M



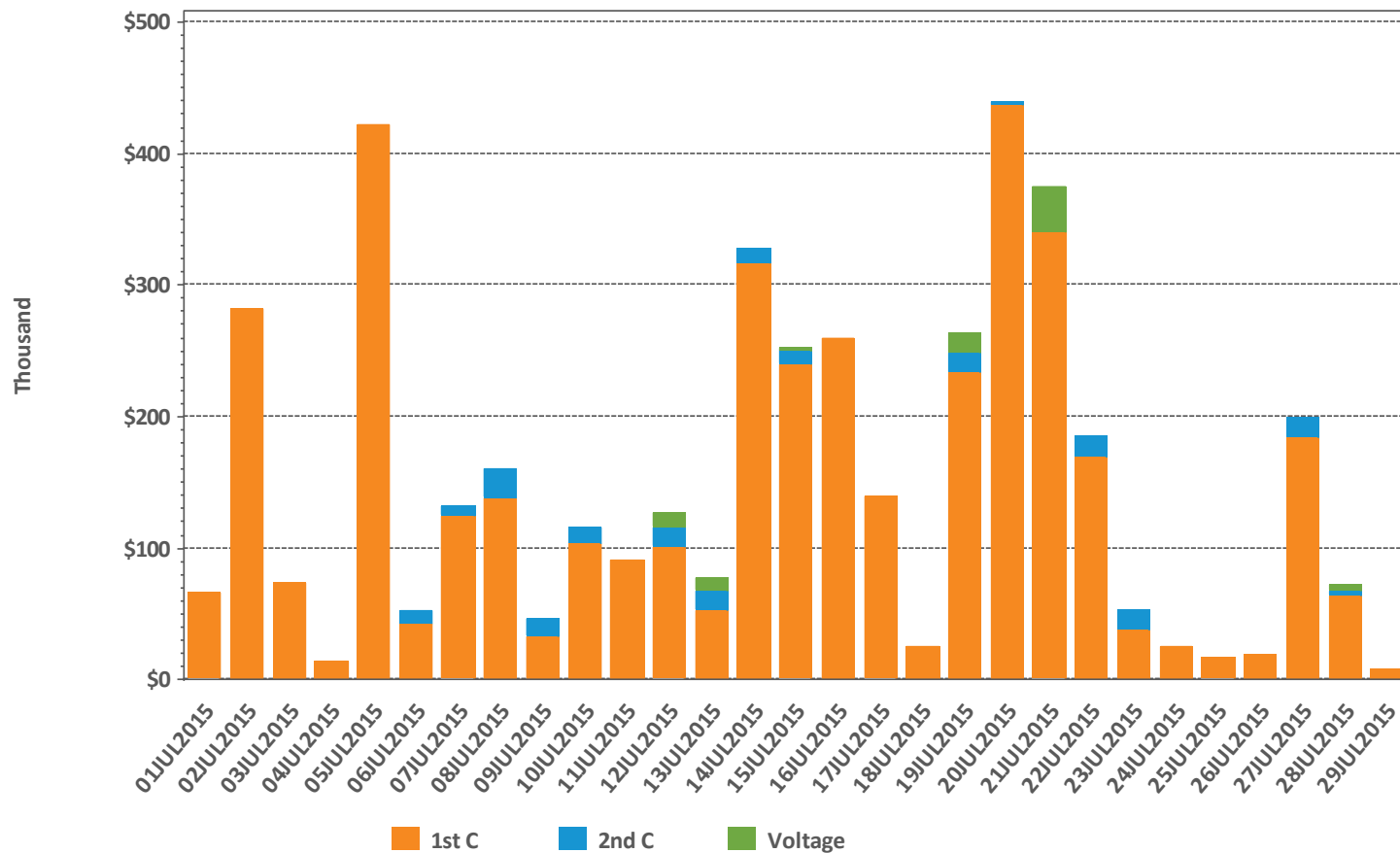
Last 13 Months



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

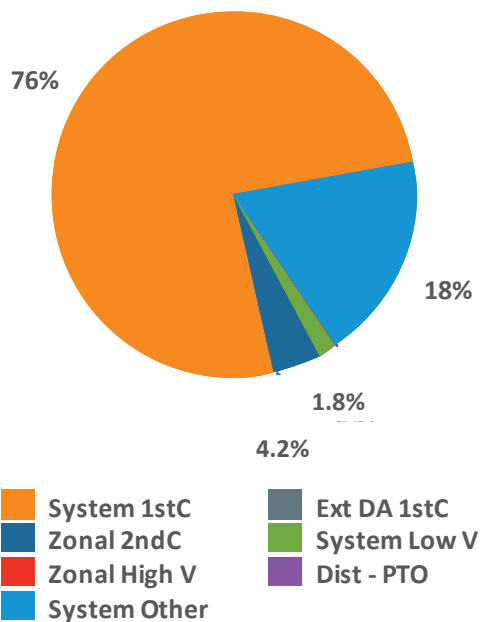


# Daily NCPC Charges by Type

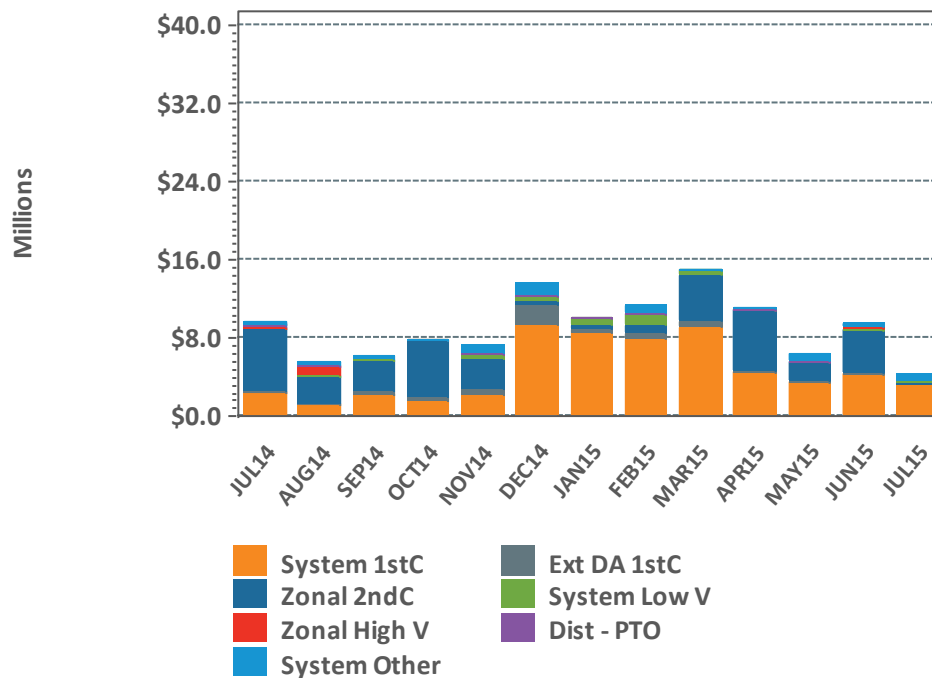


# NCPC Charges by Allocation

JUL-15 Total = \$4.32 M

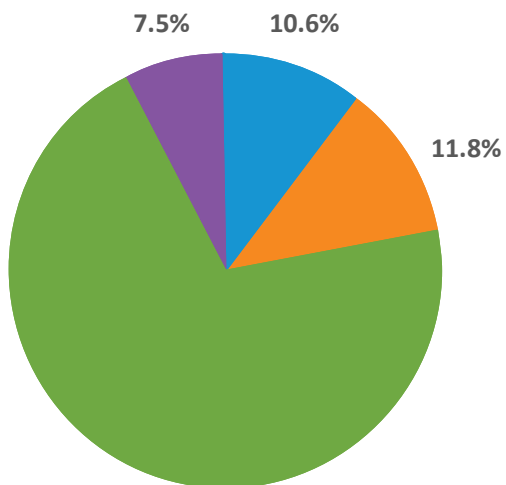


Last 13 Months



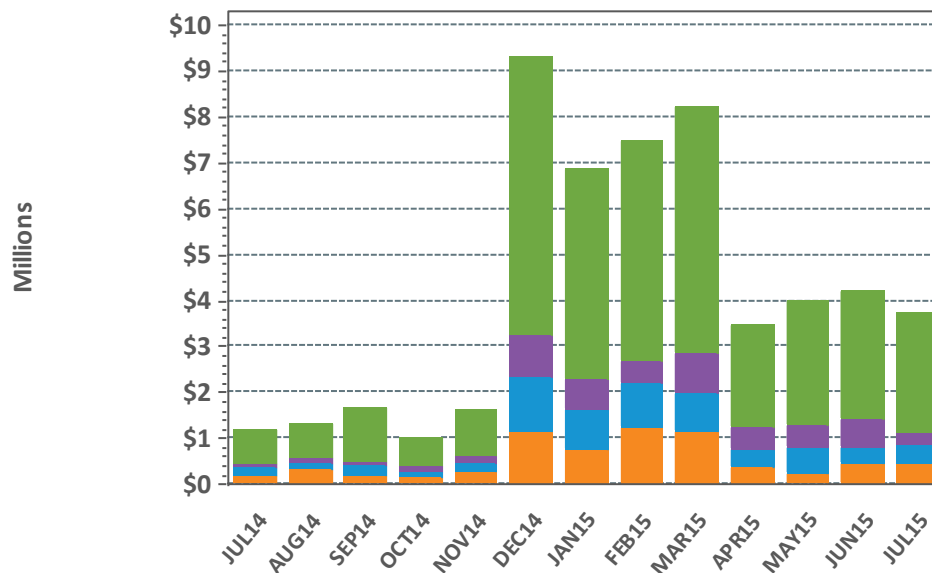
# RT First Contingency Charges by Deviation Type

JUL-15 Total = \$3.71 M

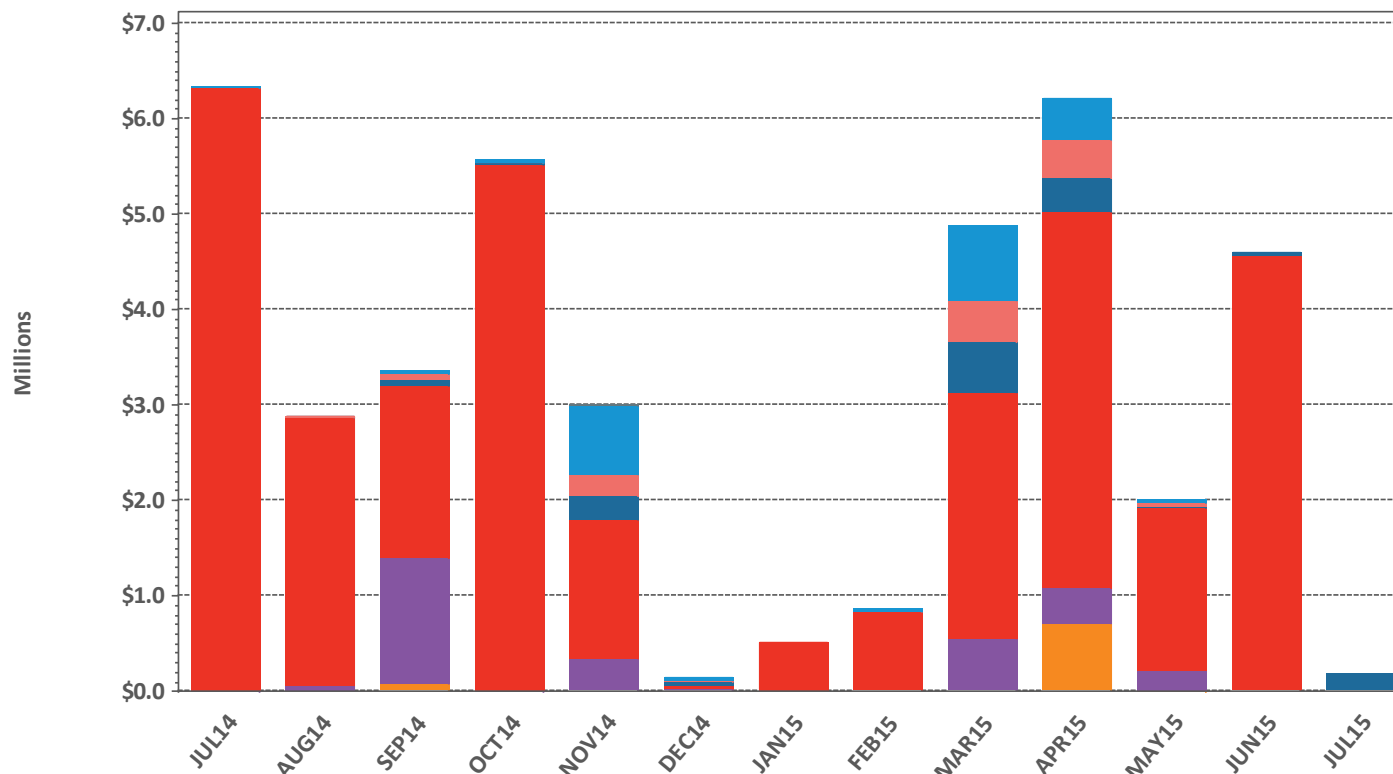


Gen – Generator deviations  
 Inc – Increment Offer deviations  
 Imp – Import deviations  
 Load – Load obligation deviations

Last 13 Months



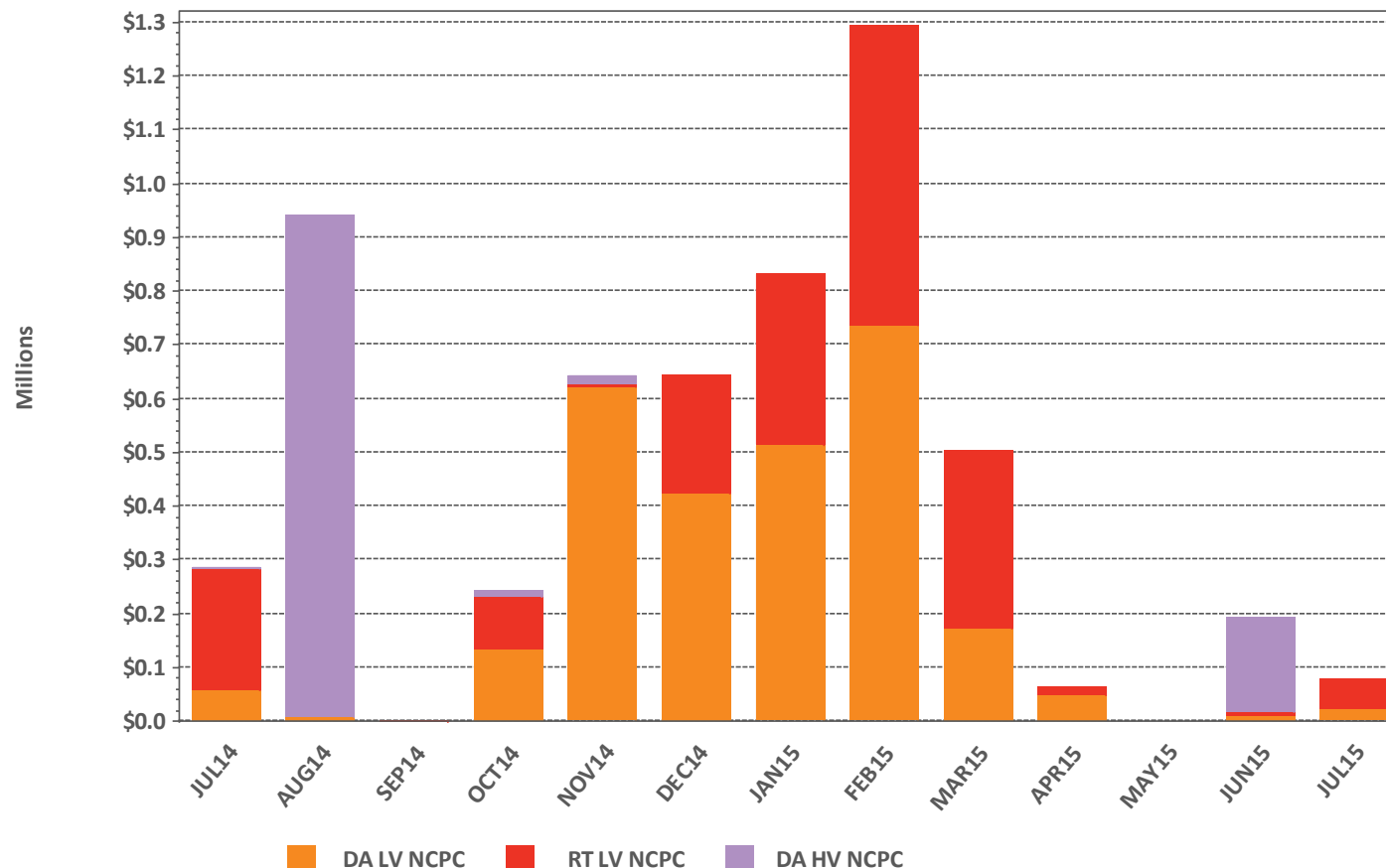
# LSCPR Charges by Zone



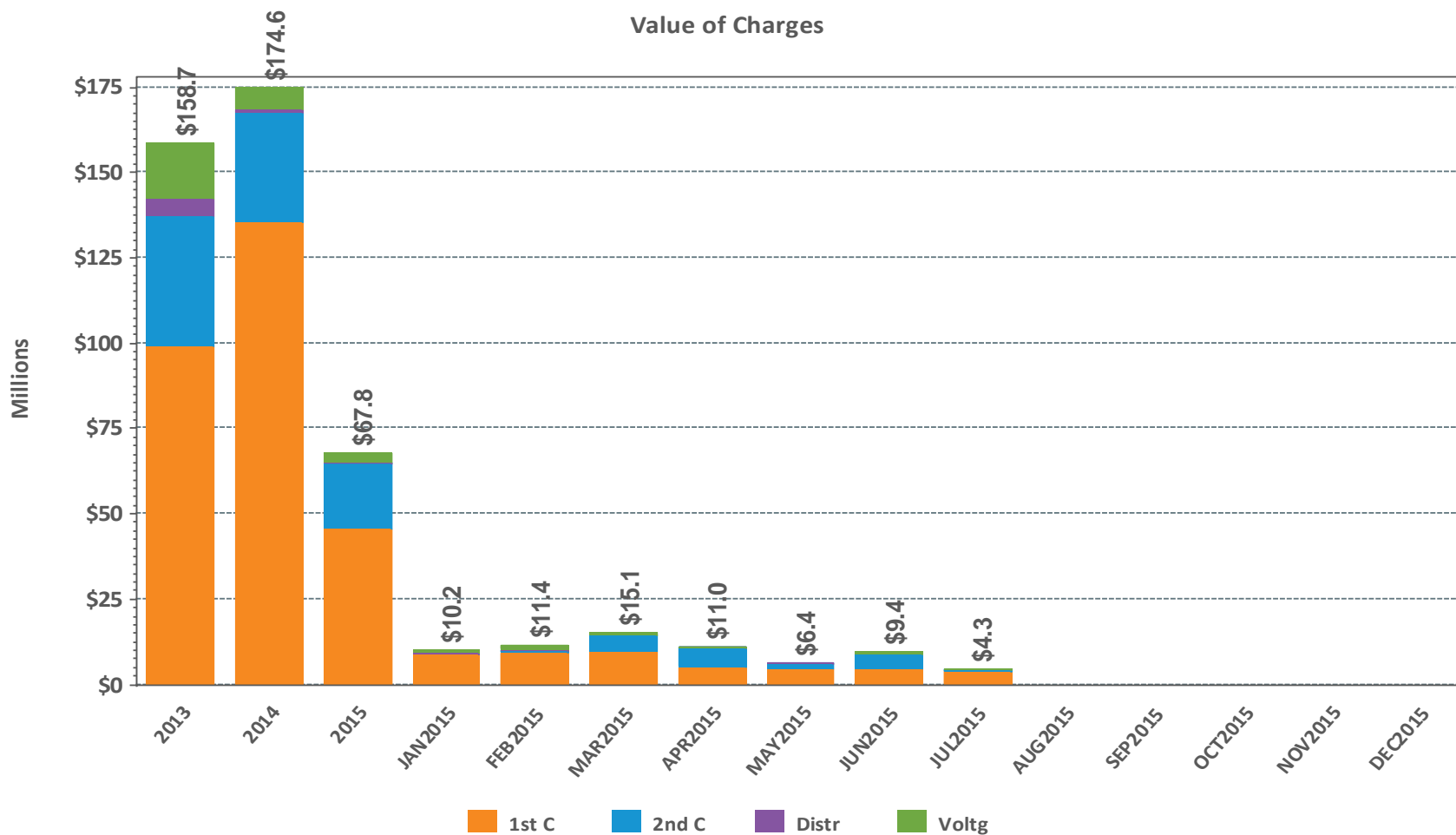
<span style="color: orange;">■</span> CT	<span style="color: purple;">■</span> ME	<span style="color: red;">■</span> NEMA	<span style="color: blue;">■</span> NH
<span style="color: pink;">■</span> RI	<span style="color: lightblue;">■</span> SEMA	<span style="color: green;">■</span> VT	<span style="color: grey;">■</span> WCMA

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

# NCPC Charges for Voltage Support and High Voltage Control

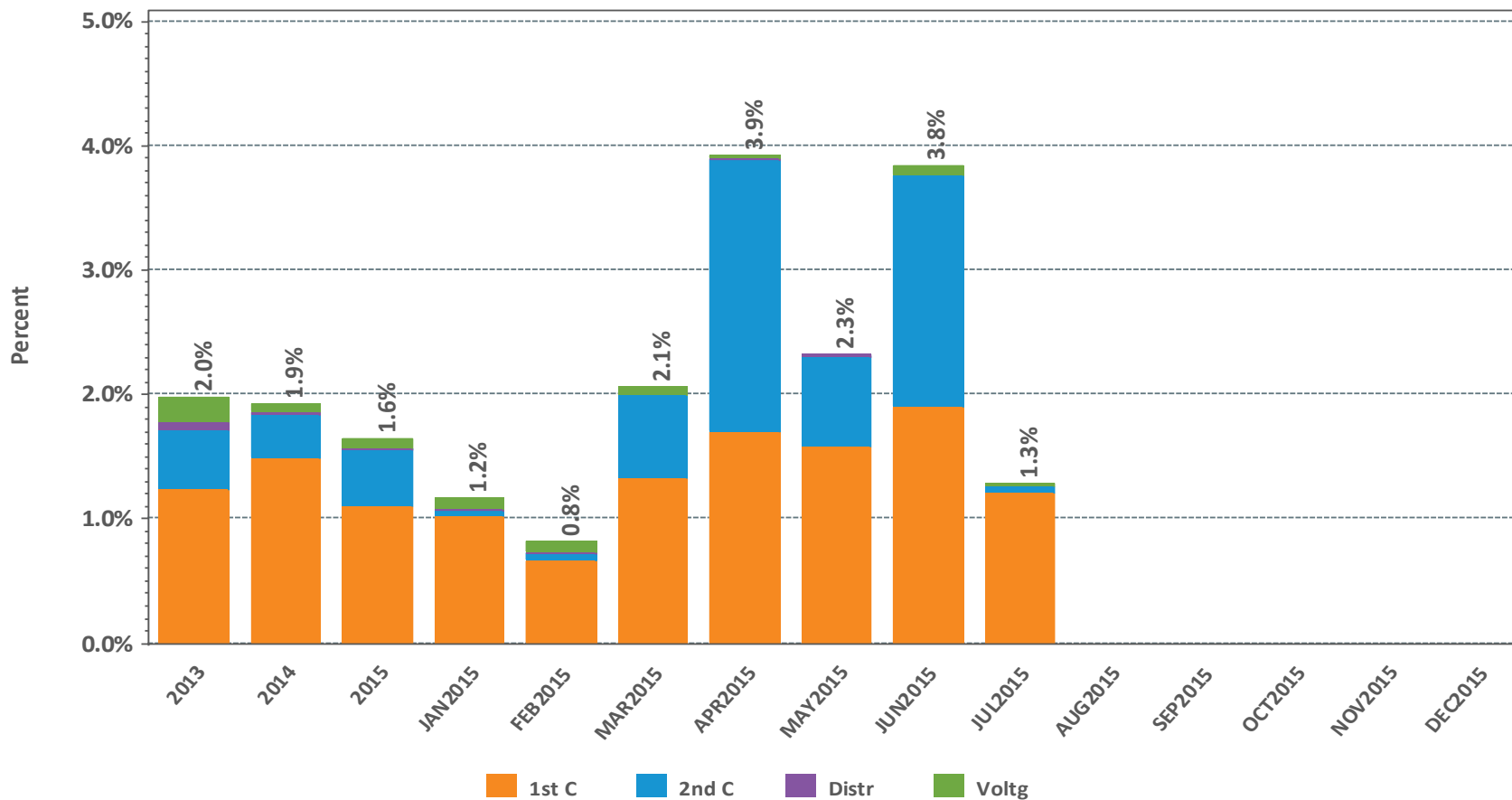


# NCPC Charges by Type



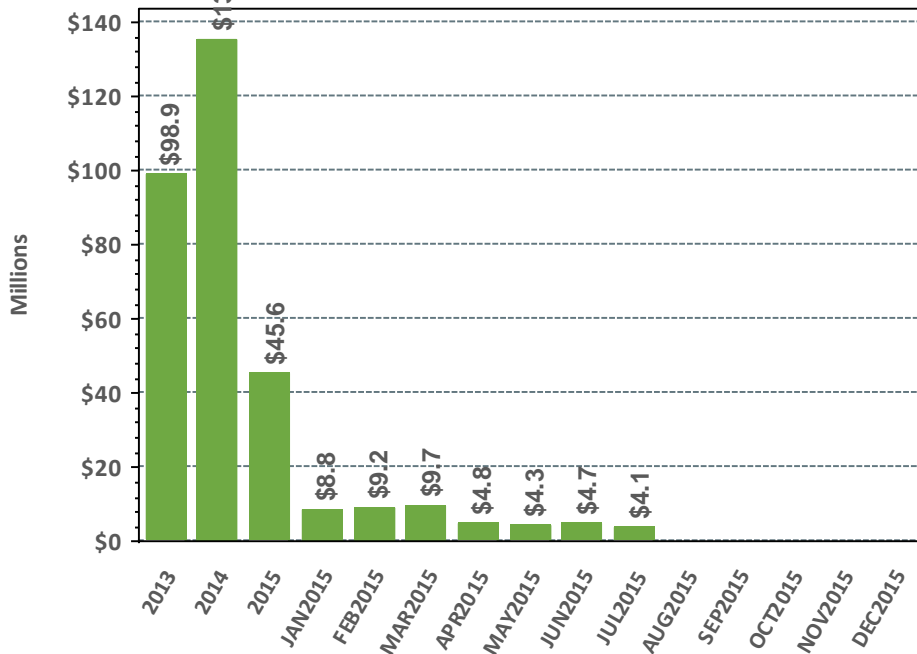
# NCPC Charges as Percent of Energy Market

NCPC By Type as Percent of Energy Market

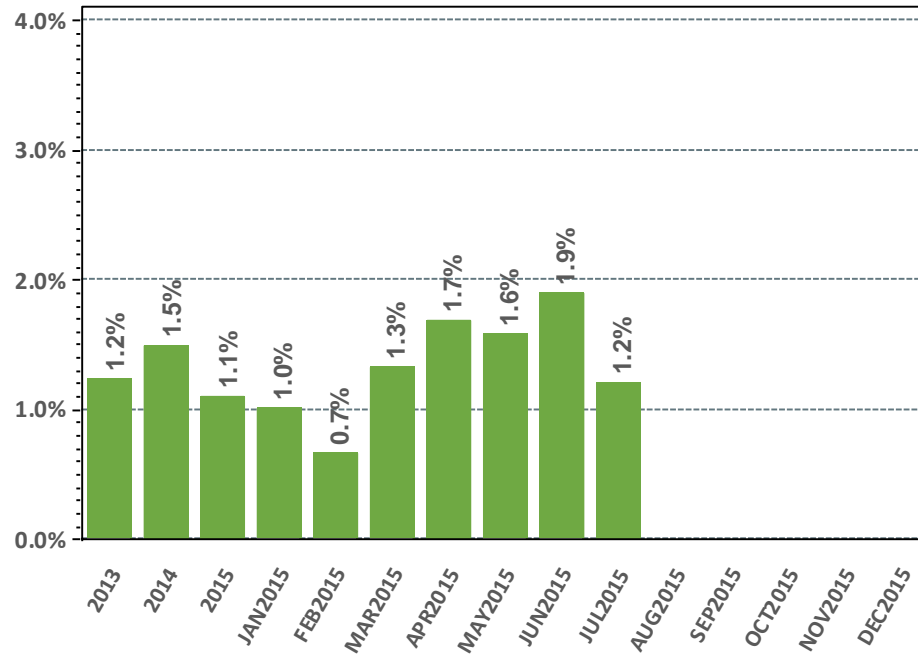


# First Contingency NCPC Charges

Value of Charges



% of Energy Market Value

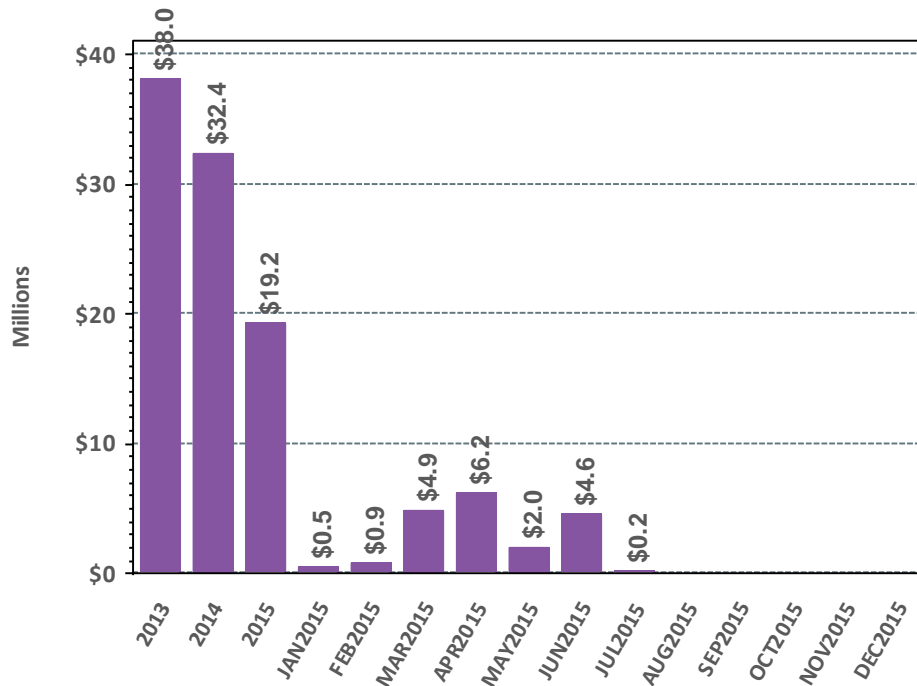


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

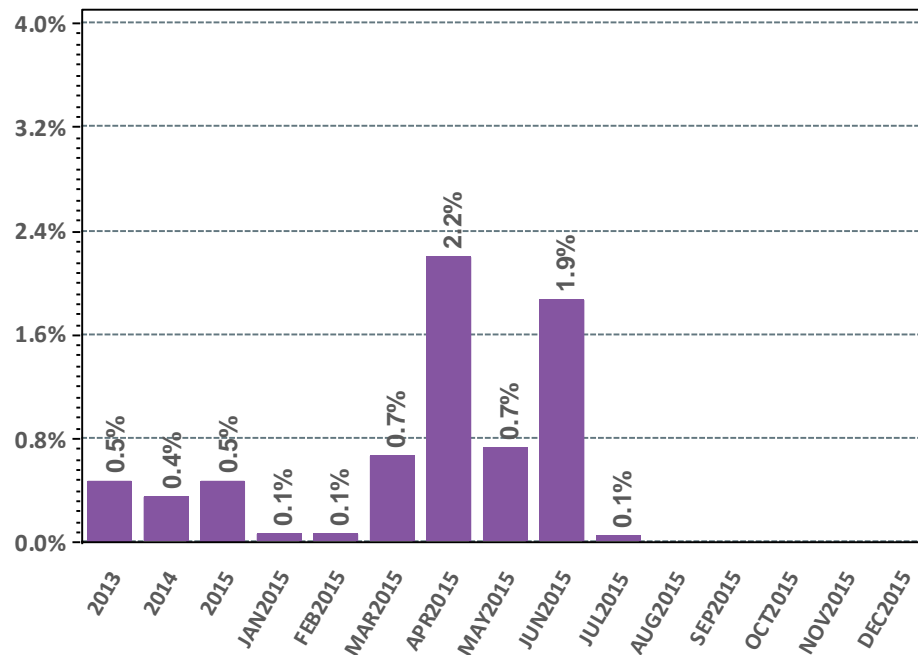


# Second Contingency NCPC Charges

Value of Charges



% of Energy Market Value

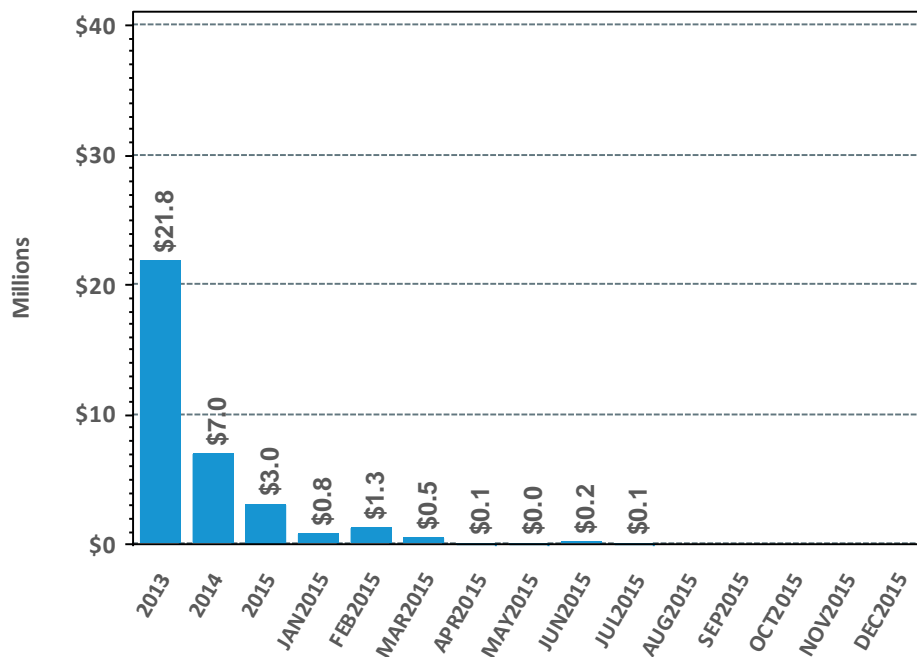


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

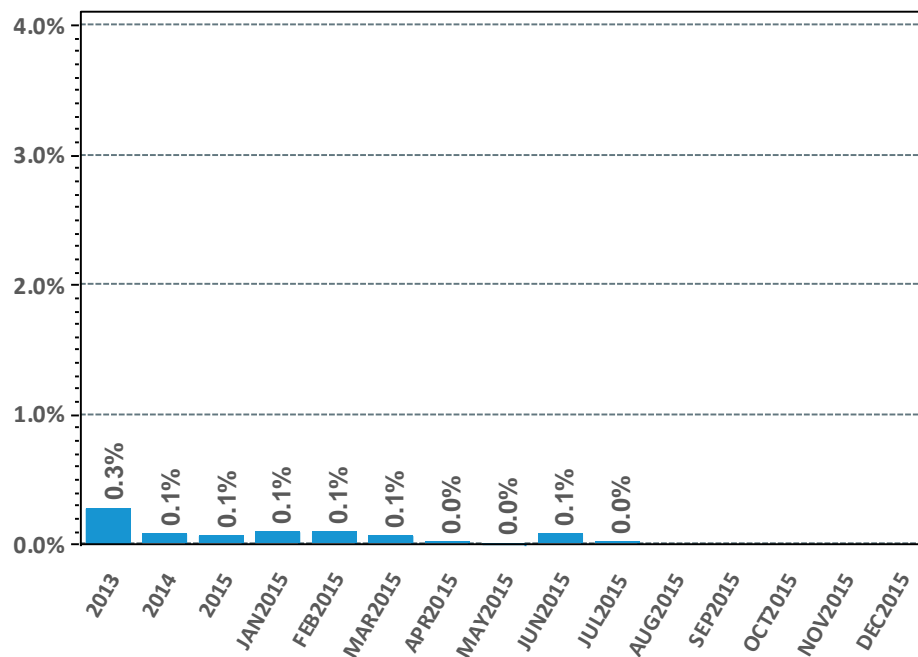


# Voltage and Distribution NCP Charges

Value of Charges



% of Energy Market Value



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



# DA vs. RT Pricing

## The following slides outline:

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



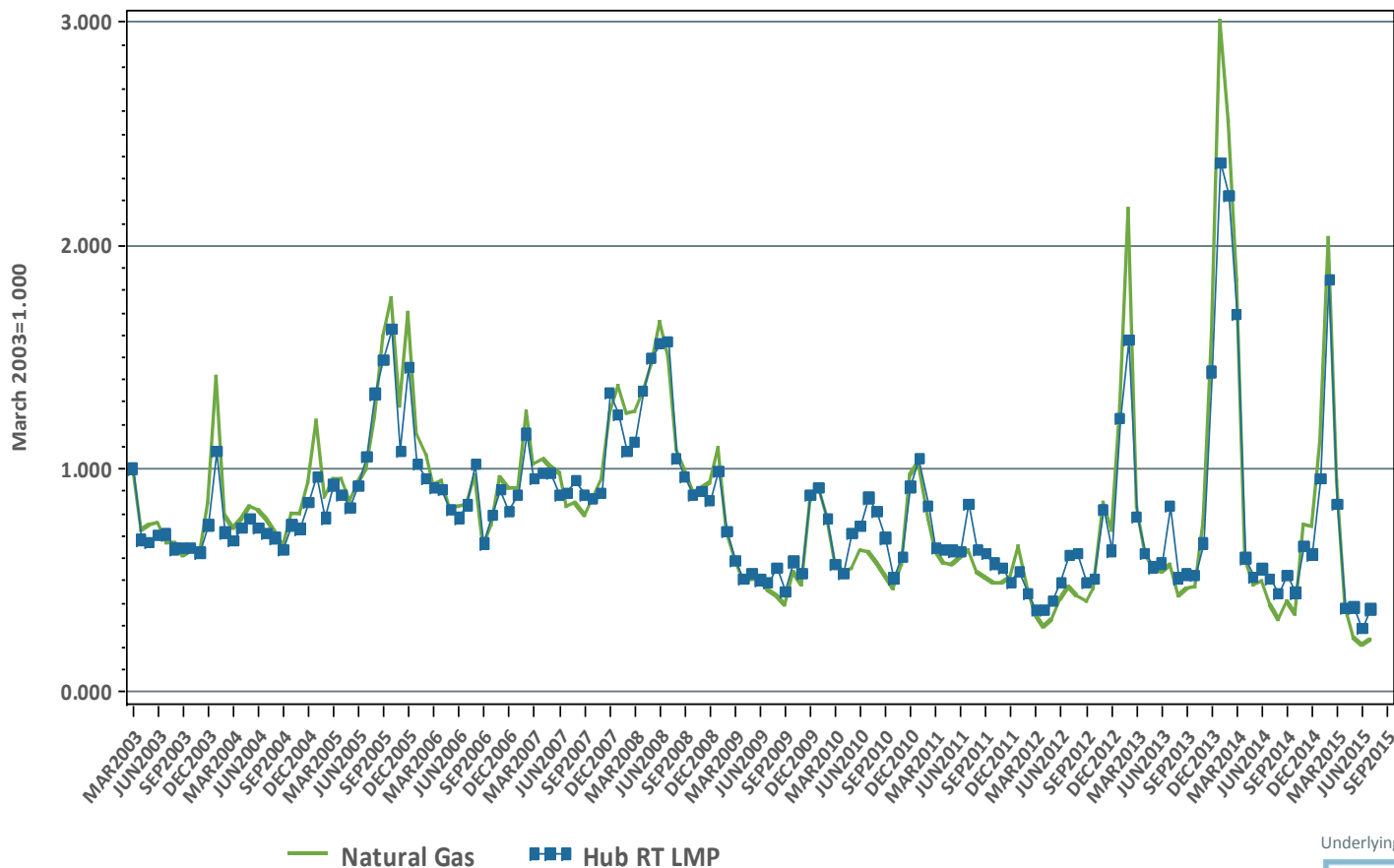
# DA vs. RT LMPs (\$/MWh)

## Arithmetic Average

Year 2013	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$56.90	\$55.43	\$54.48	\$55.98	\$55.36	\$57.80	\$57.02	\$56.38	\$56.43
Real-Time	\$56.32	\$55.90	\$53.23	\$55.15	\$55.08	\$56.10	\$56.43	\$56.12	\$56.06
RT Delta %	-1.0%	0.8%	-2.3%	-1.5%	-0.5%	-2.9%	-1.0%	-0.5%	-0.7%
Year 2014	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$64.98	\$64.10	\$61.95	\$64.12	\$63.82	\$64.98	\$64.71	\$64.66	\$64.57
Real-Time	\$64.03	\$63.11	\$59.04	\$61.48	\$61.60	\$63.34	\$63.45	\$63.29	\$63.32
RT Delta %	-1.5%	-1.5%	-4.7%	-4.1%	-3.5%	-2.5%	-2.0%	-2.1%	-1.9%

July-14	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$38.24	\$37.89	\$35.26	\$37.18	\$37.39	\$37.37	\$37.35	\$37.66	\$37.50
Real-Time	\$37.81	\$35.10	\$32.16	\$33.81	\$34.06	\$34.67	\$34.82	\$35.03	\$34.91
RT Delta %	-1.1%	-7.4%	-8.8%	-9.1%	-8.9%	-7.2%	-6.8%	-7.0%	-6.9%
July-15	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$25.72	\$26.22	\$25.39	\$25.92	\$25.95	\$25.48	\$25.57	\$25.91	\$25.78
Real-Time	\$25.63	\$25.91	\$24.91	\$25.43	\$25.46	\$25.33	\$25.46	\$25.66	\$25.56
RT Delta %	-0.3%	-1.2%	-1.9%	-1.9%	-1.9%	-0.6%	-0.4%	-1.0%	-0.8%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-32.8%	-30.8%	-28.0%	-30.3%	-30.6%	-31.8%	-31.5%	-31.2%	-31.3%
Yr over Yr RT	-32.2%	-26.2%	-22.6%	-24.8%	-25.2%	-26.9%	-26.9%	-26.7%	-26.8%

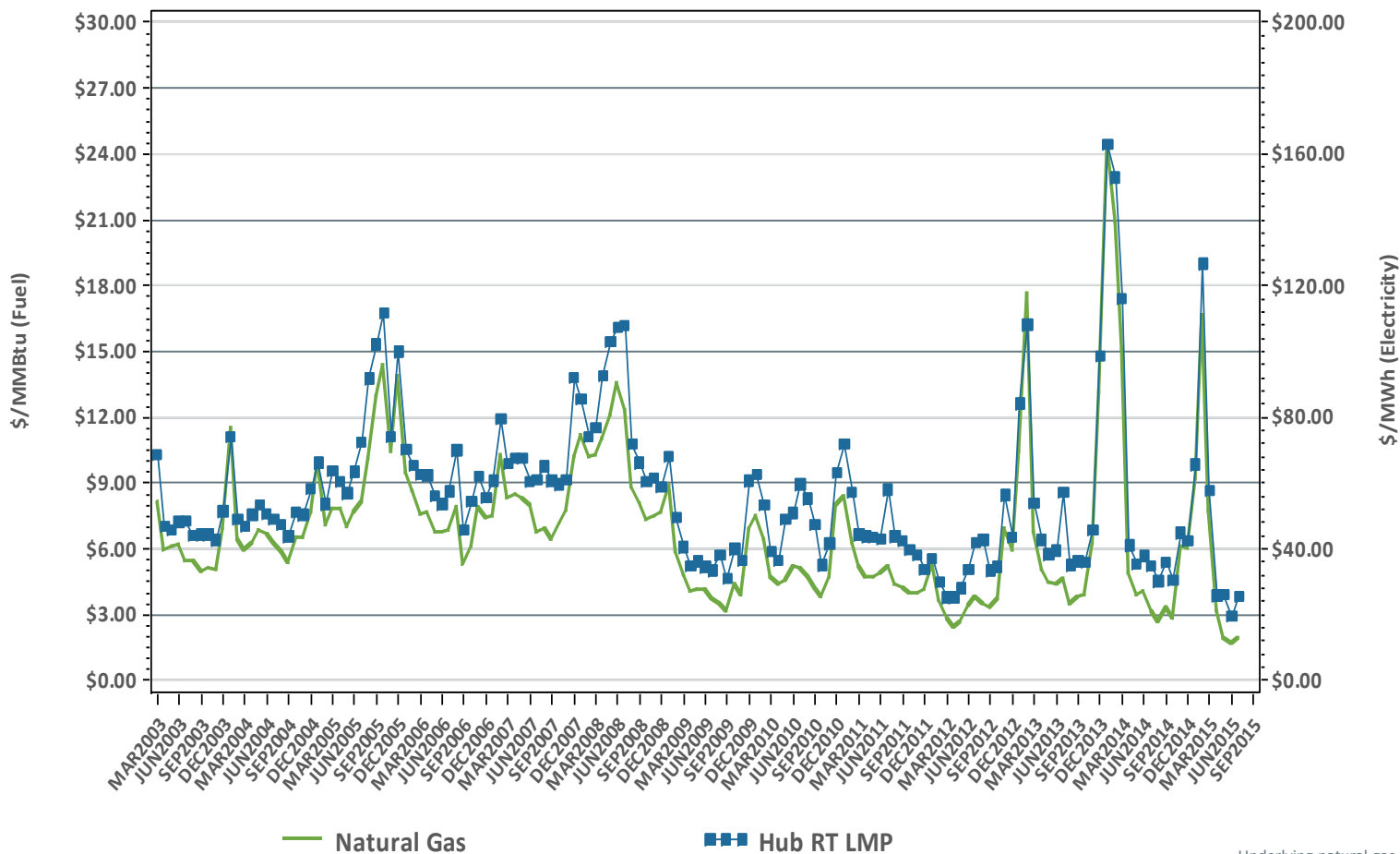
# Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:



# Monthly Average Fuel Price and RT Hub LMP

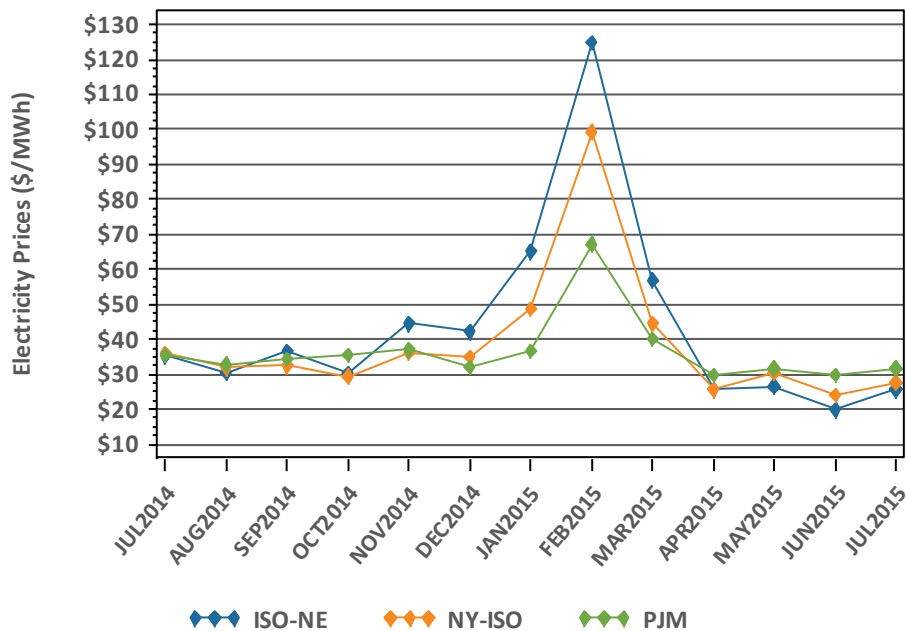


Underlying natural gas data furnished by:



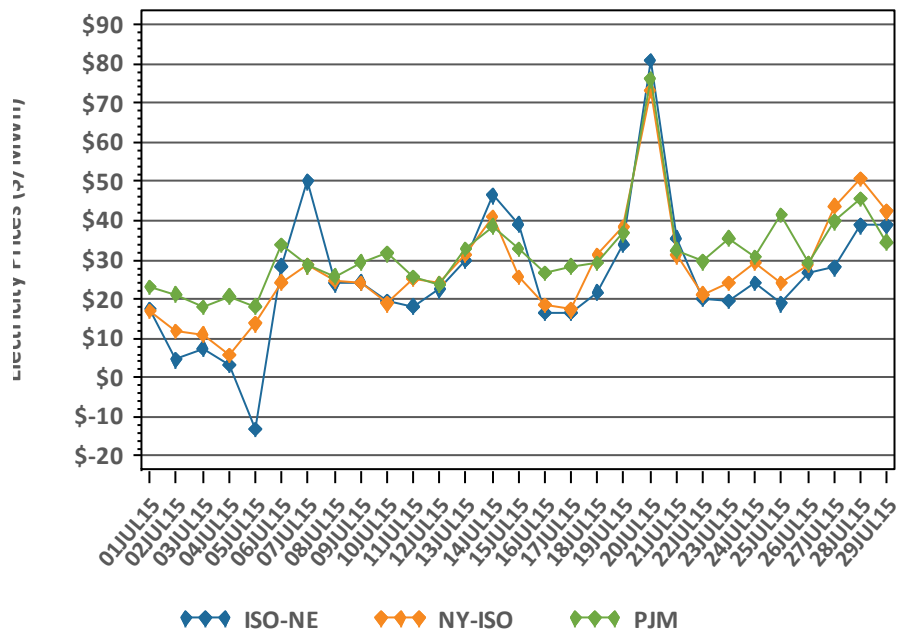
# New England, NY, and PJM Real Time Prices

Monthly, Last 13 Months



\*Note: Hourly average prices are shown.

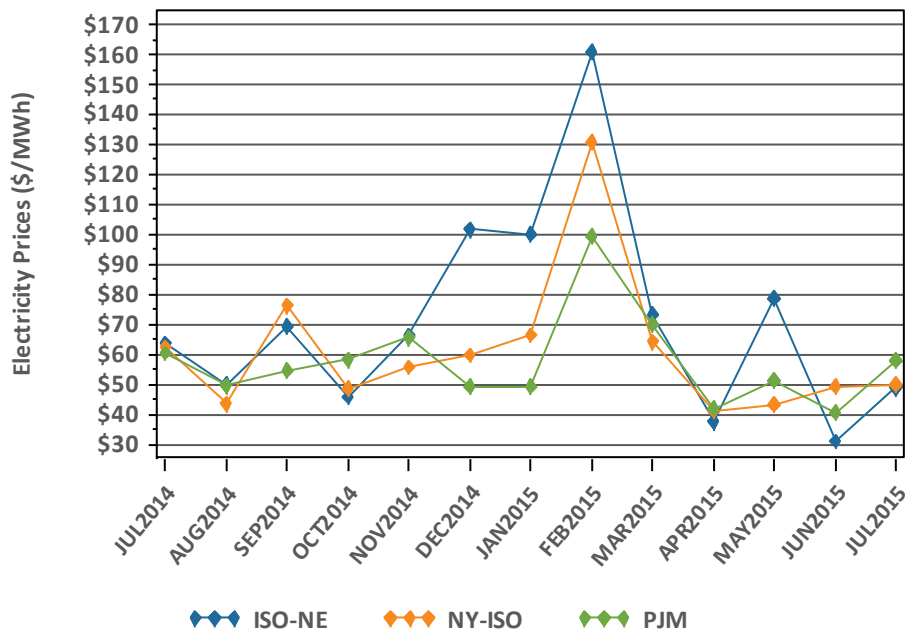
Daily: This Month



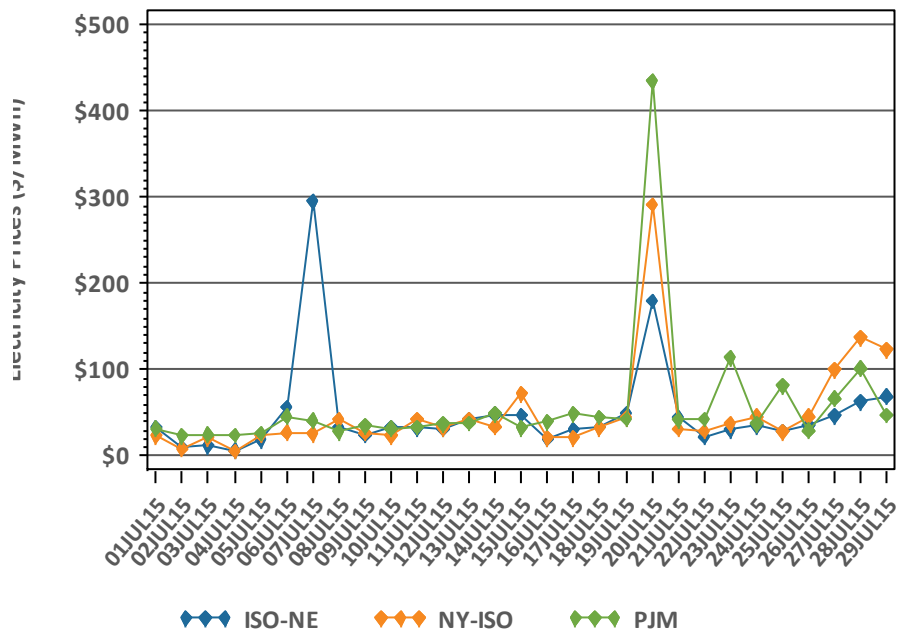
\*Note: Hourly average prices are shown.

# New England, NY, and PJM Real Time Prices (Peak Hour)

Monthly, Last 13 Months



Daily: This Month



\*Forecasted New England peak hour is reflected.



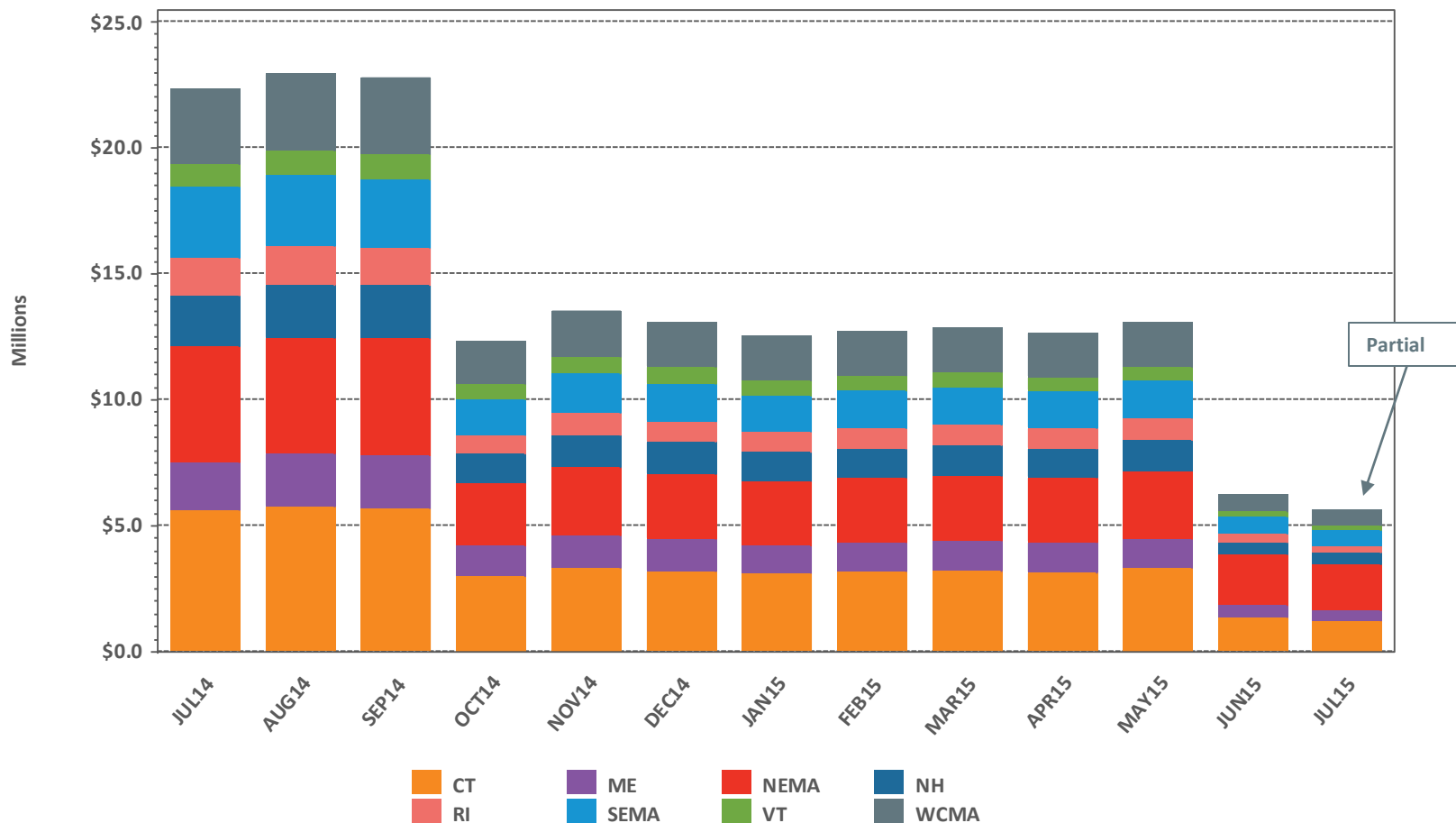
# Reserve Market Results – July 2015

- Maximum potential Forward Reserve Market payments of \$5.9M were reduced by credit reductions of \$99K, failure-to-reserve penalties of \$188K and failure-to-activate penalties of \$2K, resulting in a net payout of \$5.6M or 95% of maximum
  - Rest of System: \$2.22M/\$2.33M (95%)
  - Southwest Connecticut: \$0.37M/\$0.42M (89%)
  - Connecticut: \$1.45M/\$1.46M (~100%)
  - NEMA: \$1.56M/\$1.69M (92%)
- \$2.6M total Real-Time credits were reduced by \$1.2M in Forward Reserve Energy Obligation Charges for a net of \$1.3M in Real-Time Reserve payments
  - Rest of System: 82 hours, \$863K
  - Southwest Connecticut: 82 hours, \$345K
  - Connecticut: 82 hours, \$93K
  - NEMA: 82 hours, \$38K

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

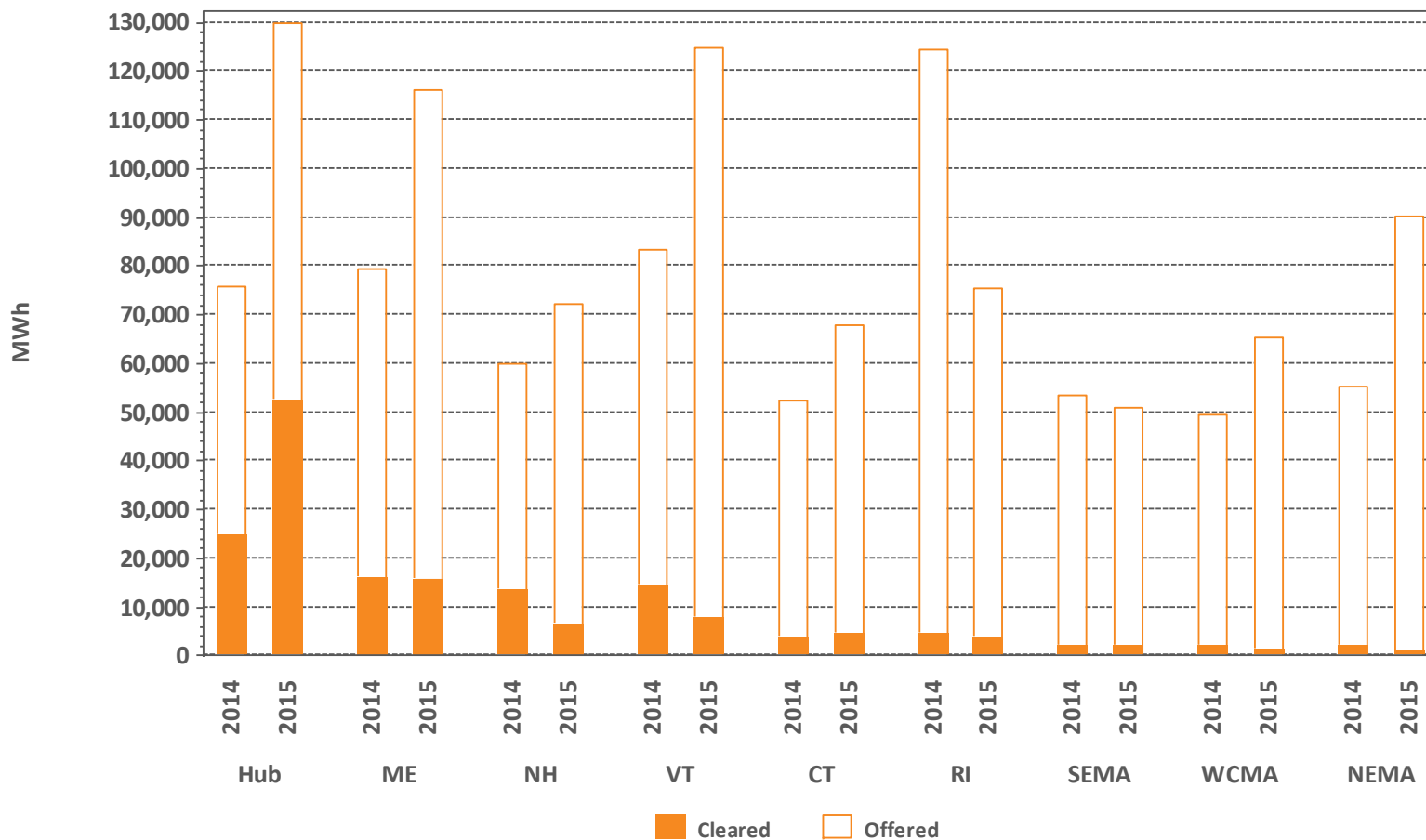
# LFRM Charges to Load by Load Zone (\$)

LFRM Charges by Zone, Last 13 Months



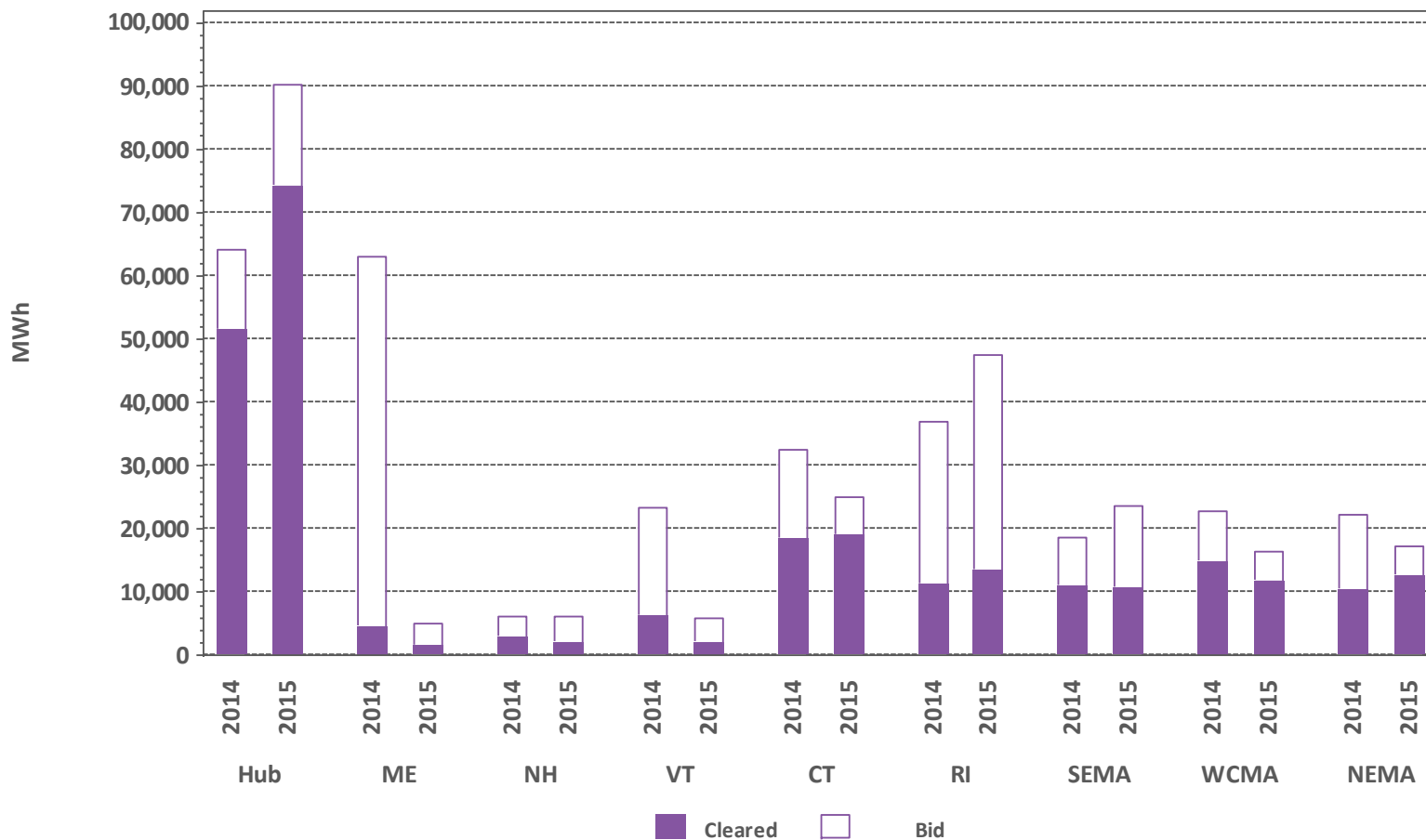
# Zonal Increment Offers and Cleared Amounts

July Monthly Totals by Zone



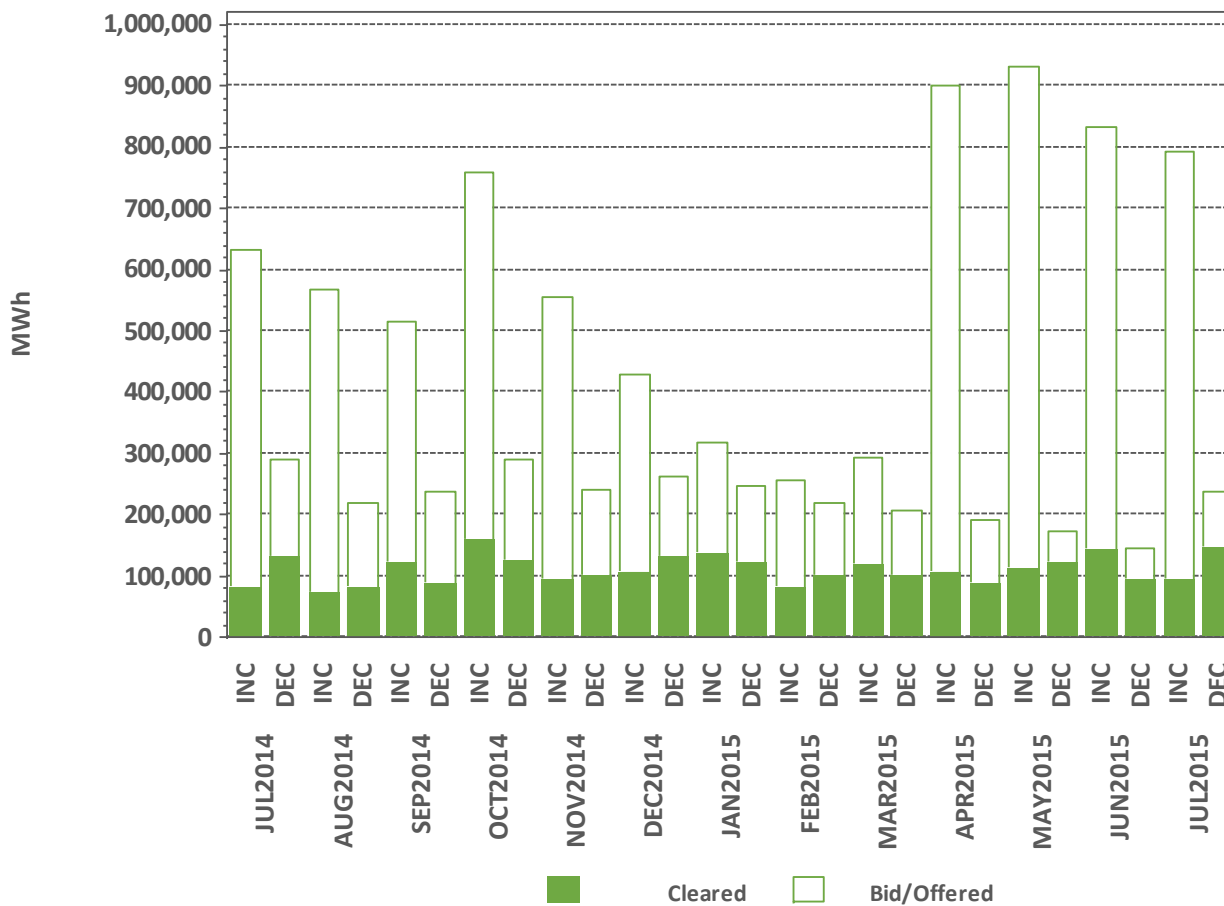
# Zonal Decrement Bids and Cleared Amounts

July Monthly Totals by Zone



# Total Increment Offers and Decrement Bids

Zonal Level, Last 13 Months

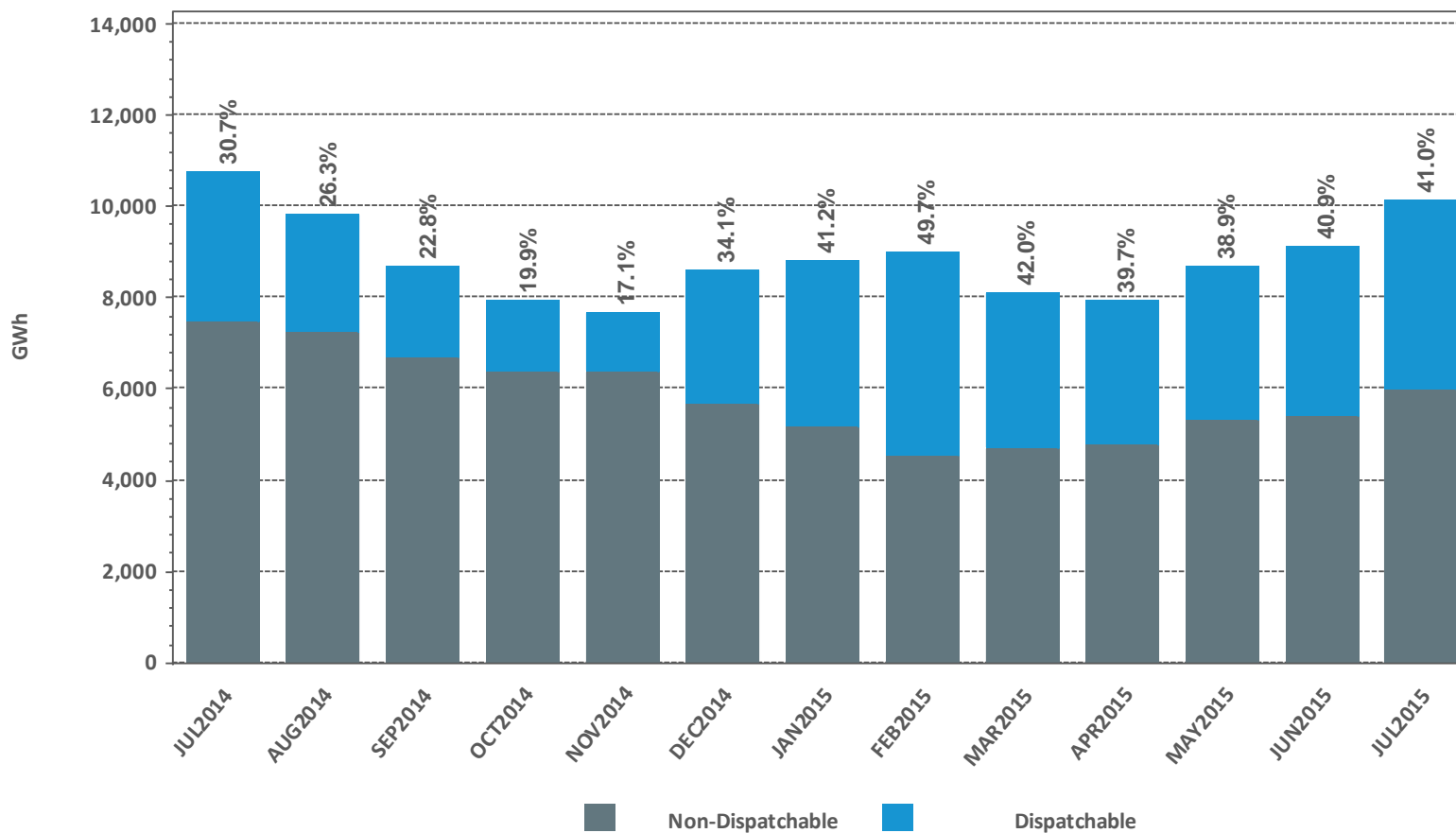


Data excludes nodal offers and bids



# Dispatchable vs. Non-Dispatchable Generation

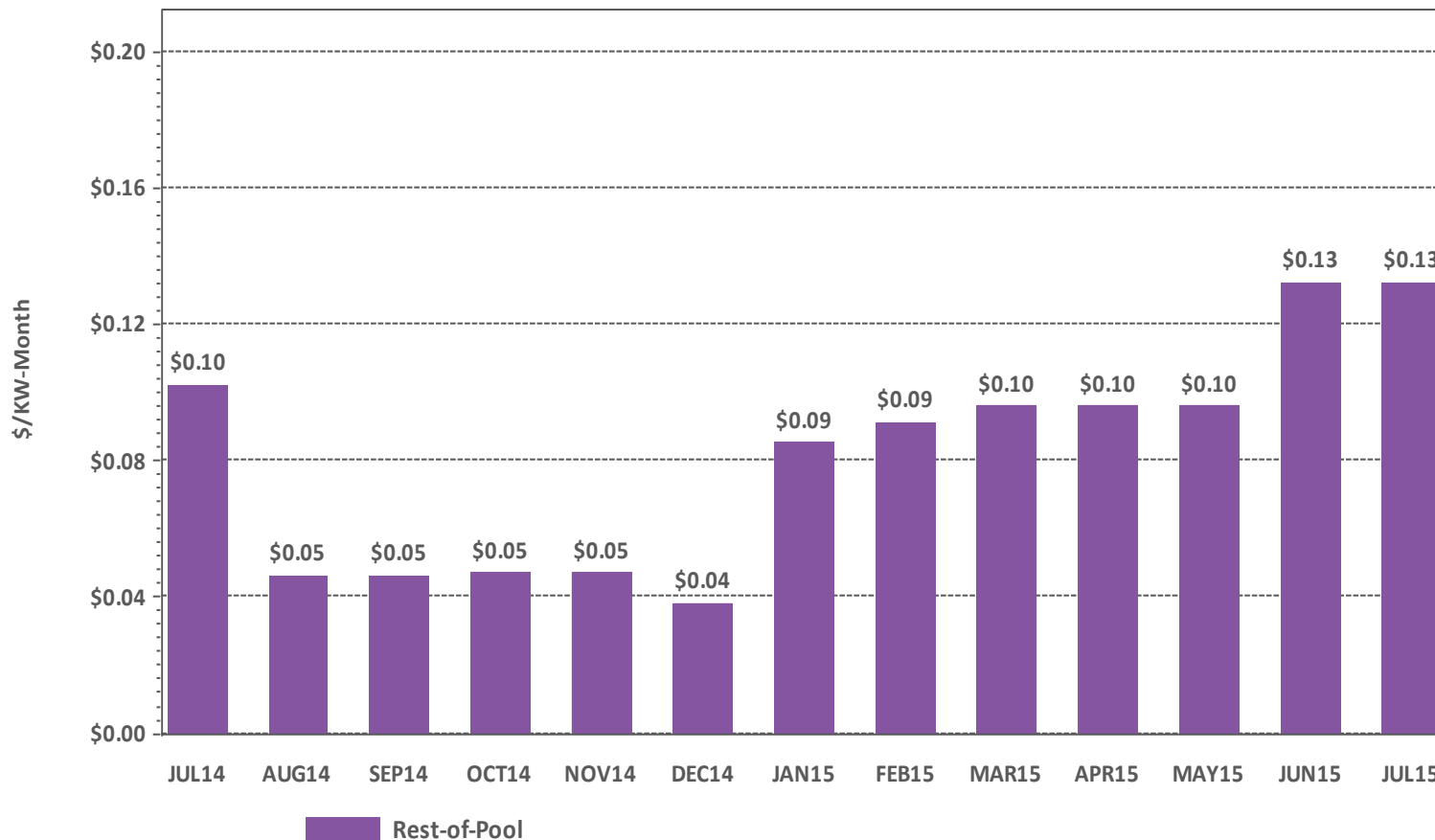
Total Monthly Energy; Dispatchable % Shown



\* Dispatchable MWh here are defined to be generation output that is not self-scheduled (i.e, not self-committed or 'must run' by the customer).



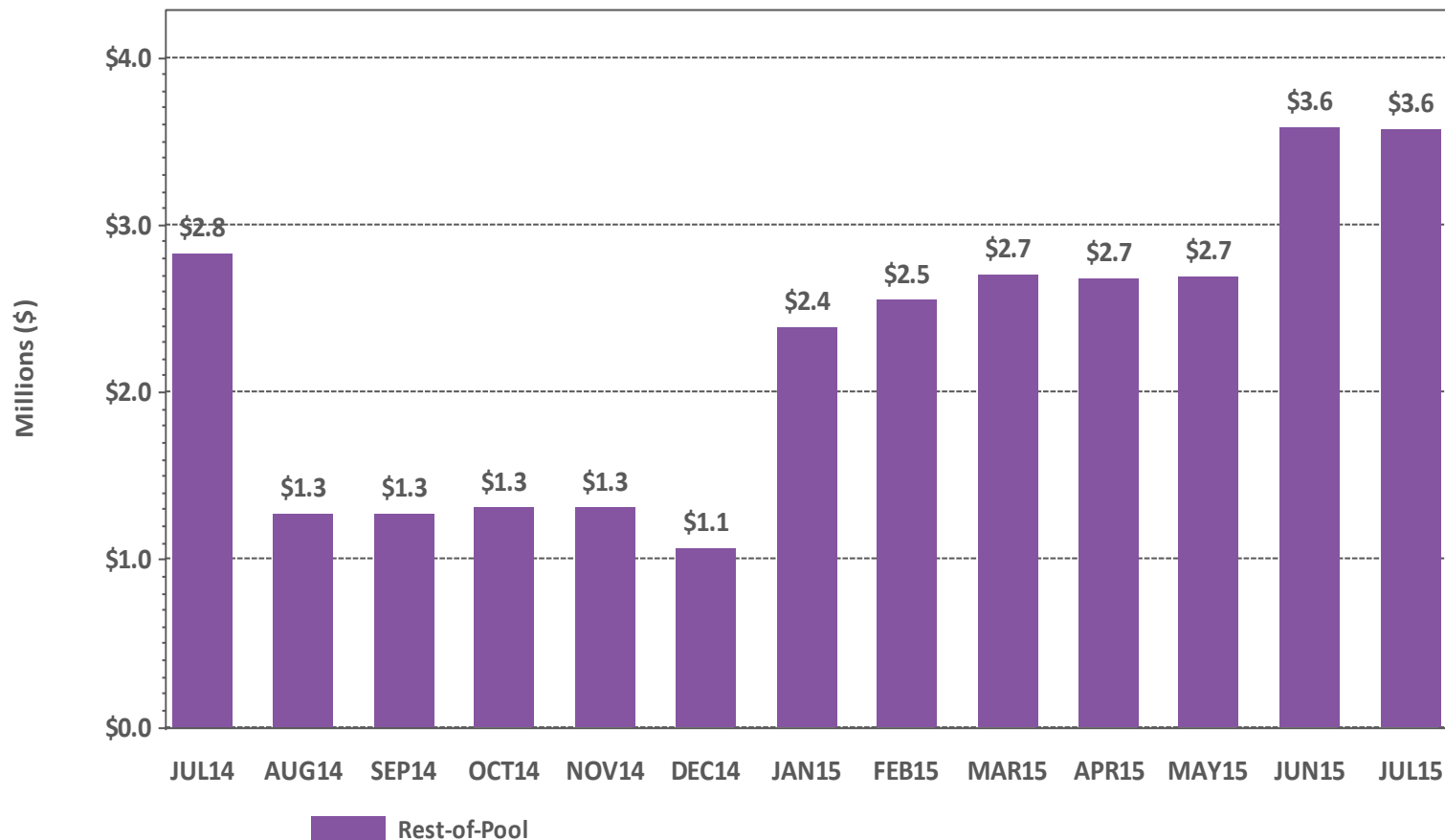
# Rolling Average Peak Energy Rent (PER)



Rolling Average PER is currently calculated as a rolling twelve month average of individual monthly PER values for the twelve months preceding the obligation month.

Individual monthly PER values are published to the ISO web site here: [Home > Markets > Other Markets Data > Forward Capacity Market > Reports](#) and are subject to resettlement.

# PER Adjustments



PER Adjustments are reductions to Forward Capacity Market monthly payments resulting from the rolling average PER.



# REGIONAL SYSTEM PLAN (RSP) AND INTERREGIONAL PLANNING



# Planning Advisory Committee (PAC)

- The draft RSP15 was posted on July 7
- The next PAC meeting is scheduled for August 6. Major agenda topics will include:
  - RSP15 Page Turn
  - Carver Street Station Needs and Solutions
- Stakeholder comments submitted to the ISO will be discussed at the August 6 meeting
- The public meeting is scheduled for Thursday, September 10, at the Seaport World Trade Center in Boston, MA from 11:00am - 4:00pm
  - Post-PAC-reviewed draft of RSP15 will be discussed
  - Panel will discuss “Public Policy and Economically Efficient Outcomes: How can the region achieve both goals?”

# Distributed Generation Forecast Working Group (DGFWG)

- ISO is working with DG resources seeking participation in the FCM
- ISO is working with the transmission owners, distribution owners, the states, and IEEE to resolve interconnection issues
- ISO will continue participation in DOE projects that support operational and planning forecasts of PV

# Environmental Matters

- Environmental Advisory Group meeting met on June 30 to discuss EPA Regulatory & Litigation Developments and a Greenhouse Gas Regulatory Update
- Environmental update also provided to July 27 PSPC meeting

# Economic Studies

- ISO is conducting three 2015 economic studies of wind integration scenarios
  - Study of the Keene Road Area
  - Study utilizing the Strategic Transmission Analysis results
  - Study of offshore wind expansion
- Studies will be given priority by the ISO and draft results to be presented to PAC by late 2015 or early 2016
  - Final reports completed after consultation with the PAC
- Studies will compare the performance of the future system with additional representative future system improvements
  - Studies will not include detailed transmission planning analysis including system impact study results
- ISO may form special economic study working groups that will supplement PAC discussions via conference calls
  - PAC presentations will be structured to discuss the general PAC economic study issues upfront
  - More technical discussions will be reviewed with PAC members as a last meeting agenda item

# 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

# NEWS: Interstate Reliability Project

*Status as of 8/3/15*

*Plan Benefit: Improves New England reliability by increasing transfer limits of three critical interfaces*

<b>Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
Build New 345 kV Line 3271 Card - Lake Road	Dec-15	3
Card 345 kV Substation Expansion	Dec-15	3
Lake Road 345 kV Substation Expansion	Dec-15	3
Build New 345 kV Line 341 Lake Road to CT/RI Border	Dec-15	3
Build New 345 kV Line 341 CT/RI Border to West Farnum	Dec-15	3
West Farnum 345 kV Substation Additions (New Line Terminations)	Dec-15	3
New Sherman Road 345 kV Substation	Dec-15	3
West Farnum 115 kV Substation Upgrades	Sep-14	4
Reconductor 345 kV Line 328 West Farnum to Sherman Road	Dec-15	3
Riverside Substation Relay Upgrades	Sep-14	4
Woonsocket Substation Relay Upgrades	Sep-14	4
Hartford Avenue Substation Relay Upgrades	Sep-14	4
Build New 345 kV Line 366 West Farnum to MA/RI Border	Dec-15	3
Build New 345 kV Line 366 MA/RI Border to Millbury 3	Dec-15	3
Millbury 3 Substation Expansion	Dec-15	3
Carpenter Hill Substation Relay Upgrades	Dec-15	3

# New Hampshire/Vermont 10-Year Upgrades

*Status as of 8/3/15*

*Project Benefit: Addresses Needs in New Hampshire and Vermont*

<b>Upgrade</b>	<b>Expected In-Service</b>	<b>Present Stage</b>
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	2
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	4
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	4
New 115 kV overhead line, Fitzwilliam-Monadnock	Dec-16	2
New 115 kV overhead line, Scobie Pond-Huse Road	Dec-15	3
New 115 kV overhead/submarine line, Madbury-Portsmouth	Dec-17	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	3
New 115 kV overhead line, Coolidge-Ascutney	Dec-16	1

Note: The above listing focuses on major transmission line construction and rebuilding.



# New Hampshire/Vermont 10-Year Upgrades, cont.

*Status as of 8/3/15*

*Project Benefit: Addresses Needs in New Hampshire and Vermont*

<b>Upgrade</b>	<b>Expected In-Service</b>	<b>Present Stage</b>
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Dec-16	3
Rebuild 115 kV line K165, W157 tap Eagle-Power Street	May-15	4
Rebuild 115 kV line H137, Merrimack-Garvins	Jun-13	4
Rebuild 115 kV line D118, Deerfield-Pine Hill	Nov-14	4
Oak Hill Substation - Loop in 115 kV line V182, Garvins-Webster	Apr-15	4*
Uprate 115 kV line G146, Garvins-Deerfield	Mar-15	4
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

\* Placed in-service ahead of schedule

Note: The above listing focuses on major transmission line construction and rebuilding.



# New Hampshire/Vermont 10-Year Upgrades, cont.

*Status as of 8/3/15*

*Project Benefit: Addresses Needs in New Hampshire and Vermont*

Upgrade	Expected In-Service	Present Stage
Upgrade 115 kV line H141, Chester-Great Bay	Nov-14	4
Upgrade 115 kV line R193, Scobie Pond-Kingston Tap	Mar-15	4*
Upgrade 115 kV line T198, Keene-Monadnock	Nov-13	4
Upgrade 345 kV line 326, Scobie Pond-NH/MA Border	Dec-13	4
Upgrade 115 kV line J114-2, Greggs - Rimmon	Dec-13	4
Upgrade 345 kV line 381, between MA/NH border and NH/VT border	Jun-13	4

\* Placed in-service ahead of schedule

Note: The above listing focuses on major transmission line construction and rebuilding.



# Greater Hartford and Central Connecticut (GHCC) Projects\*

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability*

Upgrade	Expected In-service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Dec-16	2
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Dec-17	1
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add two 115 kV 25.2 MVAR capacitor banks	Dec-17	1
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-16	2
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Dec-17	1
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Dec-17	1
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-17	1

\* Replaces the NEEWS Central Connecticut Reliability Project

# Greater Hartford and Central Connecticut (GHCC) Projects\*

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability*

Upgrade	Expected In-service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Dec-17	1
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Dec-17	1
Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-18	1
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-16	1
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	Dec-17	1
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Dec-18	1
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-18	1

\* Replaces the NEEWS Central Connecticut Reliability Project



# Greater Hartford and Central Connecticut (GHCC) Projects\*

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability*

<b>Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	1
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	1
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-18	1
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-17	1
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Dec-17	1
Add a 345 kV breaker in series with breaker 5T at Southington	Dec-17	1

\* Replaces the NEEWS Central Connecticut Reliability Project

# Greater Hartford and Central Connecticut

## Projects, cont.\*

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability*

<b>Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
Add a new control house at Southington 115 kV substation	Dec-17	1
Add a new 115 kV line from Frost Bridge to Campville	Dec-18	1
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Dec-18	1
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-17	1
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-16	2
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-16	2
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Dec-16	2

\* Replaces the NEEWS Central Connecticut Reliability Project



# Southwest Connecticut (SWCT) Projects

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability*

Upgrade	Expected In-service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Dec-17	1
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Dec-17	1
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Dec-17	1
Rebuild Bunker Hill to a 9-breaker substation in breaker-and-a-half configuration	Dec-17	1
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-17	1
Loop the 1990 line in and out the Bunker Hill substation	Dec-17	1
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Dec-17	1
Loop the 1570 line in and out the Pootatuck substation	Dec-17	1
Replace two 115 kV circuit breakers at the Freight substation	Dec-17	1



# Southwest Connecticut Projects, cont.

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability*

Upgrade	Expected In-service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	1
Add a new 115 kV line from Plumtree to Brookfield Junction	Dec-17	1
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-17	1
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Dec-17	1
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	Dec-17	1
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	Dec-17	1
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Dec-17	1
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	Dec-17	1



# Southwest Connecticut Projects, cont.

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability*

<b>Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Dec-17	1
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	Dec-17	1
Terminal equipment upgrade at the Newtown substation (1876)	Dec-17	1
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Dec-17	1
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-17	1
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-17	1



# Southwest Connecticut Projects, cont.

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability*

<b>Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Jul-16	2
Upgrade the 115 kV bus at the Baird substation	Dec-17	1
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	4
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-16	2
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Dec-18	1
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Apr-19	1



# Southwest Connecticut Projects, cont.

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability*

<b>Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
Remove the Sackett phase shifter	Dec-17	1
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-17	1
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-17	1
Separate the 3827 (Beseck to East Devon) and 1610 (Southington to June to Mix Avenue) double circuit towers	Dec-17	1
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Dec-16	1
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Dec-16	2
Replace two 115 kV circuit breakers at Mill River	Dec-14	4



# Greater Boston Projects

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability*

<b>Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
Install new 345 kV line from Scobie to Tewksbury	Dec-17	1
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Dec-17	1
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	1
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Jun-17	1
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Jun-16	1
Reconductor the F-158S 115 kV line from Maplewood to Everett	Dec-17	1
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn	Dec-18	1
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	1
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-16	1

# Greater Boston Projects, cont.

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability*

Upgrade	Expected In-service	Present Stage
Separate X-24 and E-157W DCT	Dec-15	1
Separate Q-169 and F-158N DCT	Dec-15	1
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	1
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	May-17	1
Install third 115 kV line from West Walpole to Holbrook	Dec-16	1
Install new 345 kV breaker in series with the 104 breaker at Stoughton	Dec-16	1
Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-15	3
Install a new 115 kV line from Sudbury to Hudson	Dec-18	1



# Greater Boston Projects, cont.

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability*

Upgrade	Expected In-service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-17	1
Install a 345 kV breaker in series with breaker 104 at Woburn	Dec-16	1
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	May-16	1
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Dec-15	2
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	1
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	Dec-16	1
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	Dec-16	1
Install a 115 kV breaker on the West bus at K Street	Dec-15	1
Install 115 kV cable from Mystic to Chelsea	Dec-17	1
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Dec-17	1



# Greater Boston Projects, cont.

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability*

<b>Upgrade</b>	<b>Expected In-service</b>	<b>Present Stage</b>
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-17	1
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station	Dec-16	1
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Dec-17	1
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-17	2



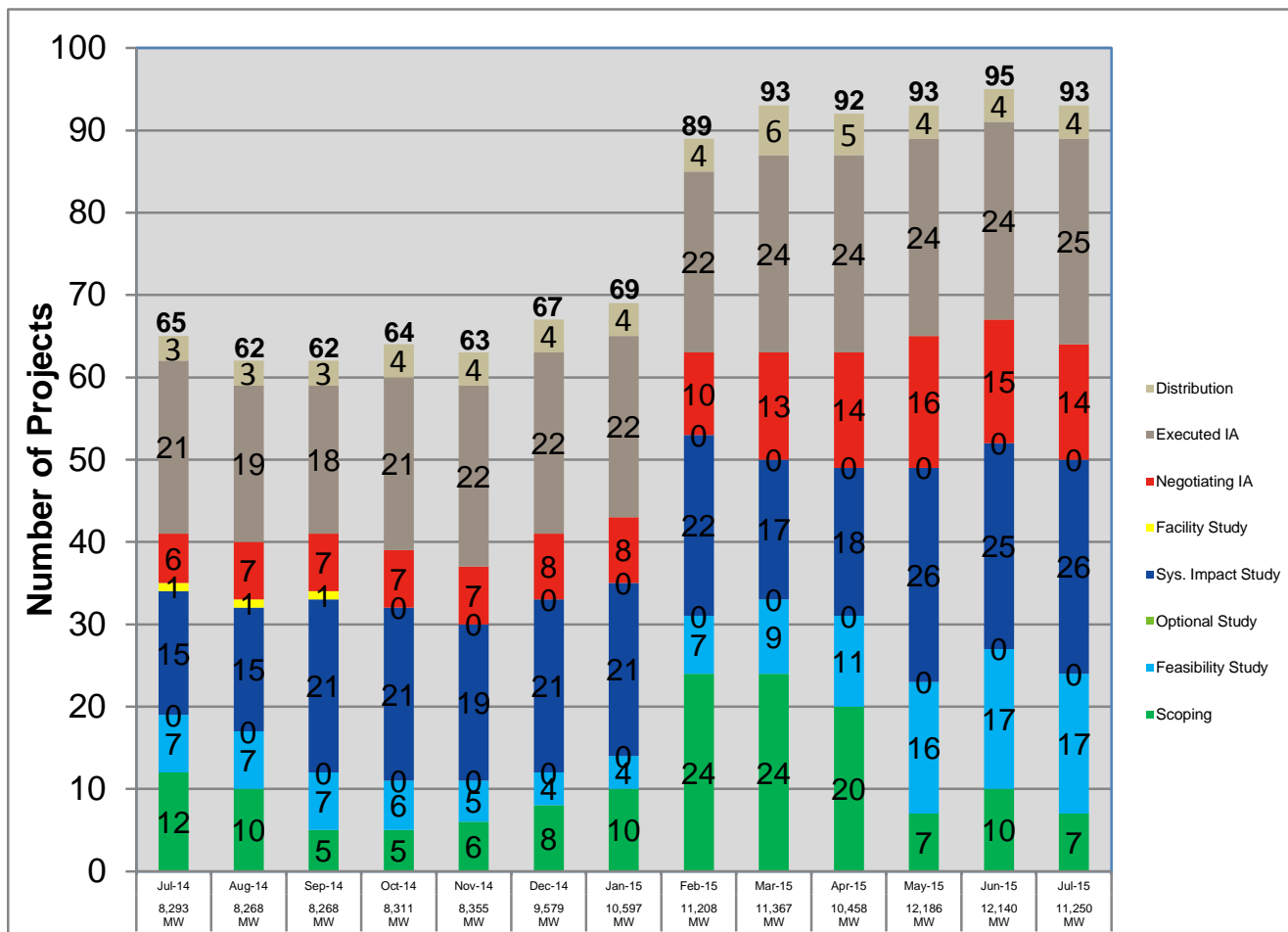
# Greater Boston Projects, cont.

*Status as of 8/3/15*

*Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability*

Upgrade	Expected In-service	Present Stage
Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Jun-16	1
Upgrade Edgar 115 kV station to BPS standards	Dec-20	1
Upgrade Dover 115 kV station to BPS standards	Dec-20	1
Upgrade East Cambridge 115 kV station to BPS standards	Dec-19	1
Upgrade West Methuen 115 kV station to BPS standards	Jun-18	1
Upgrade Medway 115 kV station to BPS standards	Dec-19	1
Install a 200 MVAR STATCOM at Coopers Mills	TBD	1
Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	1
Install a 345 kV 160 MVAR shunt reactor at K Street	May-18	1
Install a 115 kV breaker in series with the 5 breaker at Framingham	Jun-17	1
Install a 115 kV breaker in series with the 29 breaker at K Street	Dec-15	1

# Status of Tariff Studies



Generator Project Status

<https://irtt.iso-ne.com/external.aspx>

Note: As of July 2015, there are 8 ETU's in SIS

# OPERABLE CAPACITY ANALYSIS

*Summer 2015*



# Summer 2015 Operable Capacity Analysis

<b>50/50 Load Forecast (Reference)</b>	<b>September - 2015<sup>2</sup> CSO</b>	<b>September - 2015<sup>2</sup> SCC</b>
Generator Operable Capacity MW <sup>1</sup>	29,569	30,295
OP CAP From OP-4 RTDR (+)	444	444
OP CAP From OP-4 RTEG (+)	192	192
Operable Capacity Generator with OP-4 DR and RTEG	30,205	30,931
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,237	1,237
Non Commercial Capacity (+)	6	6
Non Gas-fired Planned Outage MW (-)	45	45
Gas Generator Outages MW (-)	565	613
Allowance for Unplanned Outages (-) <sup>5</sup>	2,100	2,100
Generation at Risk Due to Gas Supply (-) <sup>4</sup>	0	0
Net Capacity (NET OPCAP SUPPLY MW) <sup>3</sup>	28,738	29,416
Peak Load Forecast MW (adjusted for Other Demand Resources) <sup>2</sup>	26,710	26,710
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	29,085	29,085
Operable Capacity Margin <sup>3</sup>	(347)	331

<sup>1</sup> Generator Operable Capacity is based on data as of **July 6, 2015** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

<sup>2</sup> Load based on 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **September 5, 2015**.

<sup>3</sup> Includes OP4 actions associated with RTEG and RTDR

<sup>4</sup> Total of (Gas at Risk MW) – (Gas Gen Outages MW)

<sup>5</sup> Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

# Summer 2015 Operable Capacity Analysis

<b>90/10 Load Forecast (Extreme)</b>	<b>September - 2015<sup>2</sup> CSO</b>	<b>September - 2015<sup>2</sup> SCC</b>
Generator Operable Capacity MW <sup>1</sup>	29,569	30,295
OP CAP From OP-4 RTDR (+)	444	444
OP CAP From OP-4 RTEG (+)	192	192
Operable Capacity Generator with OP-4 DR and RTEG	30,205	30,931
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,237	1,237
Non Commercial Capacity (+)	6	6
Non Gas-fired Planned Outage MW (-)	45	45
Gas Generator Outages MW (-)	565	613
Allowance for Unplanned Outages (-) <sup>5</sup>	2,100	2,100
Generation at Risk Due to Gas Supply (-) <sup>4</sup>	0	0
Net Capacity (NET OPCAP SUPPLY MW) <sup>3</sup>	28,738	29,416
Peak Load Forecast MW (adjusted for Other Demand Resources) <sup>2</sup>	29,060	29,060
Operating Reserve Requirement MW	2,375	2,375
Operable Capacity Required (NET LOAD OBLIGATION MW)	31,435	31,435
Operable Capacity Margin <sup>3</sup>	(2,697)	(2,019)

<sup>1</sup> Generator Operable Capacity is based on data as of **July 6, 2015** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity.

<sup>2</sup> Load based on 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **September 5, 2015**.

<sup>3</sup> Includes OP4 actions associated with RTEG and RTDR

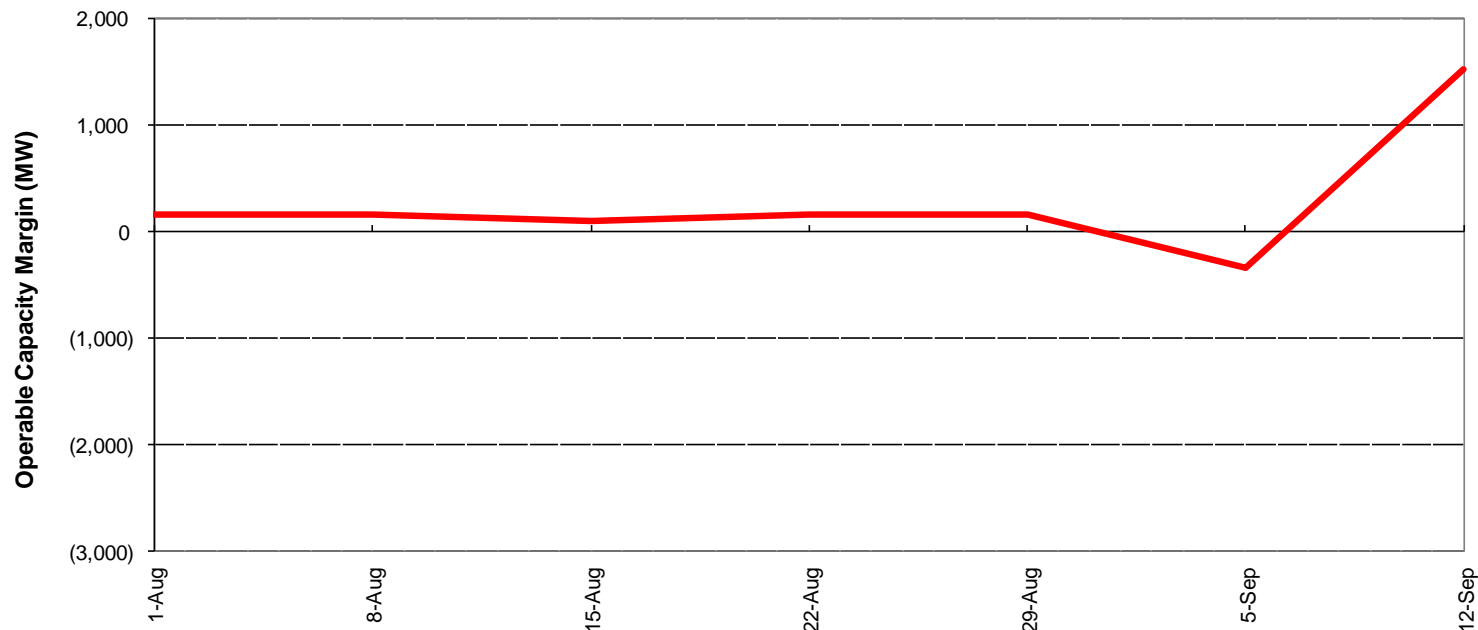
<sup>4</sup> Total of (Gas at Risk MW) – (Gas Gen Outages MW)

<sup>5</sup> Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

# Summer 2015 Operable Capacity Analysis (MW)

## 50/50 Forecast (Reference)

ISO-NE 2015 OPERABLE CAPACITY ANALYSIS - CSO - with RTDR and RTEG  
- 50/50 FORECAST

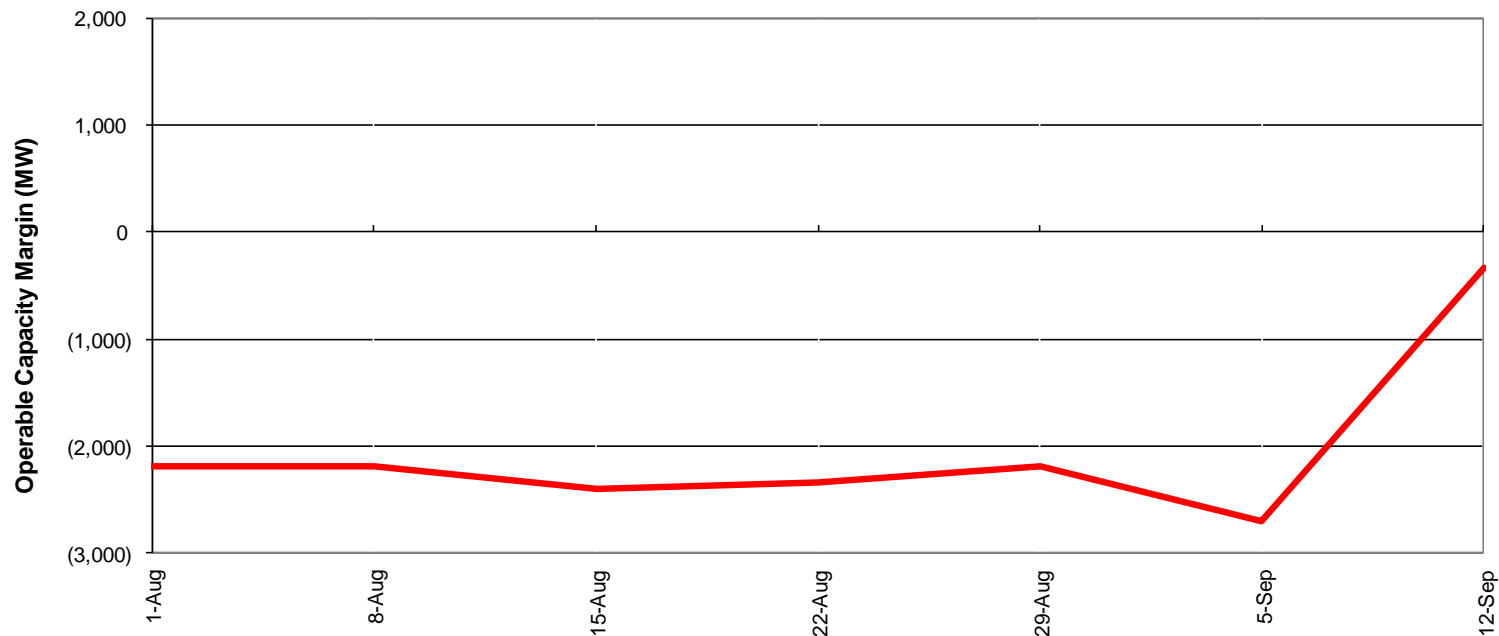


August 1, 2015 - September 12, 2015, W/B Saturday

# Summer 2015 Operable Capacity Analysis (MW)

## 90/10 Forecast (Extreme)

ISO-NE 2015 OPERABLE CAPACITY ANALYSIS - CSO - with RTDR and RTEG  
- 90/10 FORECAST



August 1, 2015 - September 12, 2015, W/B Saturday

# Summer 2015 Operable Capacity Analysis (MW)

## 50/50 Forecast (Reference)

### ISO-NE 2015 OPERABLE CAPACITY ANALYSIS

August 7, 2015 - 50/50 FORECAST using CSO values with RTDR and RTEG

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 and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERAT OR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK 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]	[16]	
8/1/2015	29,825	1,082	0	29	72	2,100	0	28,706	26,710	2,375	29,085	(379)	347	(32)	185	153
8/8/2015	29,825	1,082	0	29	72	2,100	0	28,706	26,710	2,375	29,085	(379)	347	(32)	185	153
8/15/2015	29,825	1,082	0	85	72	2,100	0	28,650	26,710	2,375	29,085	(435)	347	(88)	185	97
8/22/2015	29,825	1,082	0	29	72	2,100	0	28,706	26,710	2,375	29,085	(379)	347	(32)	185	153
8/29/2015	29,569	1,237	6	38	72	2,100	0	28,602	26,710	2,375	29,085	(483)	444	(39)	192	153
9/5/2015	29,569	1,237	6	45	565	2,100	0	28,102	26,710	2,375	29,085	(983)	444	(539)	192	(347)
9/12/2015	29,569	1,237	6	1,574	874	2,100	0	26,264	23,016	2,375	25,391	873	444	1,317	192	1,509

- Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
- External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
- New resources and generator improvements that have acquired a CSO but have not become commercial.
- Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
- All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
- Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
- Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
- Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
- Peak Load Forecast as provided in the 2015 CELT Report and adjusted for Passive Demand Resources. <http://www.iso-ne.com/system-planning/system-plans-studies/celt>
- Operating Reserve Requirement based on 125% of first largest contingency plus 50% of the second largest contingency.
- Total Net Load Obligation per the formula(9 + 10 = 11)
- Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
- OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
- OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
- OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
- OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)  
This does not include Emergency Energy Transactions (EETs).

# Summer 2015 Operable Capacity Analysis (MW)

## 90/10 Forecast (Extreme)

### ISO-NE 2015 OPERABLE CAPACITY ANALYSIS

August 7, 2015 - 90/10 FORECAST using CSO values with RTDR and RTEG

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 and Mid September.

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERAT OR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK 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]	[16]	
8/1/2015	29,825	1,082	0	29	72	2,100	0	28,706	29,060	2,375	31,435	(2,729)	347	(2,382)	185	(2,197)
8/8/2015	29,825	1,082	0	29	72	2,100	0	28,706	29,060	2,375	31,435	(2,729)	347	(2,382)	185	(2,197)
8/15/2015	29,569	1,082	0	85	72	2,100	0	28,394	29,060	2,375	31,435	(3,041)	444	(2,597)	192	(2,405)
8/22/2015	29,569	1,082	0	29	72	2,100	0	28,450	29,060	2,375	31,435	(2,985)	444	(2,541)	192	(2,349)
8/29/2015	29,569	1,237	6	38	72	2,100	0	28,602	29,060	2,375	31,435	(2,833)	444	(2,389)	192	(2,197)
9/5/2015	29,569	1,237	6	45	565	2,100	0	28,102	29,060	2,375	31,435	(3,333)	444	(2,889)	192	(2,697)
9/12/2015	29,769	1,237	6	1,574	874	2,100	0	26,464	25,060	2,375	27,435	(971)	444	(527)	192	(335)

- Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
- External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
- New resources that have acquired a CSO but have not become commercial.
- Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.
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- Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
- Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
- Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
- Peak Load Forecast as provided in the 2015 CELT Report and adjusted for Passive Demand Resources. <http://www.iso-ne.com/systemplanning/systemplansstudies/celt>
- Operating Reserve Requirement based on 125% of first largest contingency plus 50% the second largest contingency.
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- Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
- OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
- OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
- OP 4 Action 6 Emergency Generation Response without the Voltage Reduction requiring > 10 Minutes based on OP4 Appendix A. Real Time Emergency Generation is capped at 600MW. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
- OPCAP Margin taking into account Real Time Demand Response and Real Time Emergency Generation through OP4 Step 6 (14 + 15 = 16)  
This does not include Emergency Energy Transactions (EETs).

# OPERABLE CAPACITY ANALYSIS

## *Appendix*



# 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 advise Resources with a CSO to 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 <sup>1</sup>  600
2	Dispatch real time Demand Resources.	<b>August 347<sup>3</sup></b> <b>September-November 444<sup>3</sup></b>
3	Voluntary Load Curtailment of Market Participants’ facilities.	40 <sup>2</sup>
4	Implement Power Watch	0
5	Schedule Emergency Energy Transactions and arrange to purchase Control Area-to-Control Area Emergency	1,000
6	Voltage Reduction requiring > 10 minutes  Dispatch real time Emergency Generation	135 <sup>4</sup>  <b>August 185<sup>3</sup></b> <b>September –November 192<sup>3</sup></b>

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 RTDR and RTEG MW values are based on FCM results as of July 6, 2015.
4. The MW values are based on a 26,930 MW system load and the most recent voltage reduction test % achieved.



# 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)
7	Request generating resources not subject to a Capacity Supply Obligation to voluntarily provide energy for reliability purposes	0
8	Voltage Reduction requiring 10 minutes or less	269 <sup>4</sup>
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency.	5
	Voluntary Load Curtailment by Large Industrial and Commercial Customers.	200 <sup>2</sup>
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 <sup>2</sup>
11	Request State Governors to Reinforce Power Warning Appeals.	100 <sup>2</sup>
Total		<b>August 3,081 MW September-November 3,185 MW</b>

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 RTDR and RTEG MW values are based on FCM results as of July 6, 2015.
4. The MW values are based on a 26,930 MW system load and the most recent voltage reduction test % achieved.





# NEPOOL Participants Committee Report

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*June 2015 Markets & Operations Data – Not  
a Full Report*

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER



# Table of Contents

• Highlights	Page	3
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• Back-Up Detail	Page	25
– Load Response	Page	26
– Reliability Costs - Net Commitment Period Compensation (NCPC) Operating Costs	Page	28



# Highlights

- Average natural gas prices ( $\$ < 1.90$ /MMBtu), DA LMPs ( $\$21.16$ /MWh), RT LMPs ( $\$19.61$ /MWh) all were the lowest since SMD
- June Energy Market Value was ( $\$246$ M), the lowest since SMD

Underlying natural gas data furnished by:



## Highlights, cont.

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy Market Value was \$246M over the period, down \$29M from May 2015 and down \$186M from June 2014
  - June natural gas prices over the period were 11.6% lower than May 2015 average values
  - Average RT Hub Locational Marginal Prices (LMPs) over the period were 25% lower than May 2015 averages
  - Average June 2015 natural gas prices and RT Hub LMPs over the period were down 57% and 48%, respectively, from June 2014 averages
- Average DA cleared physical energy in the peak hours as percent of forecasted load was 97.9% during June, down from 98.7% during May

\*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

Underlying natural gas data furnished by:



## Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - June NCPC payments totaled \$9.4M, up \$3.1M from May and up \$3.5M from June 2014
  - First Contingency payments totaled \$4.7M, up \$312K from May
    - \$4.4M paid to internal resources, up \$145K from May
      - \$466K charged to DALO, \$4.0M to RT Deviations
    - \$219K paid to resources at external locations, up \$168K from May
  - Second Contingency payments totaled \$4.6M, up \$2.6M from the May total of \$2.0M
    - Driven by NEMA reliability commitments
    - A reallocation of \$1.8M of these charges to NEMA network load is scheduled
  - Voltage payments were \$193K, up \$193K from May
  - NCPC payments over the period as percent of Energy Market value were 3.8%

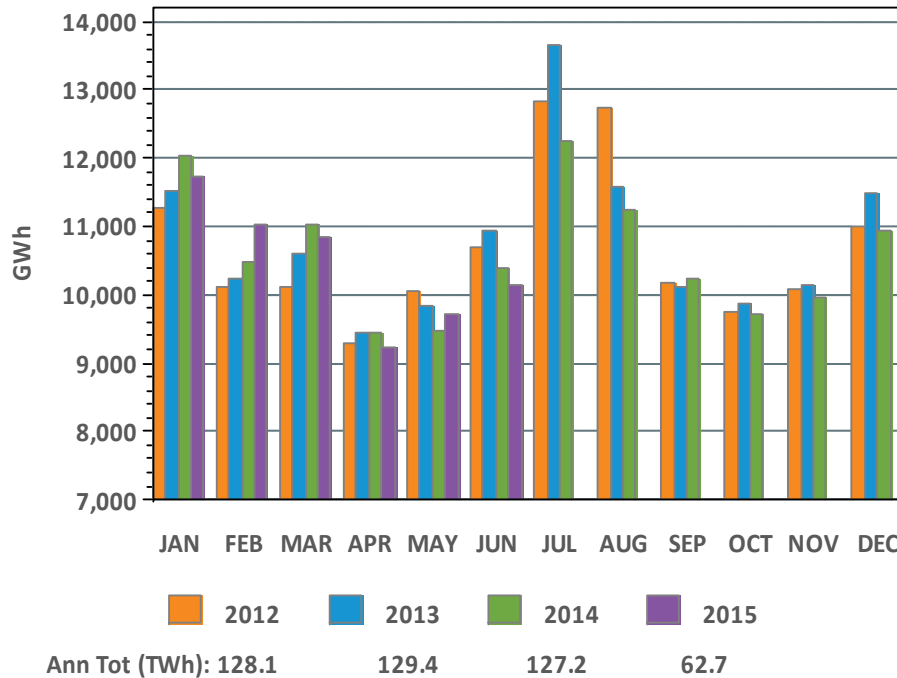


# SYSTEM OPERATIONS

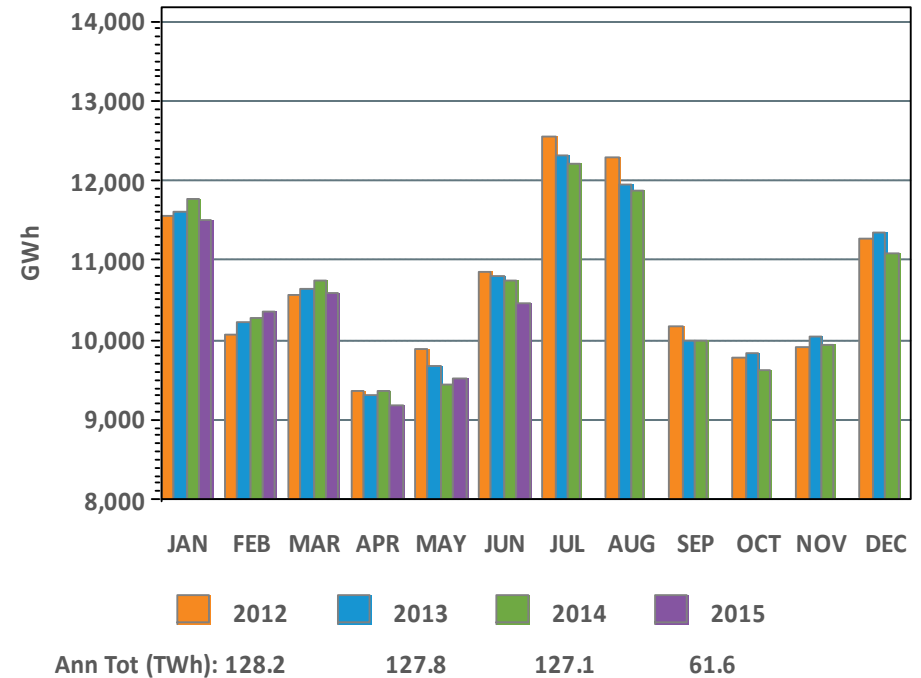


# Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

Net Energy for Load (NEL)



Weather Normalized NEL

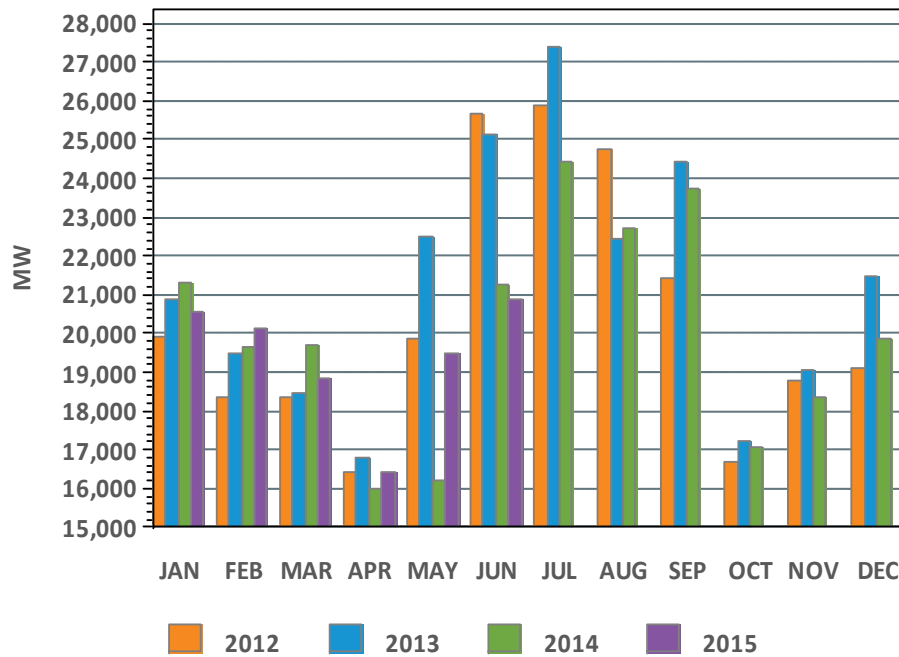


NEPOOL NEL is the total net energy required to serve load and is analogous to 'RT system load'. NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed.  
 Current month's data may be preliminary. Weather normalized NEL may be reported on a one-month lag.

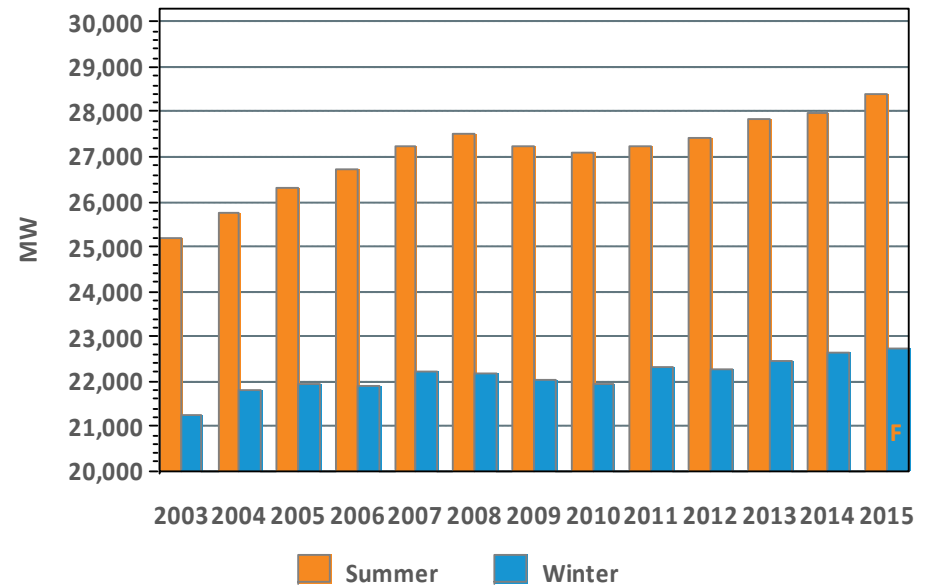


# Monthly Peak Loads and Weather Normalized Seasonal Peak History

System Peak Load



Weather Normalized Seasonal Peaks



Winter beginning in year displayed

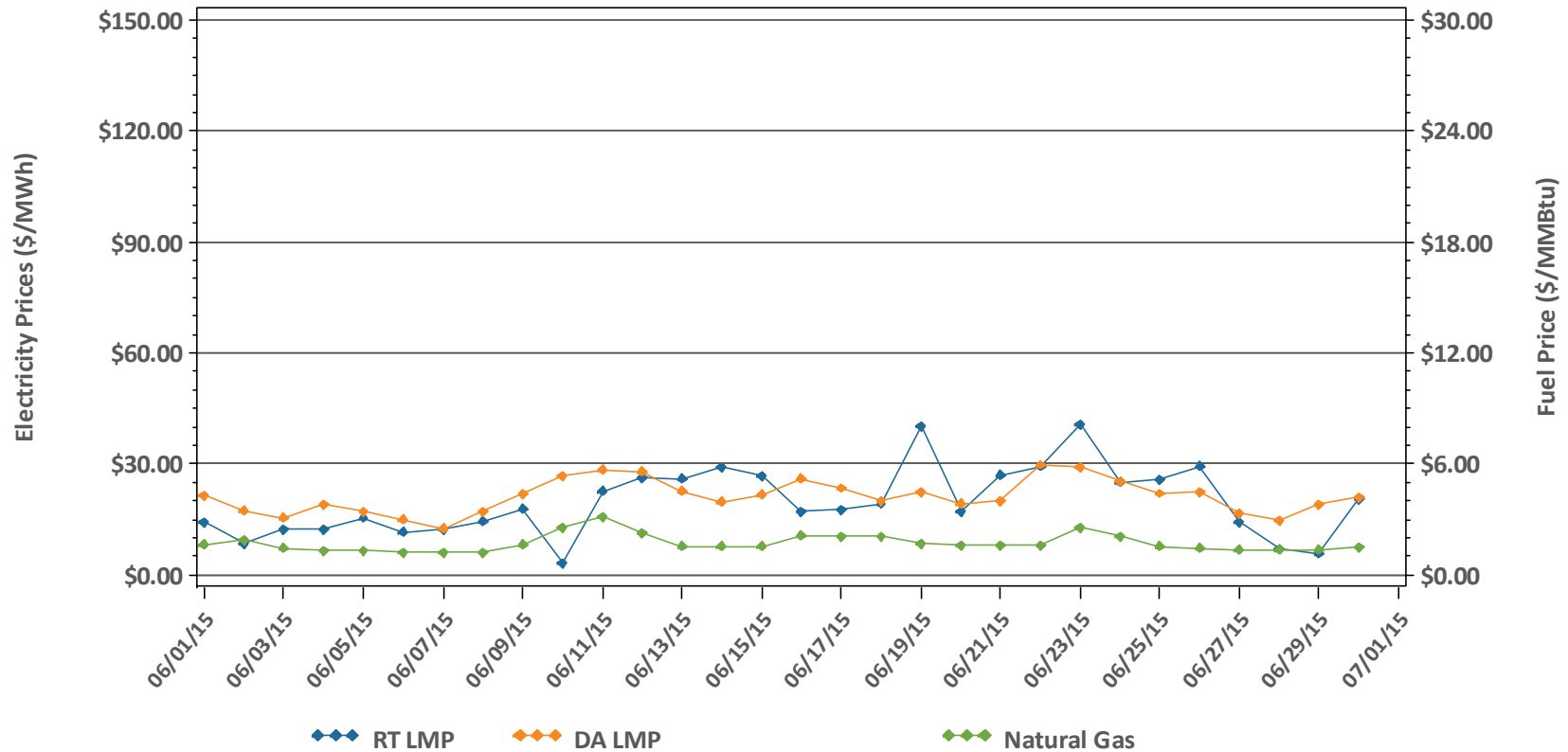
F – designates forecasted values, which are updated in April/May of the following year; represents “gross forecast”



# MARKET OPERATIONS



# Daily DA and RT ISO-NE Hub Prices and Input Fuel Prices: June 1-30, 2015



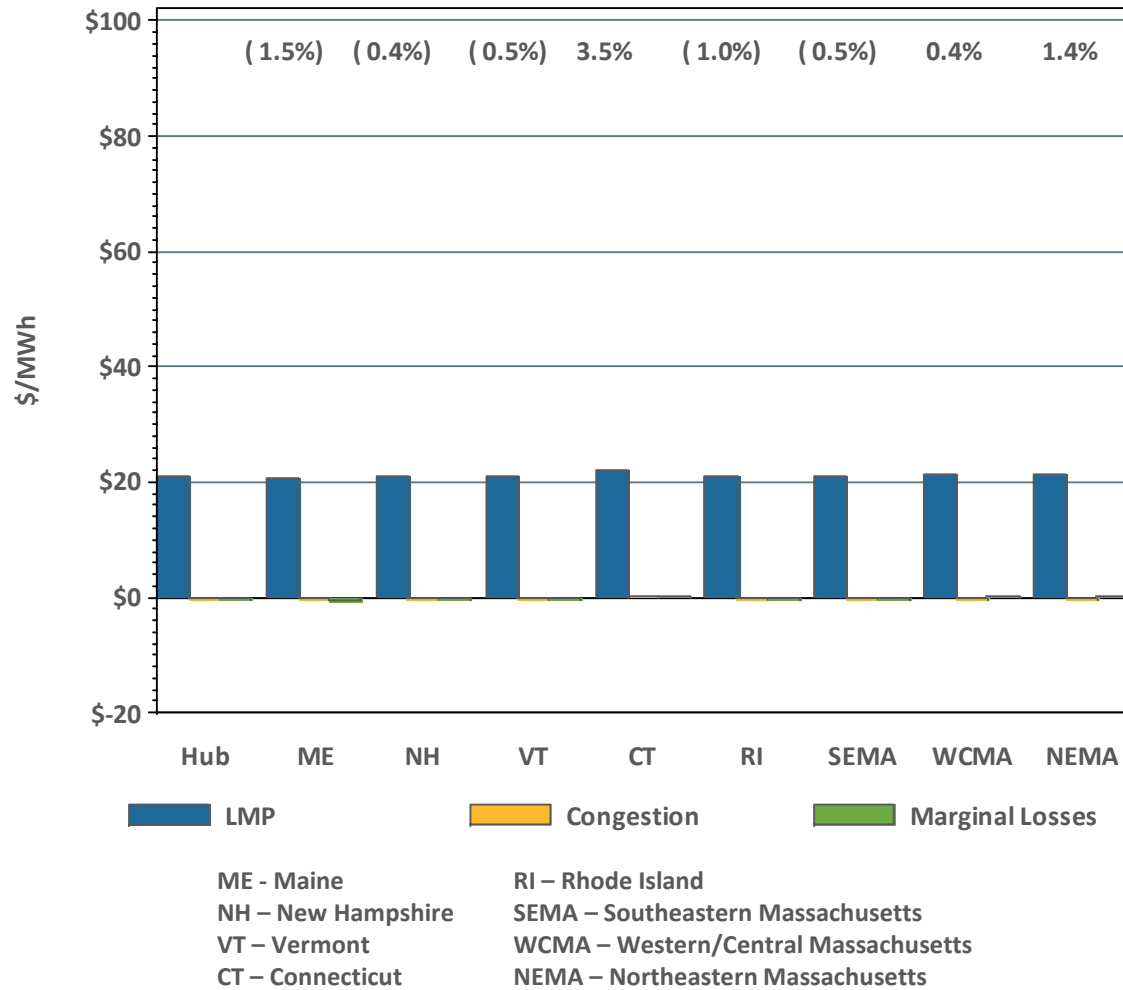
Underlying natural gas data furnished by:



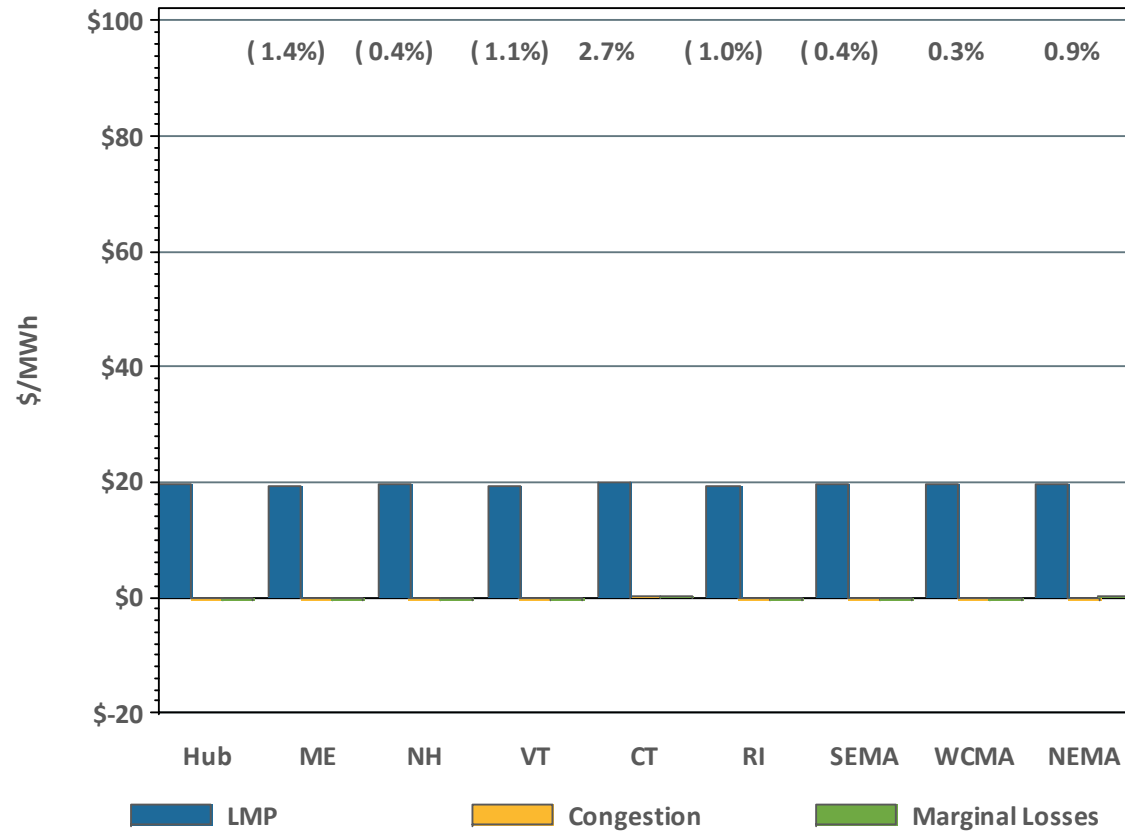
Average price difference over this period (DA-RT): \$1.55  
 Average price difference over this period ABS(DA-RT): \$5.84  
 Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 30%  
 Gas price is average of Massachusetts delivery points



# DA LMPs Average by Zone & Hub, June 2015



# RT LMPs Average by Zone & Hub, June 2015

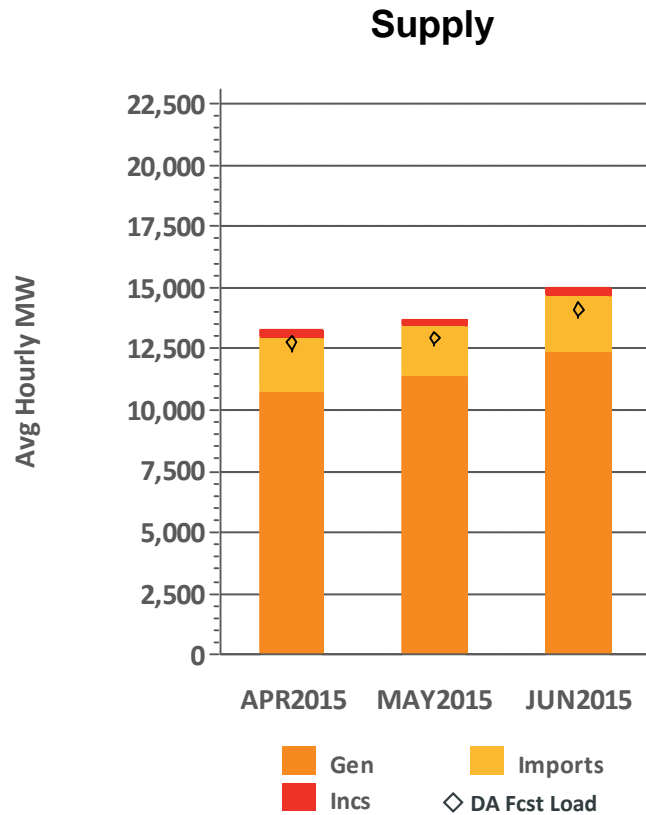


# Definitions

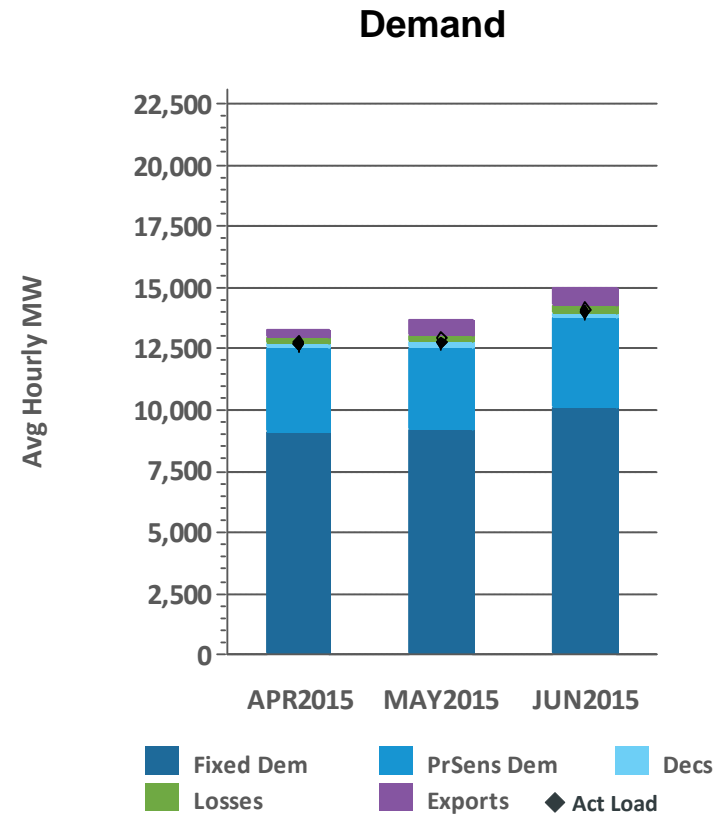
Day-Ahead Concept	Definition
Day-Ahead Load Obligation ( <b>DALO</b> )	The sum of day-ahead cleared load (including pump load), exports, and virtual purchases (excluding bulk losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports



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



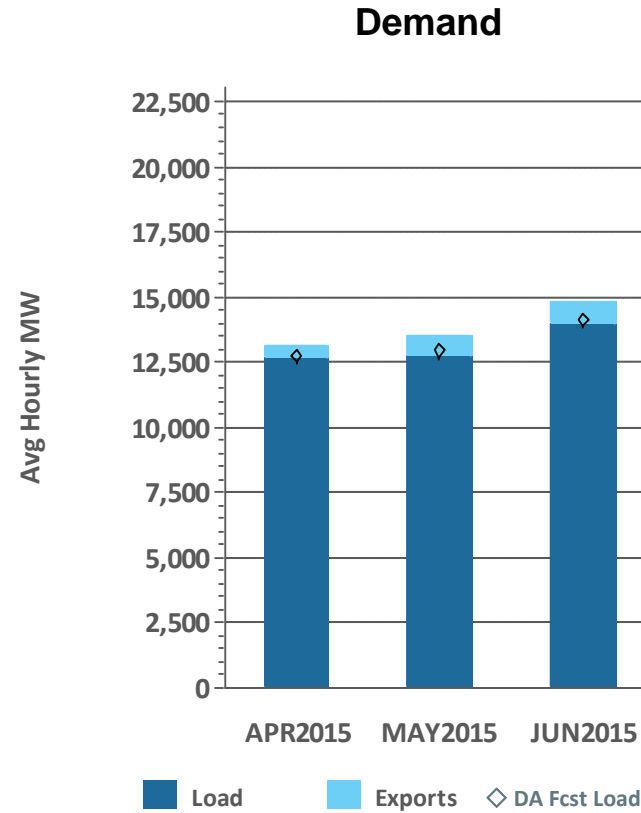
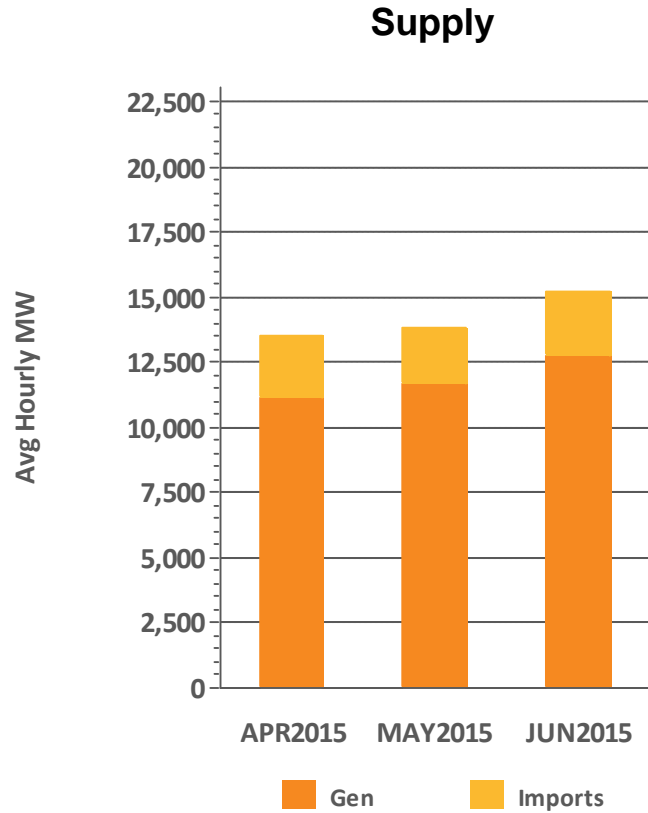
Gen – Generation  
 Incs – Increment Offers  
 DA Fcst Load – Day-Ahead Forecast Load



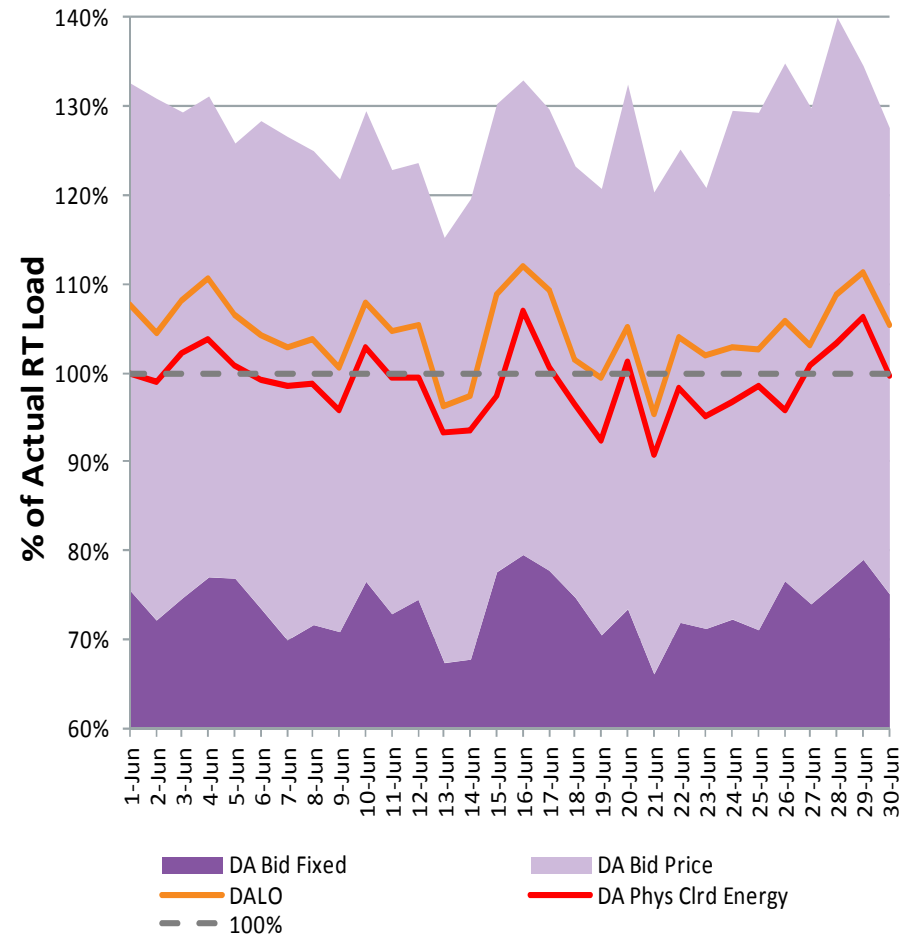
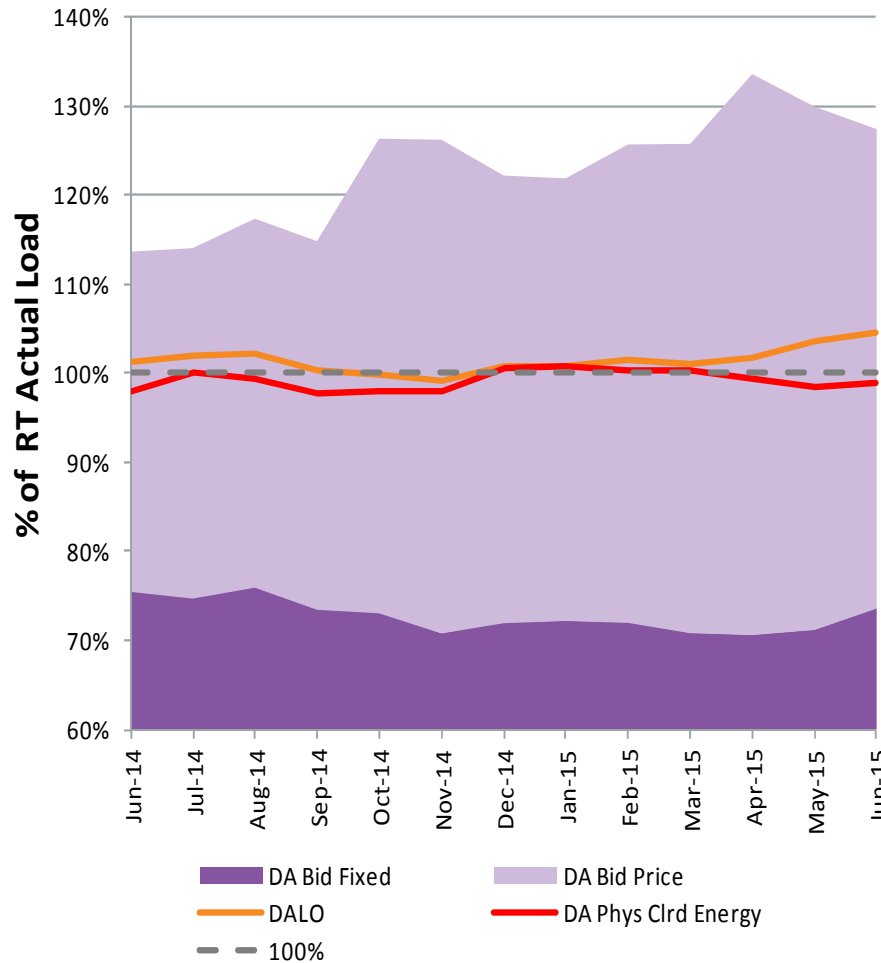
Fixed Dem – Fixed Demand  
 PrSens Dem – Price Sensitive Demand  
 Decs – Decrement Bids  
 Act Load – Actual Load



# Components of RT Supply and Demand – Last Three Months



# DAM Volumes vs. RT Actual Load (Peak Hour): Monthly and Daily

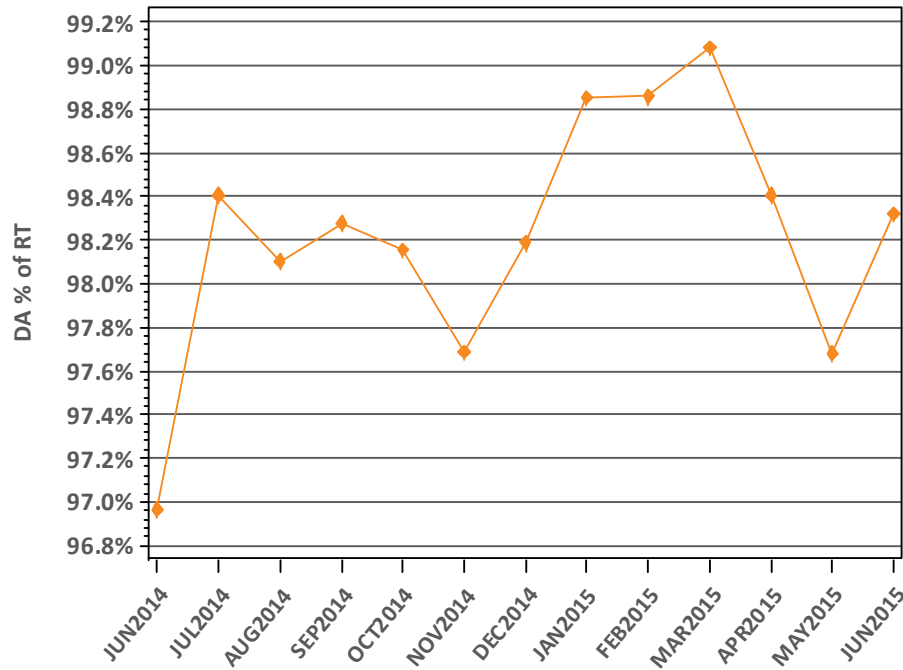


Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load.

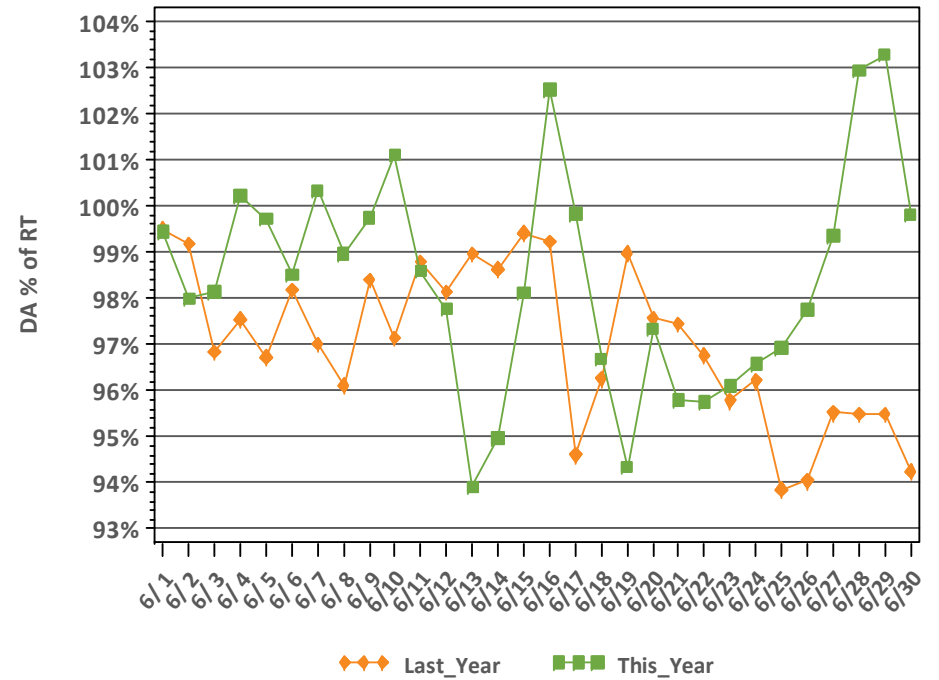


# DA vs. RT Load Obligation: June, This Year vs. Last Year

Monthly, Last 13 Months



Daily, This Year vs. Last Year

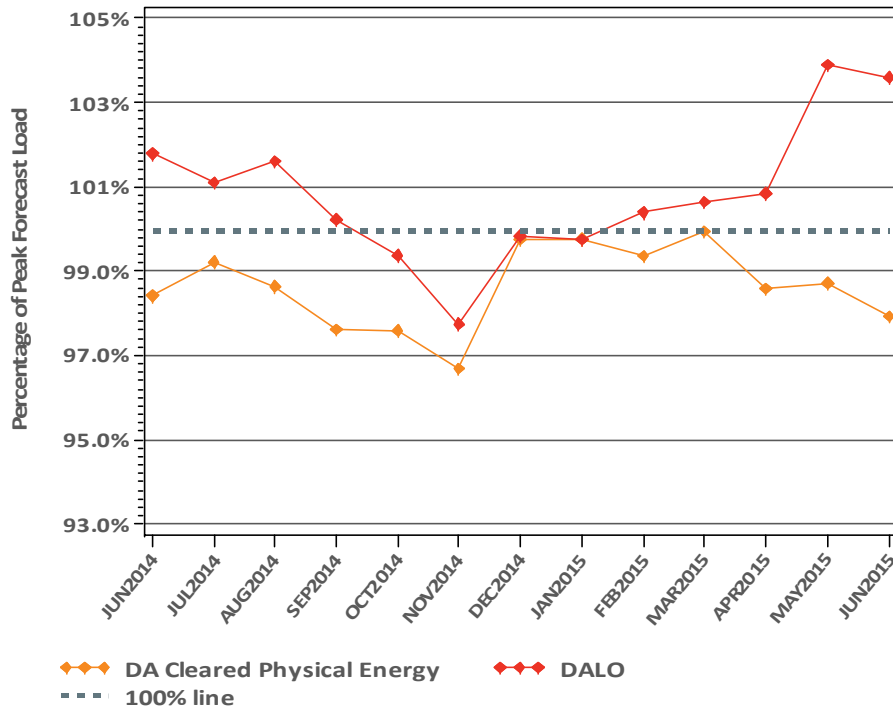


\*Hourly average values

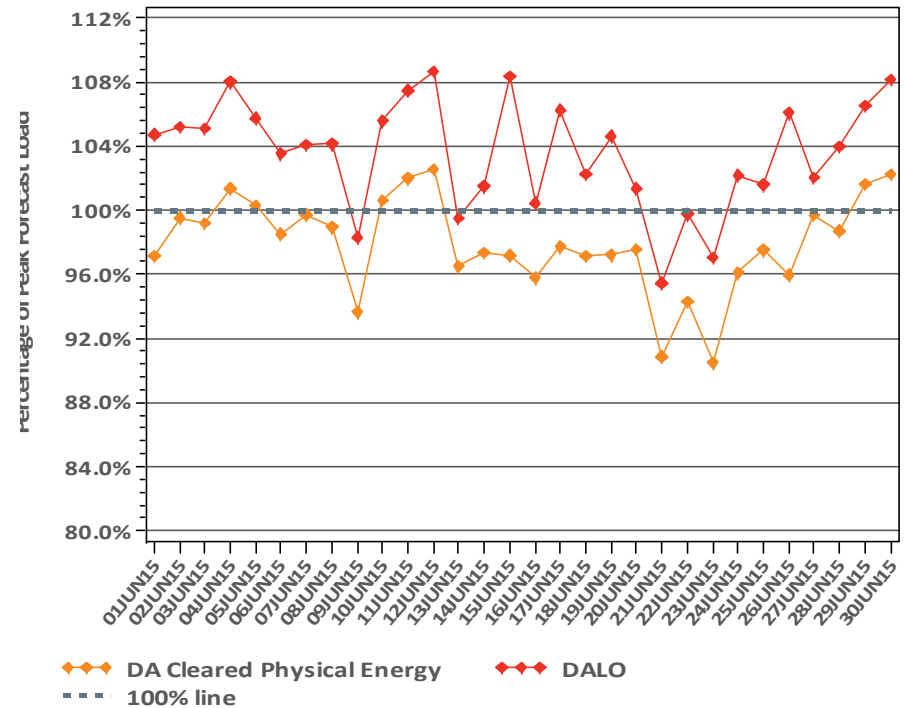


# DA Volumes as % of Forecast (Peak Hour)

Monthly, Last 13 Months



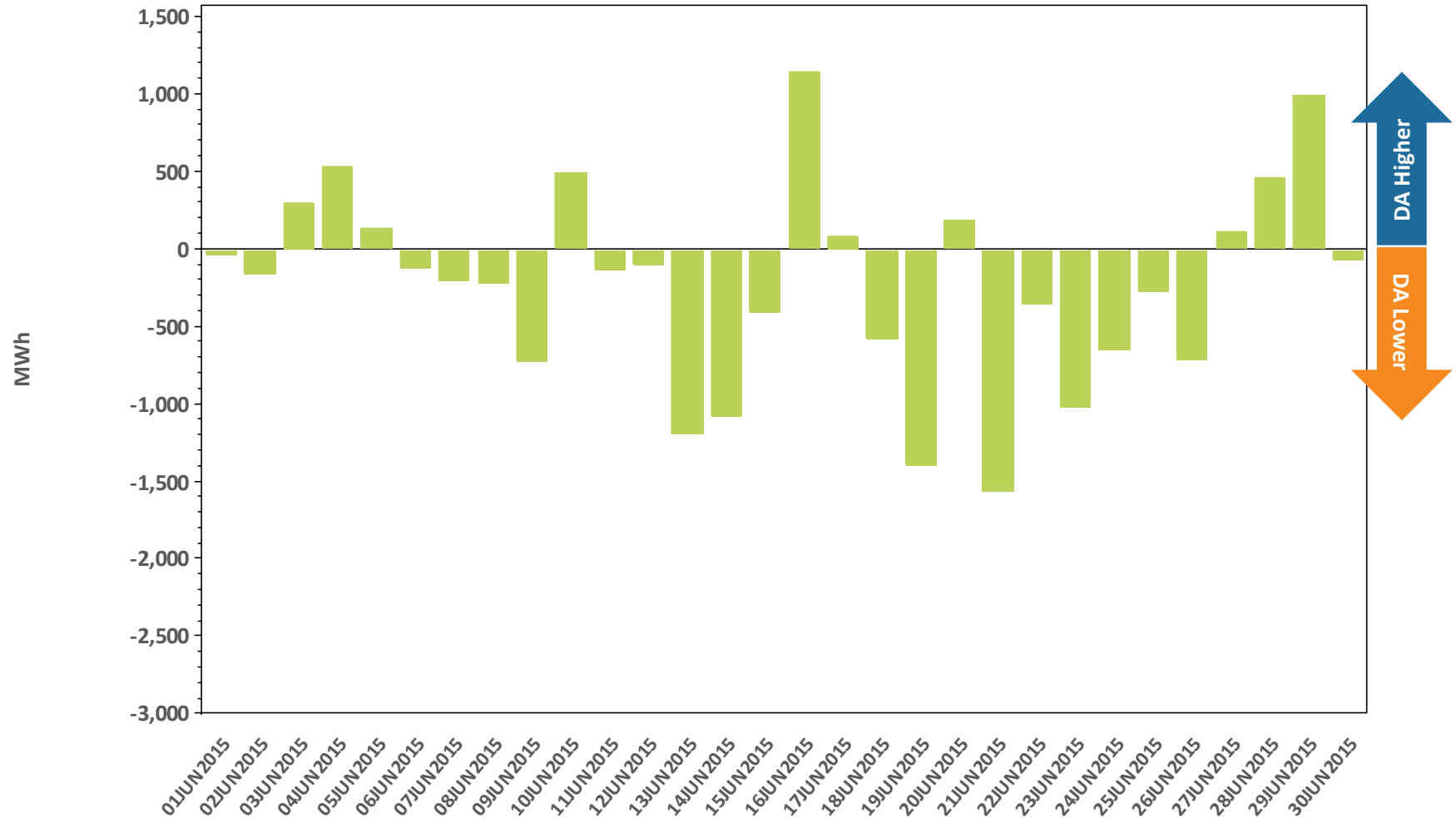
Daily: This Month



\*Forecasted peak hour is reflected.



# DA Cleared Physical Energy Difference from RT System Load at Peak Hour

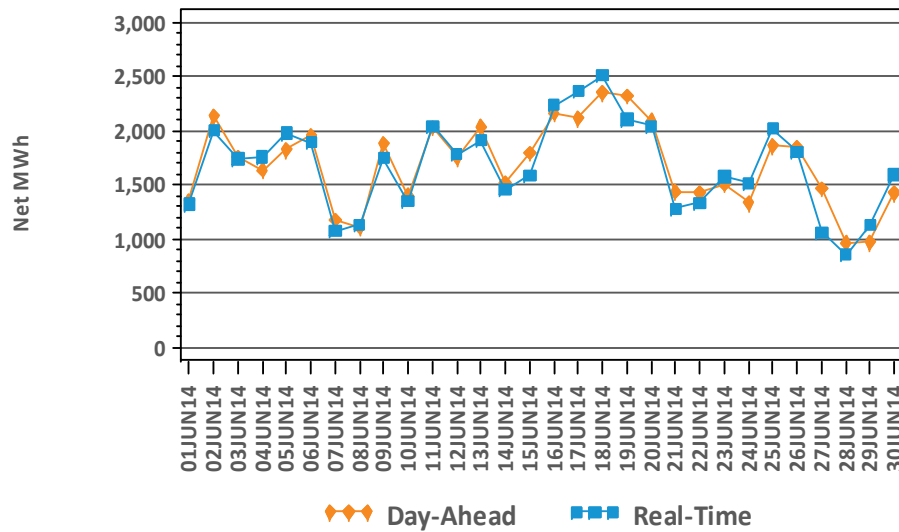


\*Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.

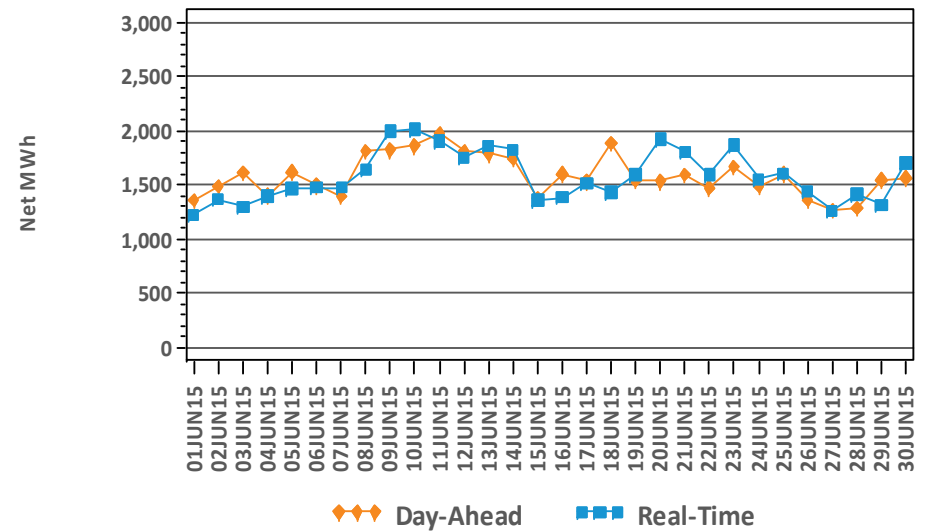


# DA vs. RT Net Interchange June 2015 vs. June 2014

Hourly Average by Day, Last Year



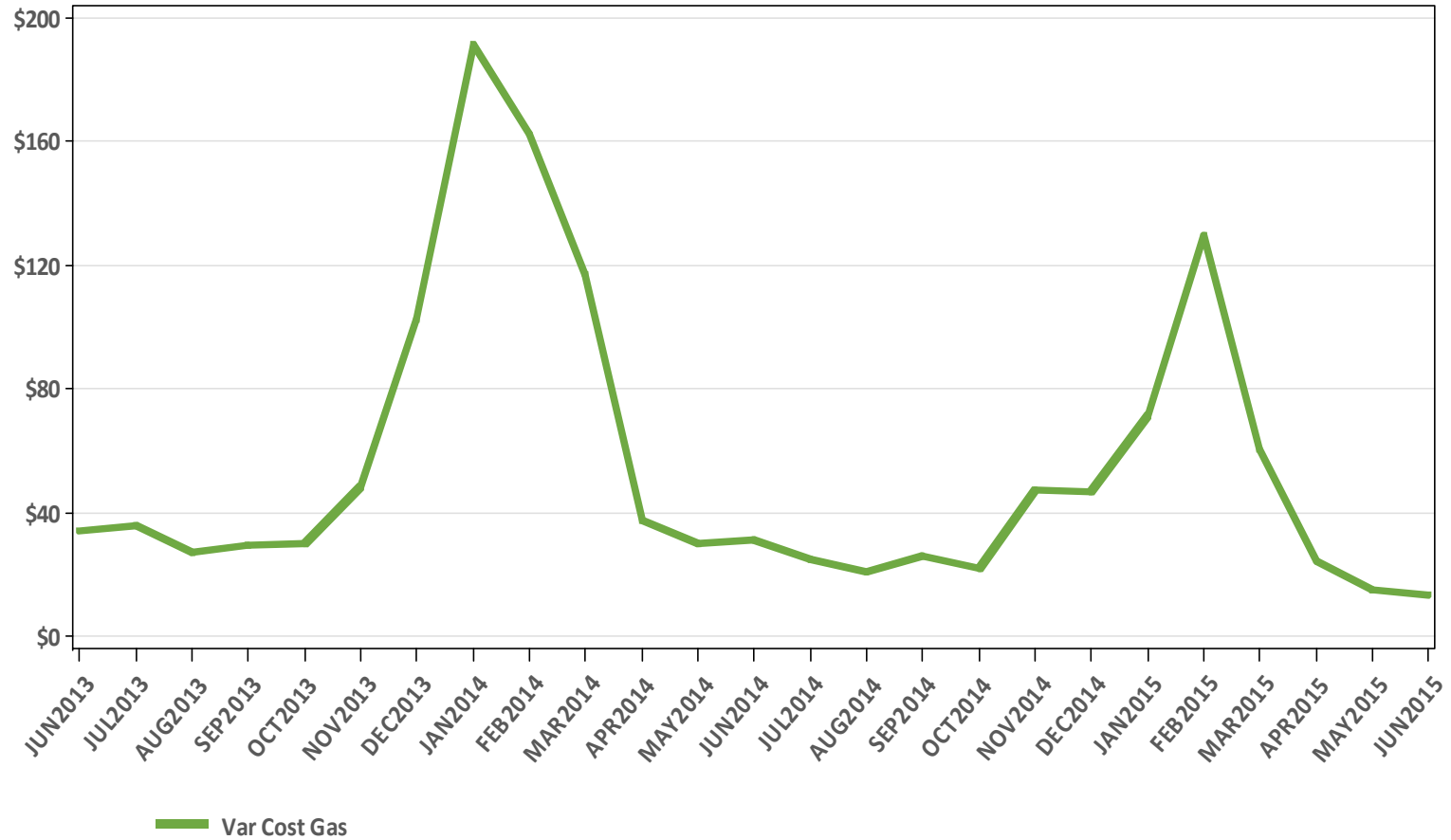
Hourly Average by Day, This Year



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



# Variable Production Cost of Natural Gas: Monthly

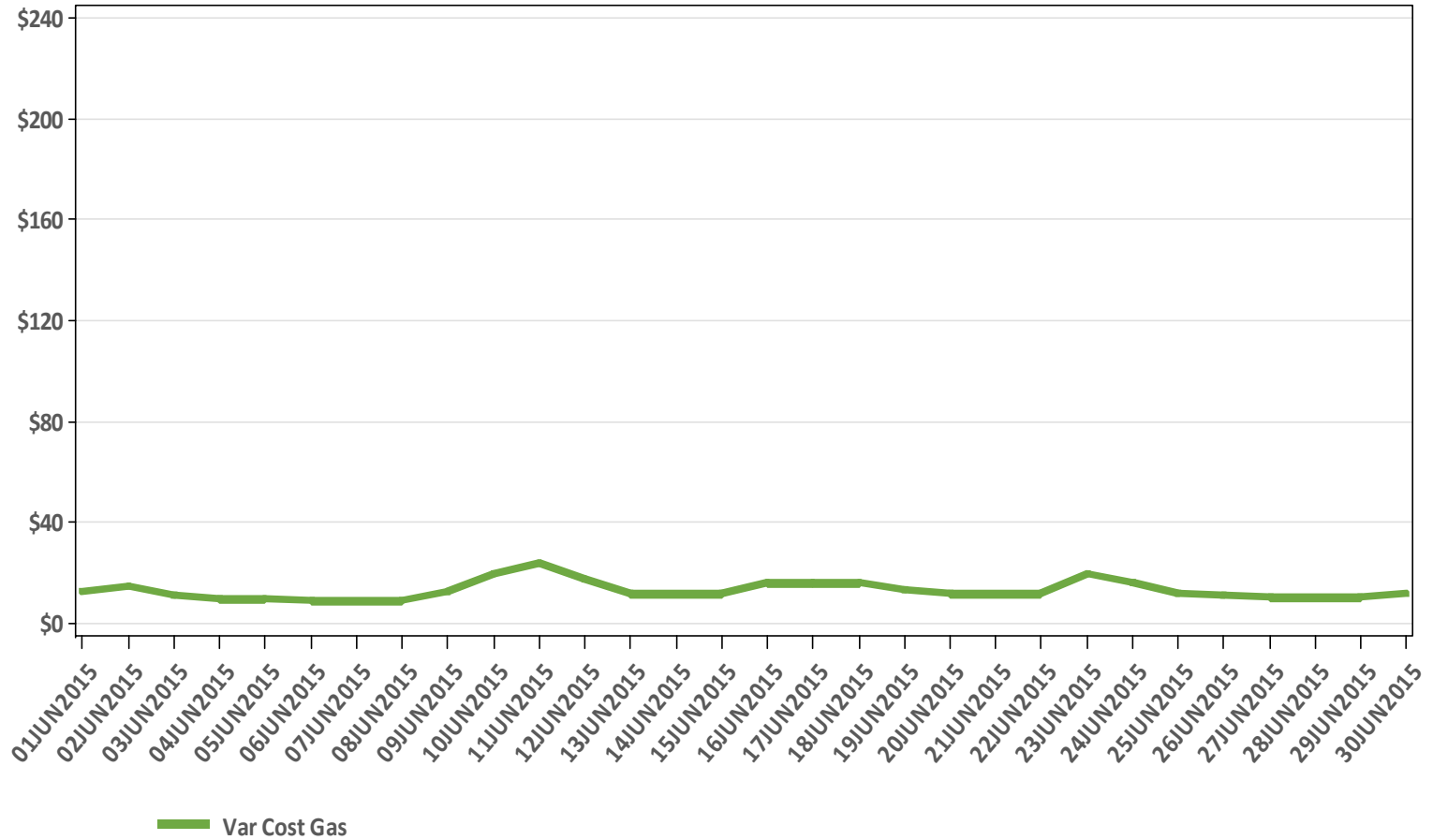


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:



# Variable Production Cost of Natural Gas: Daily



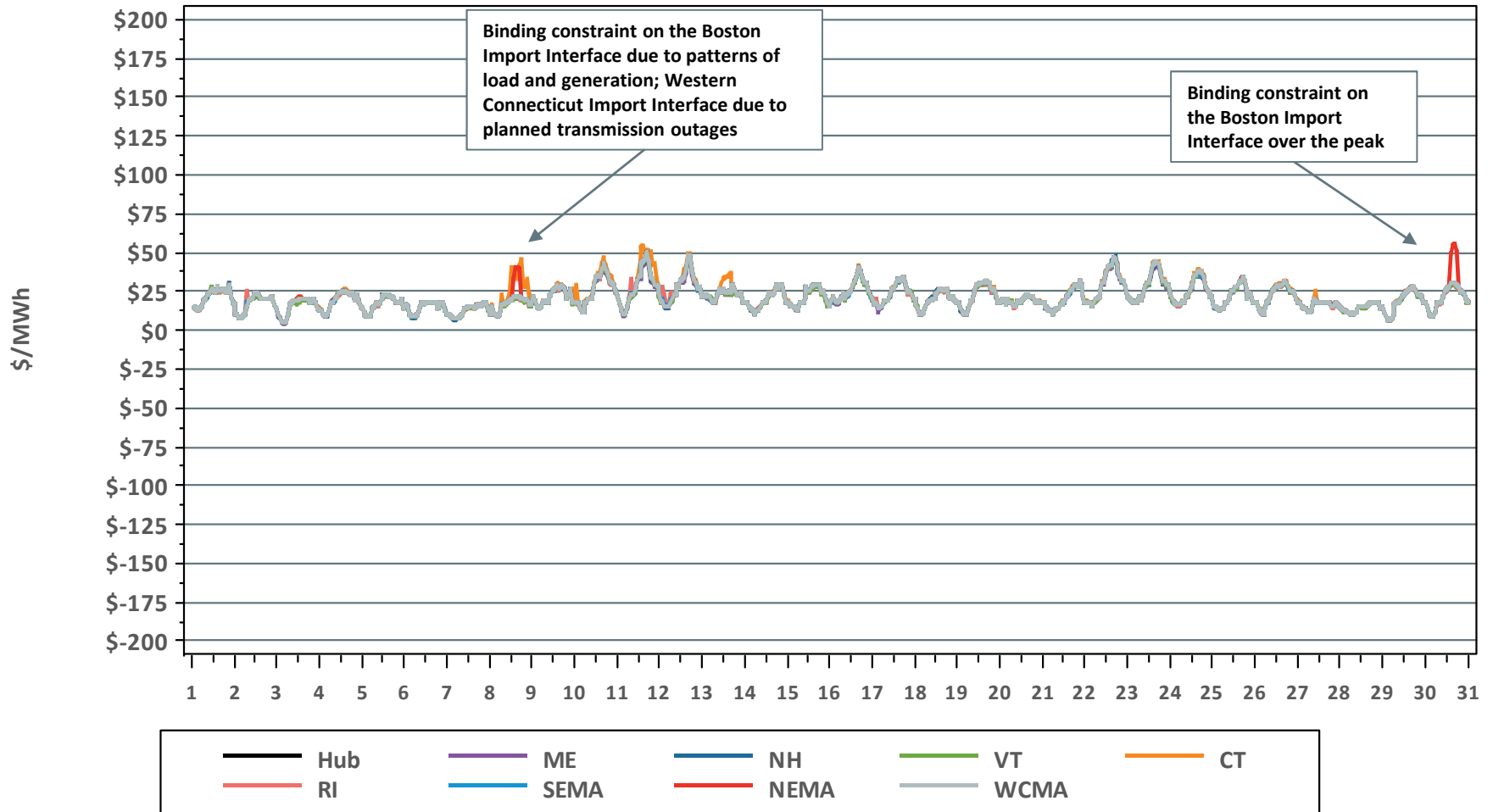
Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:

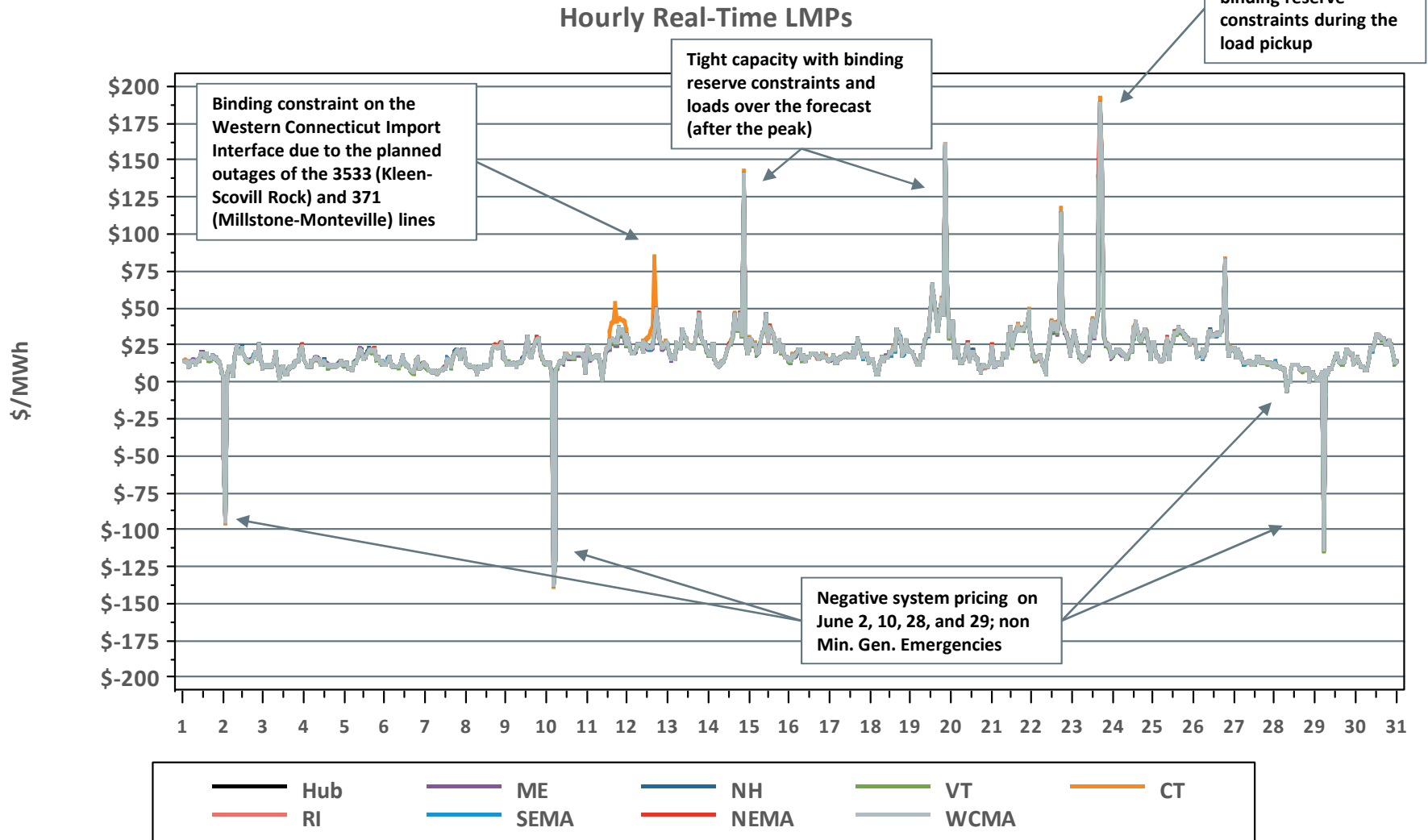


# Hourly DA LMPs, June 1-30, 2015

## Hourly Day-Ahead LMPs



# Hourly RT LMPs, June 1-30, 2015



# BACK-UP DETAIL

# LOAD RESPONSE

# Capacity Supply Obligation (CSO) MW by Demand Resource Type for July 2015

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	116.4	5.1	120.1	0.0	241.7
NH	9.1	15.1	75.3	0.0	99.5
VT	29.2	3.7	104.9	0.0	137.8
CT	77.8	109.2	74.4	310.7	572.0
RI	10.3	13.0	158.7	0.0	181.9
SEMA	10.2	10.8	206.0	0.0	227.0
WCMA	28.1	20.5	206.9	46.2	301.7
NEMA	43.9	7.5	375.0	0.0	426.4
<b>Total</b>	<b>325.1</b>	<b>184.9</b>	<b>1,321.3</b>	<b>356.9</b>	<b>2,188.1</b>

\* Real Time Demand Response

\*\* Real Time Emergency Generation

NOTE: CSO values include T&D loss factor (8%) and, as applicable, a reserve margin gross-up of either 14.3% or 16.1%, respectively, for portions of resources that selected a multi-year obligation in the FCA 1 or FCA 2. Otherwise, reserve margin gross-ups were discontinued with FCA 3.



# RELIABILITY COSTS – NET COMMITMENT PERIOD COMPENSATION (NCPC) OPERATING COSTS

# What are Daily NCPC Payments?

- 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

1 <sup>st</sup> Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2 <sup>nd</sup> Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2 <sup>nd</sup> Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR)
Voltage NCPC Payments	Reliability costs paid to resources operated by ISO-NE to provide voltage support or 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
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
OATT	Open Access Transmission Tariff



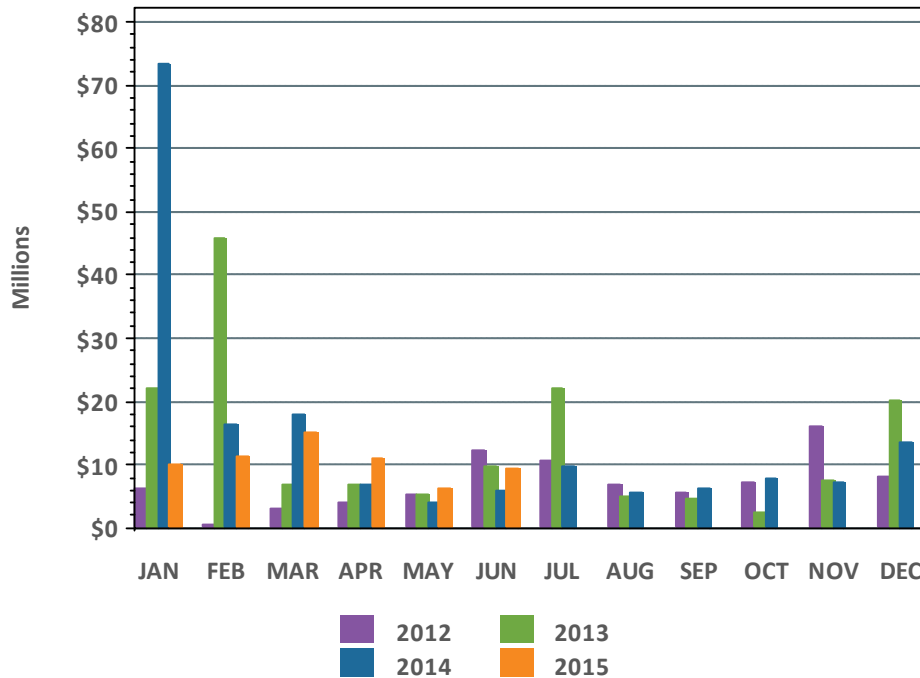
# Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 1 <sup>st</sup> Contingency	Market	DA 1 <sup>st</sup> C (excluding at external nodes) is allocated to system DALO. RT 1 <sup>st</sup> C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1 <sup>st</sup> Contingency	Market	DA 1 <sup>st</sup> C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2 <sup>nd</sup> Contingency	Market	DA and RT 2 <sup>nd</sup> C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service
System – Other	Market	Includes GPA, Min Generation Emergency, and Generator and DARD NCPC

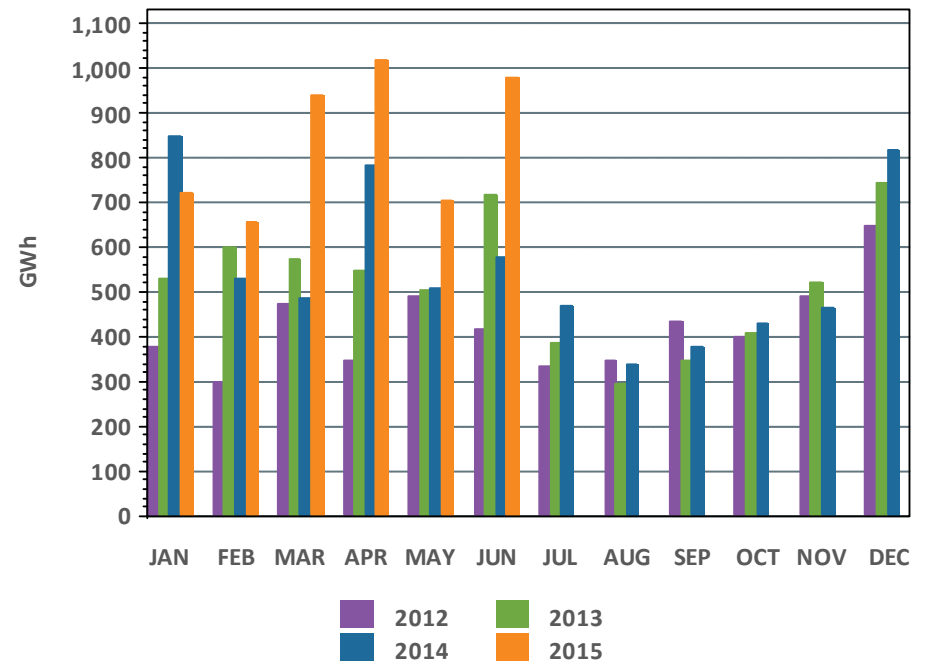


# Year-Over-Year Total NCPC Dollars and Energy

NCPC Dollars



NCPC Energy\*

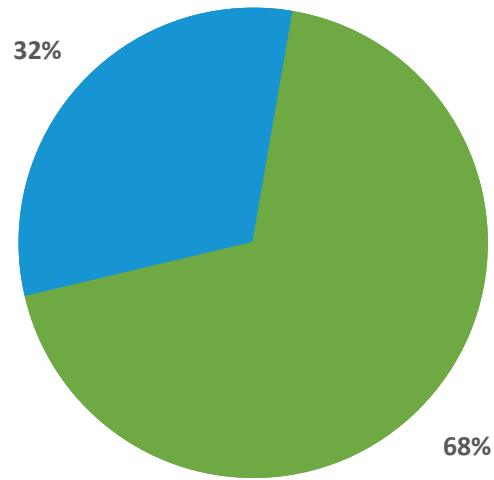


\* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1<sup>st</sup> Contingency, 2<sup>nd</sup> Contingency, Voltage, and RT Distribution) are reflected.



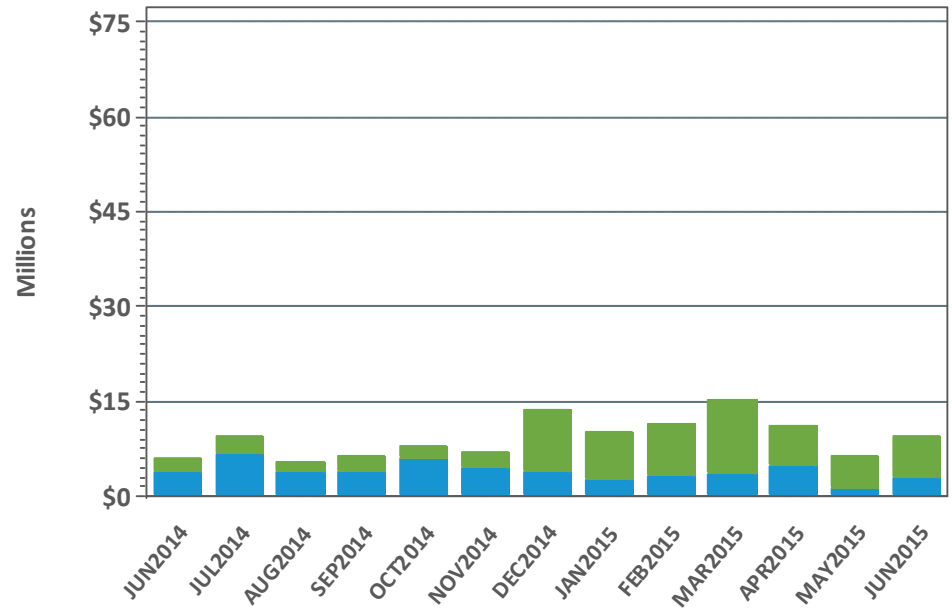
# DA and RT NCPC Charges

JUN-15 Total = \$9.44 M



Day-Ahead Real-Time

Last 13 Months

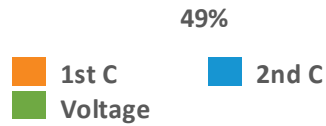
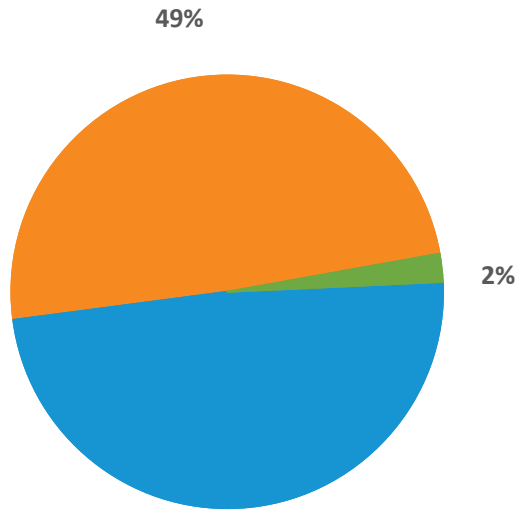


Day-Ahead Real-Time

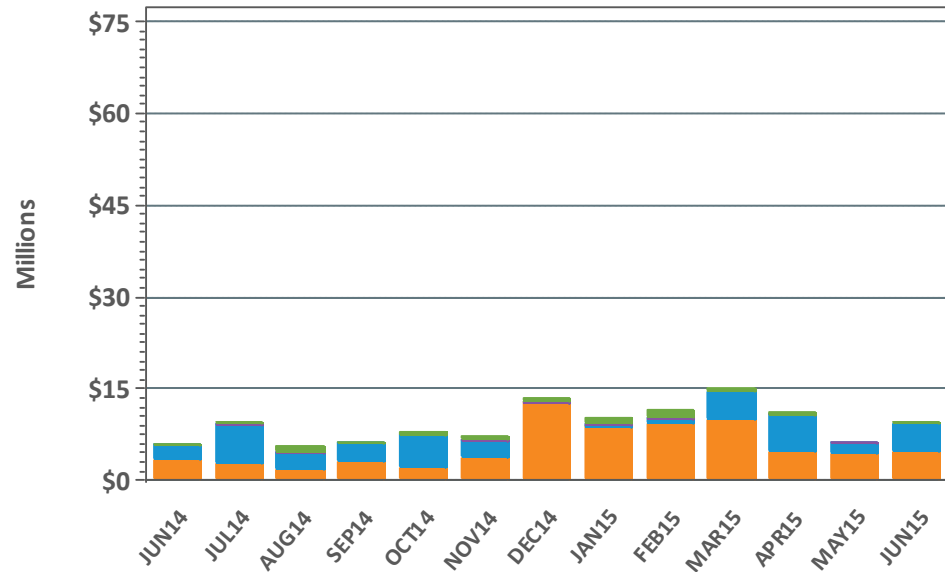


# NCPC Charges by Type

JUN-15 Total = \$9.44 M



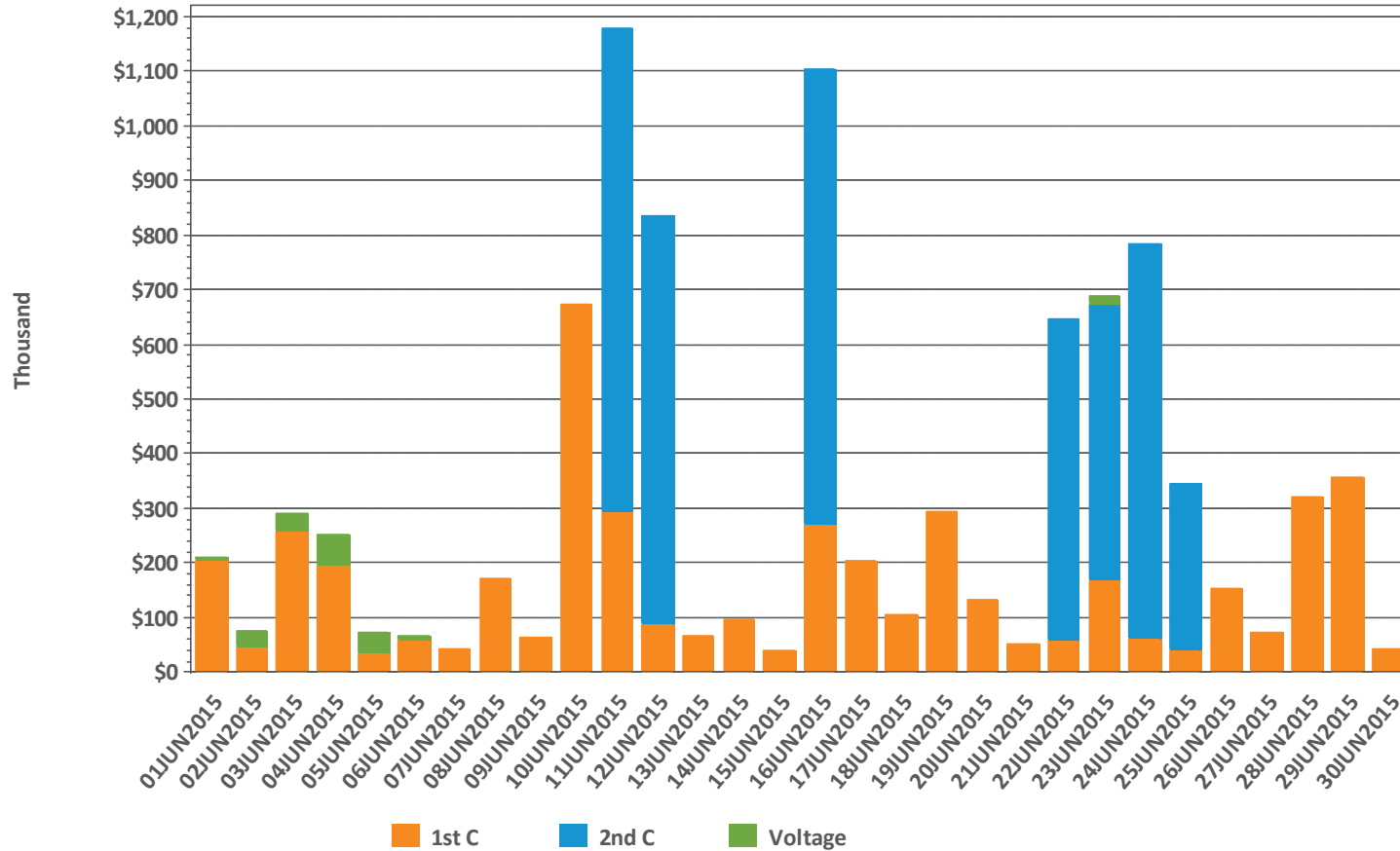
Last 13 Months



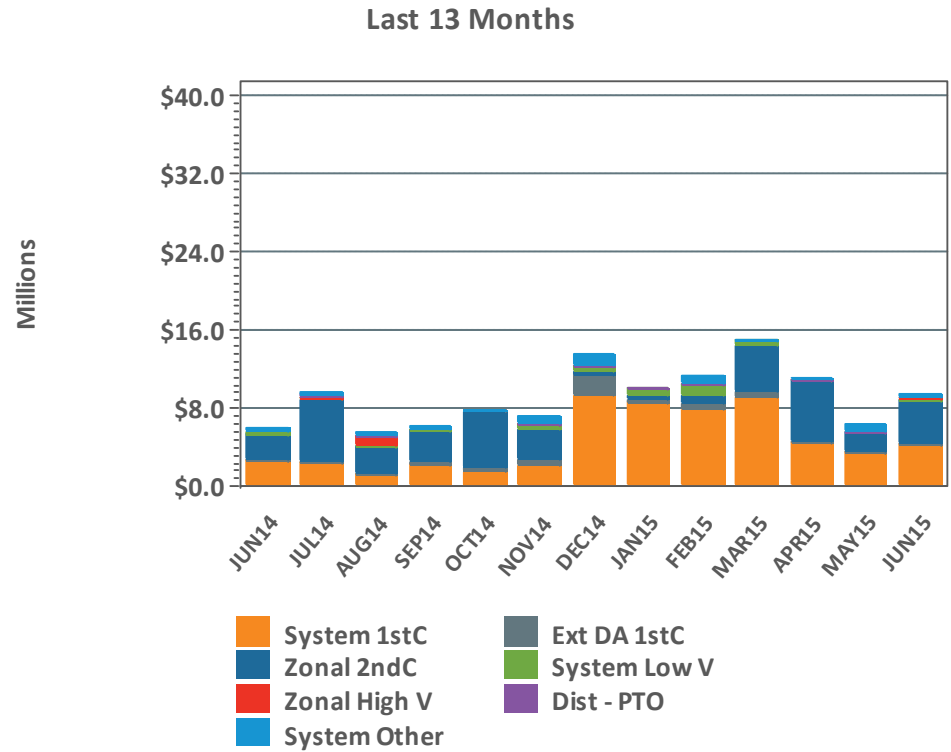
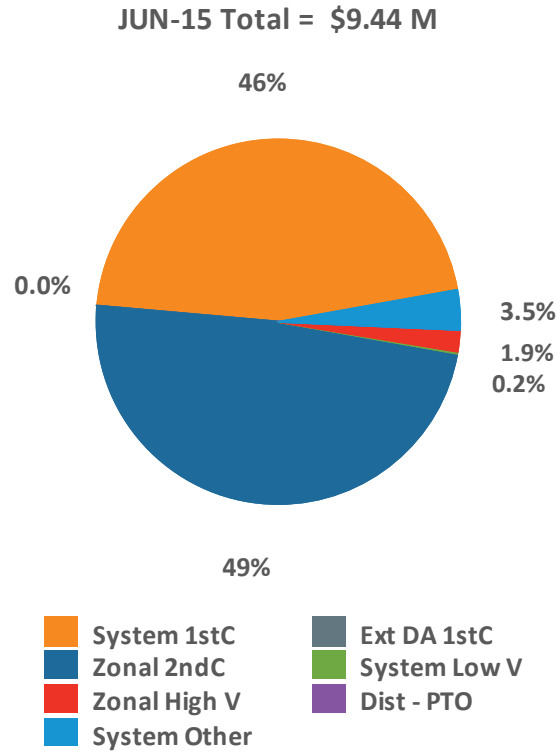
1<sup>st</sup> C – First Contingency  
 2<sup>nd</sup> C – Second Contingency  
 Distrib – Distribution  
 Voltage – Voltage



# Daily NCPC Charges by Type

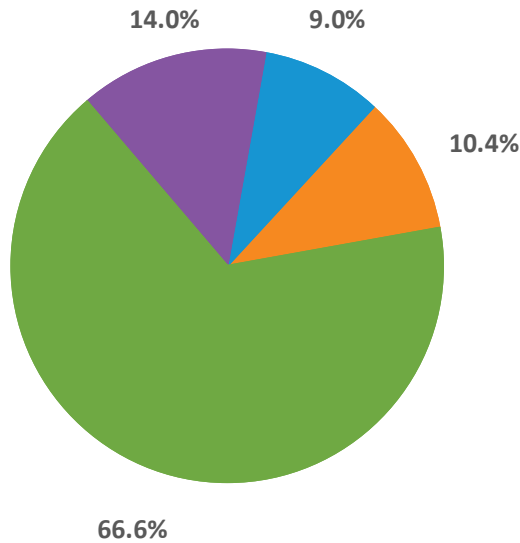


# NCPC Charges by Allocation



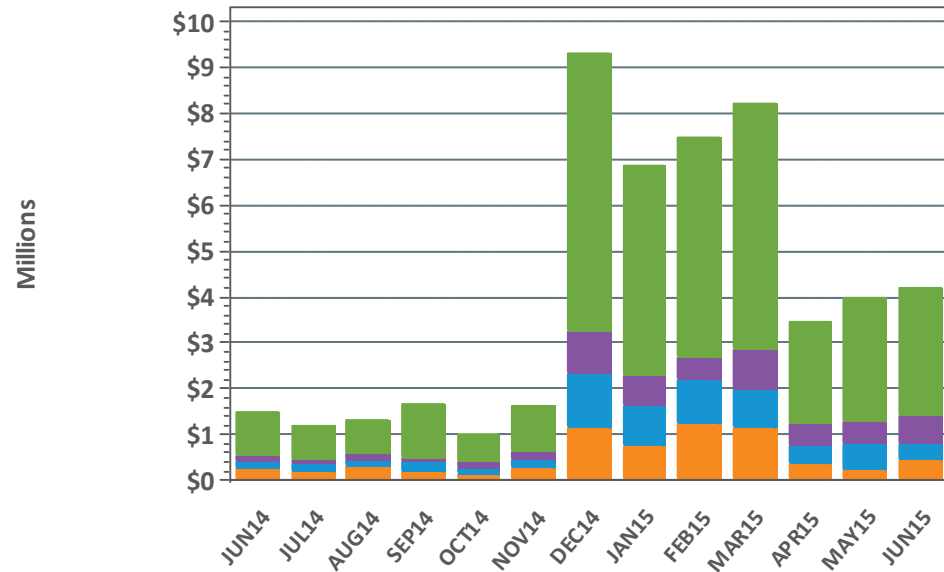
# RT First Contingency Charges by Deviation Type

JUN-15 Total = \$4.18 M

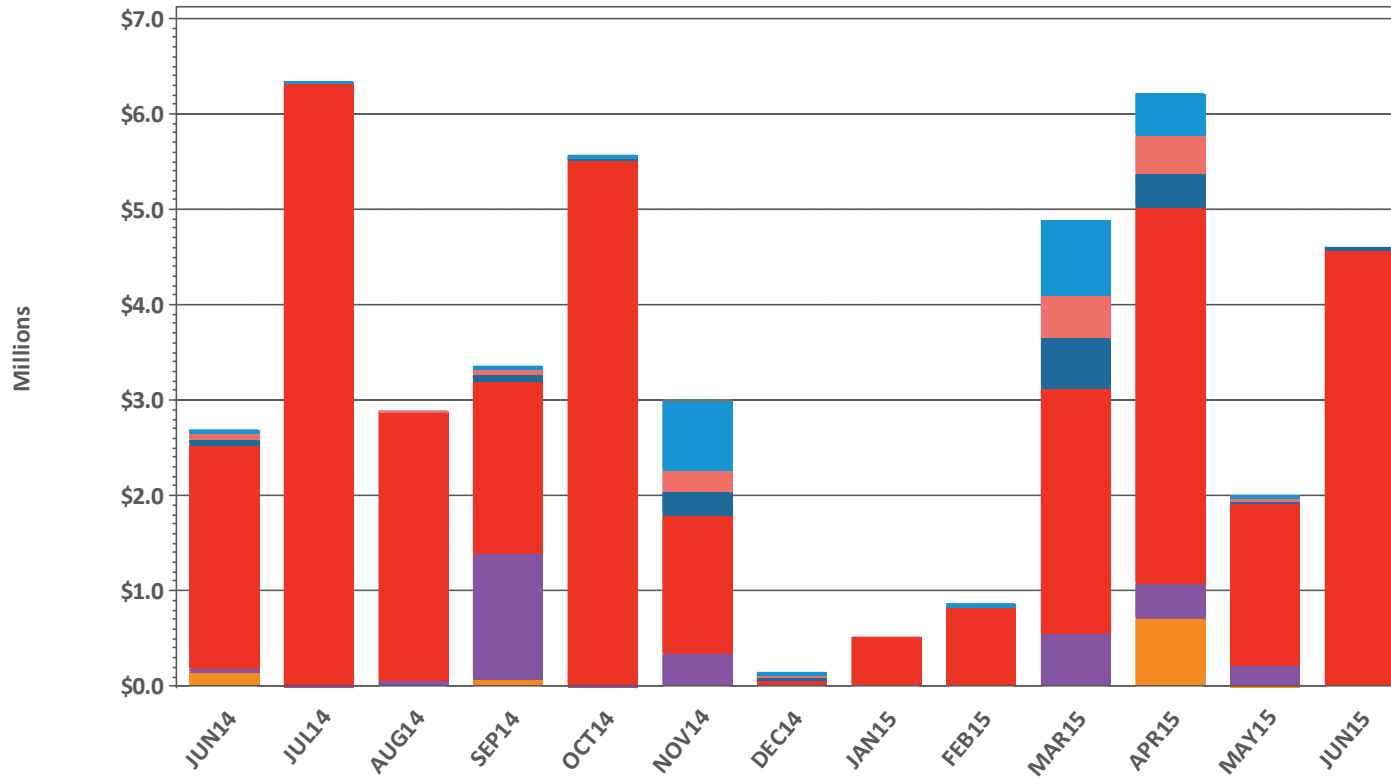


Gen – Generator deviations  
 Inc – Increment Offer deviations  
 Imp – Import deviations  
 Load – Load obligation deviations

Last 13 Months



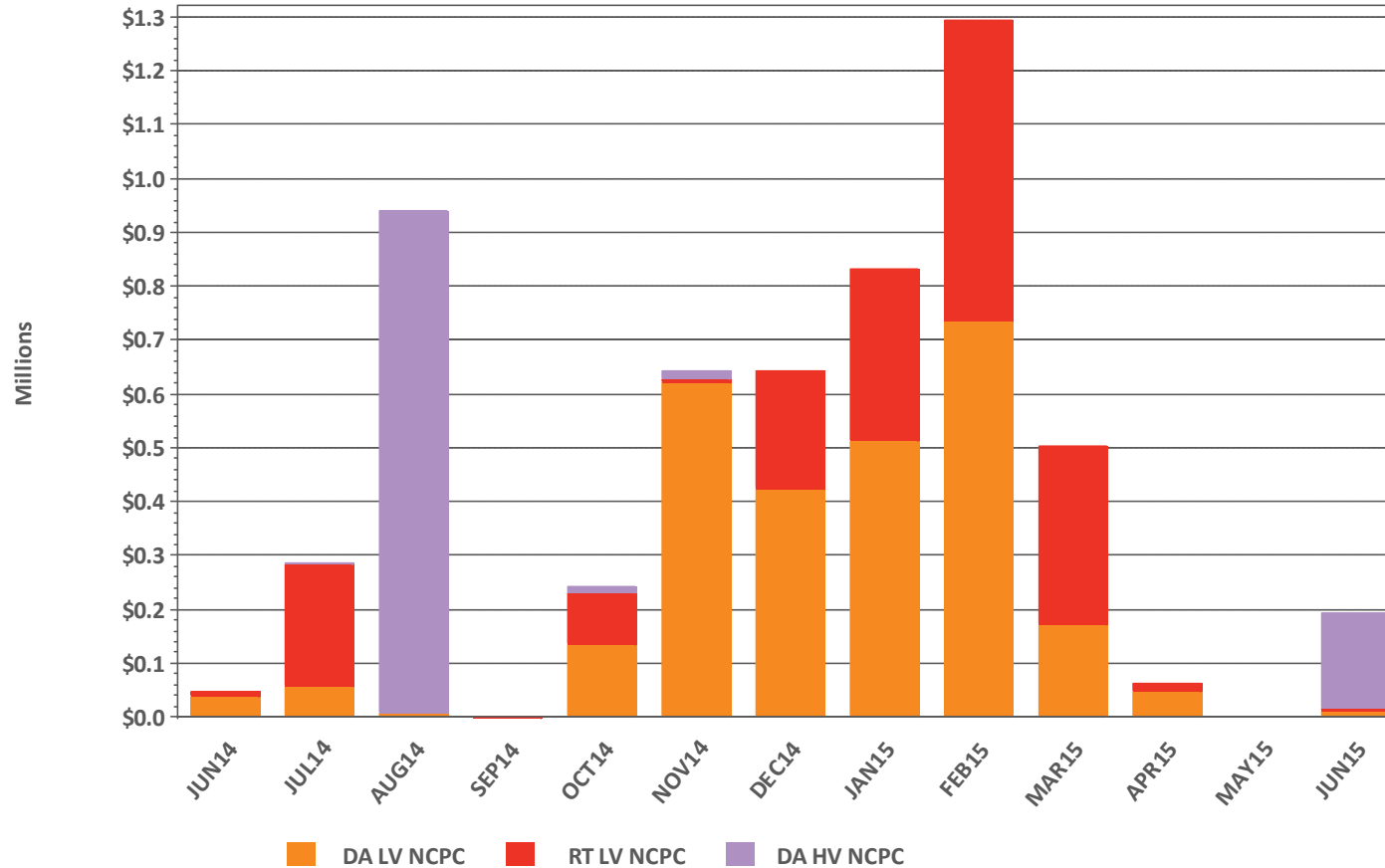
# LSCPR Charges by Zone



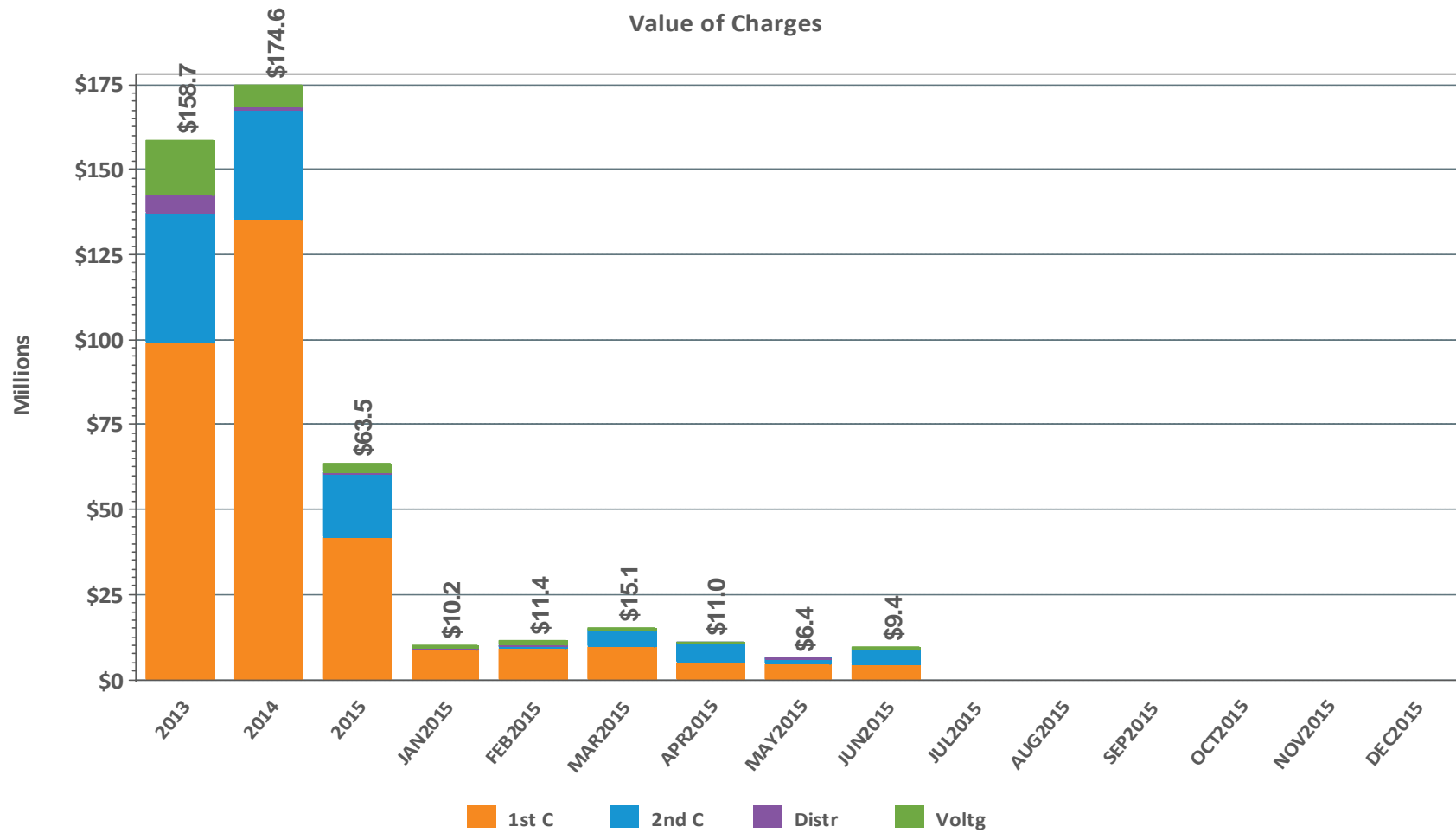
- CT – Connecticut Region
- ME – Maine Region
- NEMA – Northeast Massachusetts Region
- NH – New Hampshire Region
- RI – Rhode Island Region
- SEMA – Southeast Massachusetts Region
- VT – Vermont Region
- WCMA – Western/Central Massachusetts Region
- EXT – External Locations



# NCPC Charges for Voltage Support and High Voltage Control

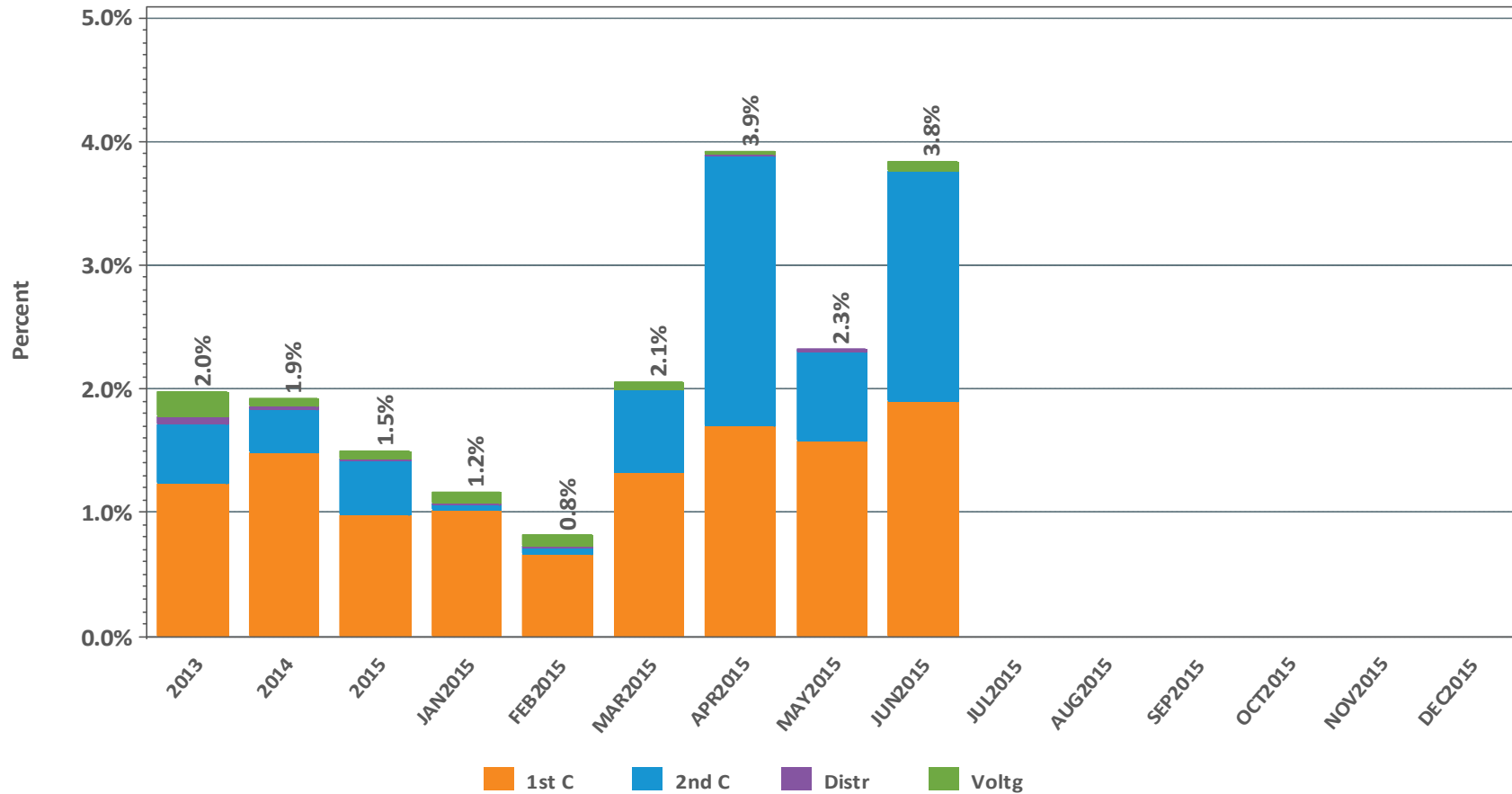


# NCPC Charges by Type

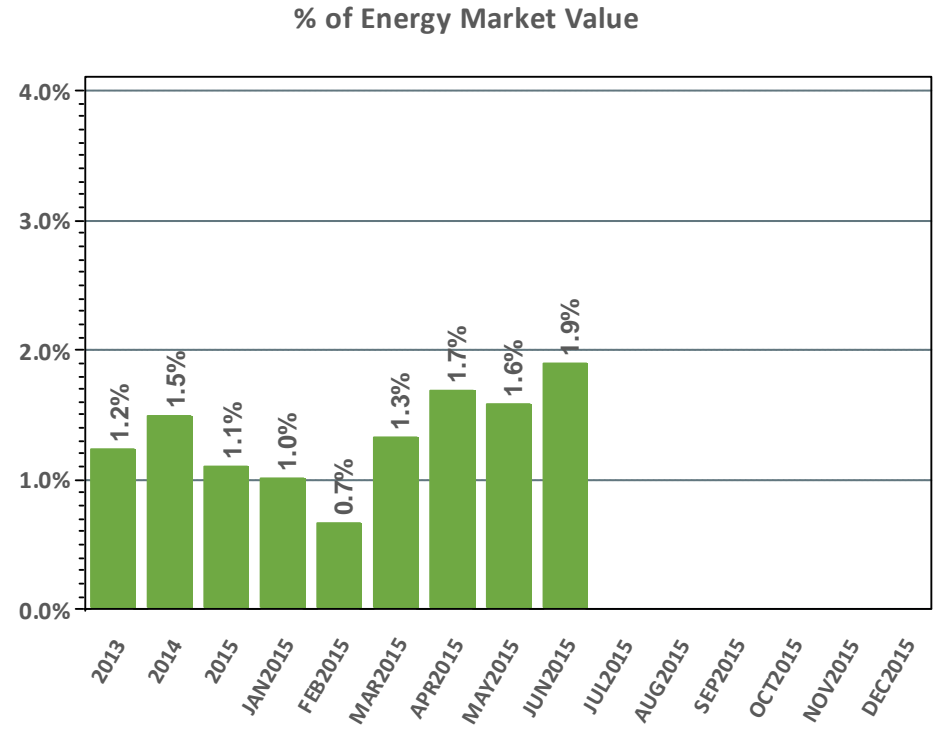
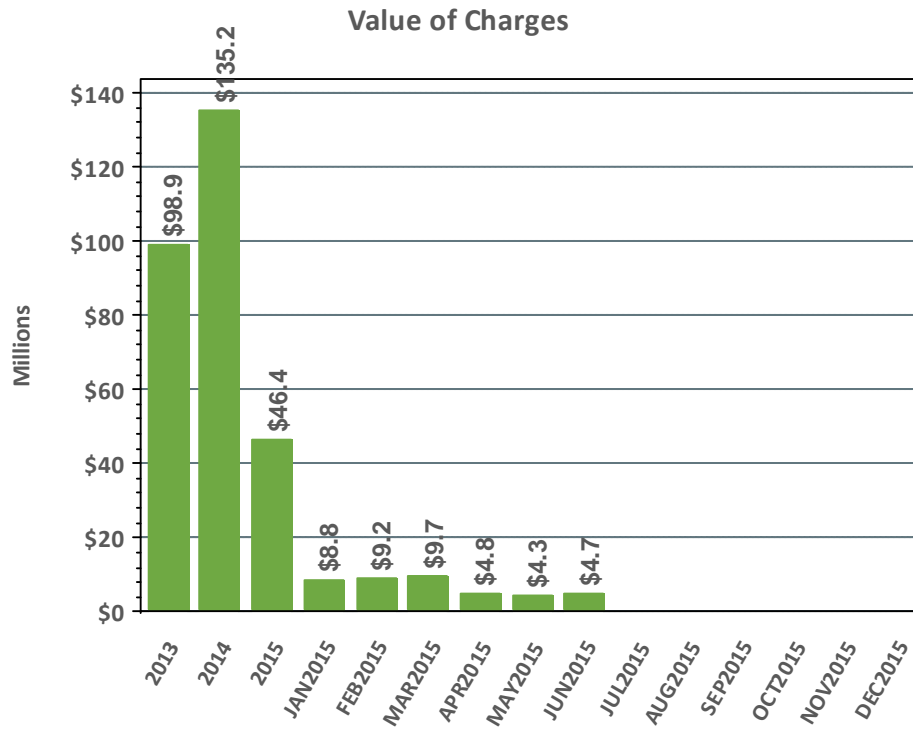


# NCPC Charges as Percent of Energy Market

NCPC By Type as Percent of Energy Market



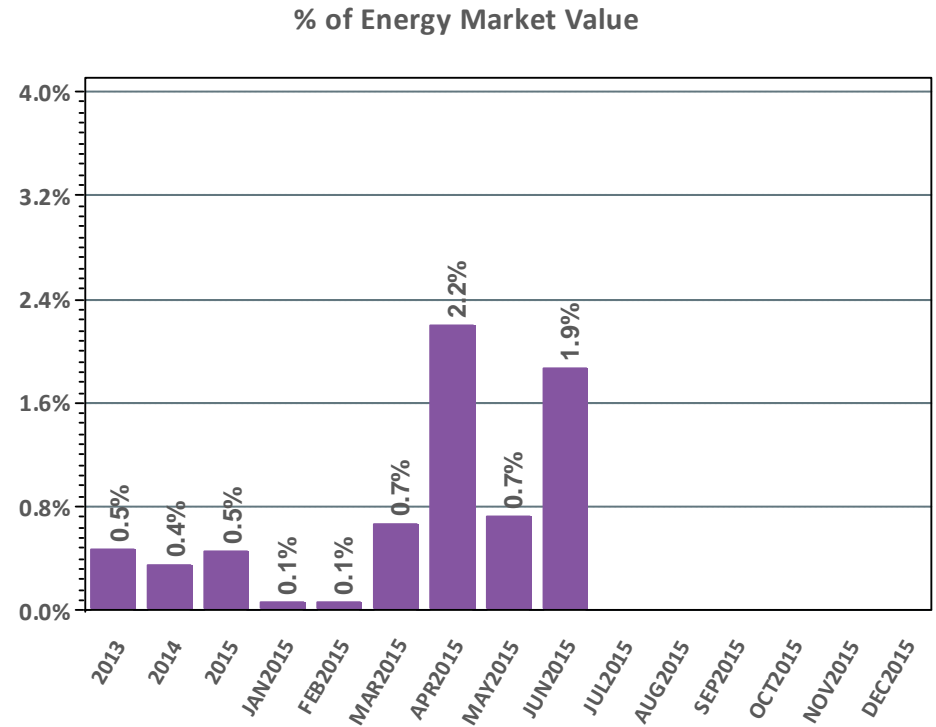
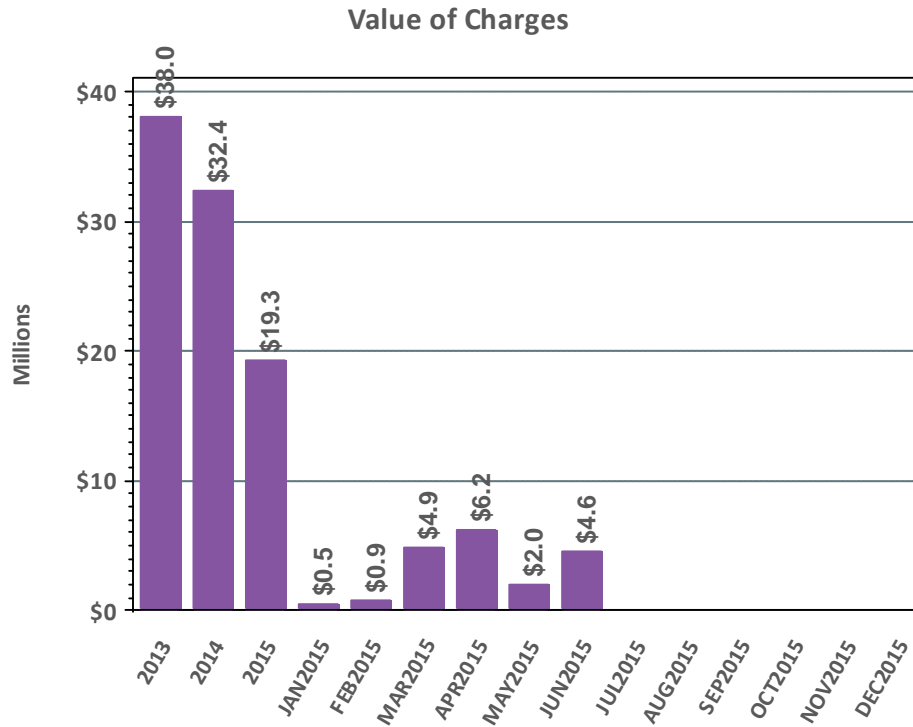
# First Contingency NCPC Charges



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 Charges

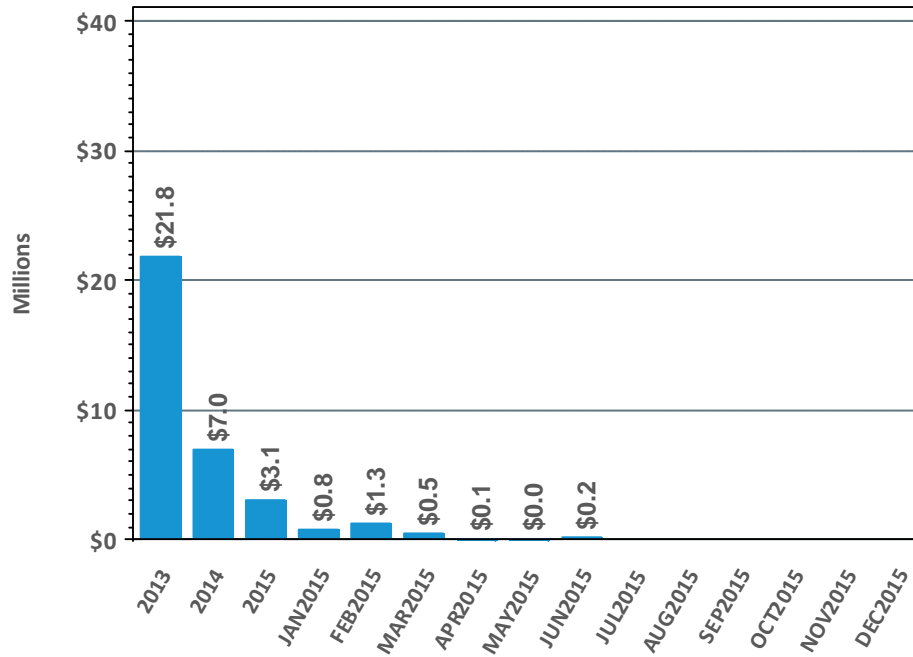


Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

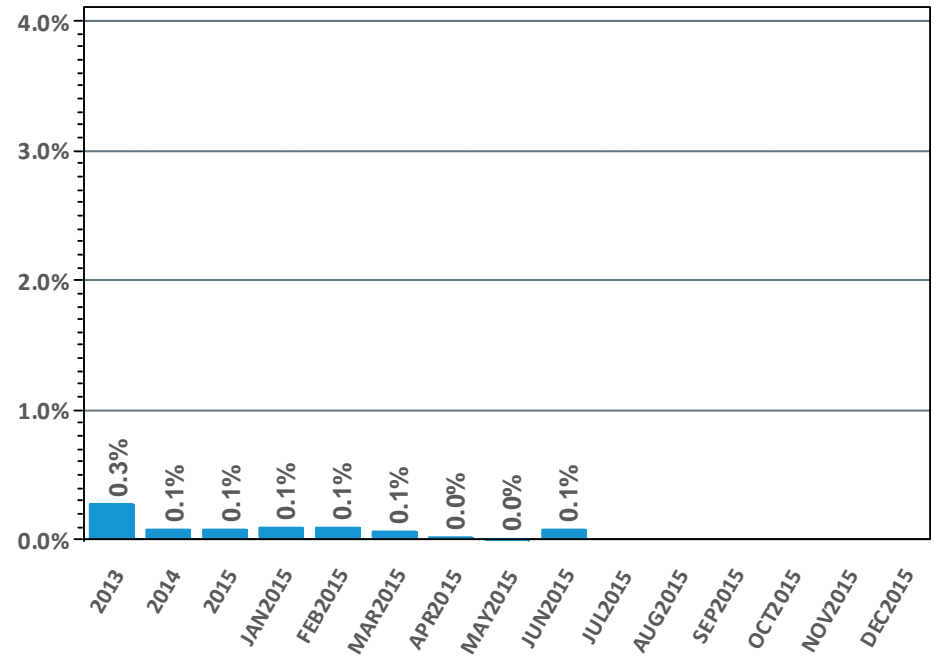


# Voltage and Distribution NCPC Charges

Value of Charges



% of Energy Market Value



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



# DA vs. RT Pricing

## The following slides outline:

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



# DA vs. RT LMPs (\$/MWh)

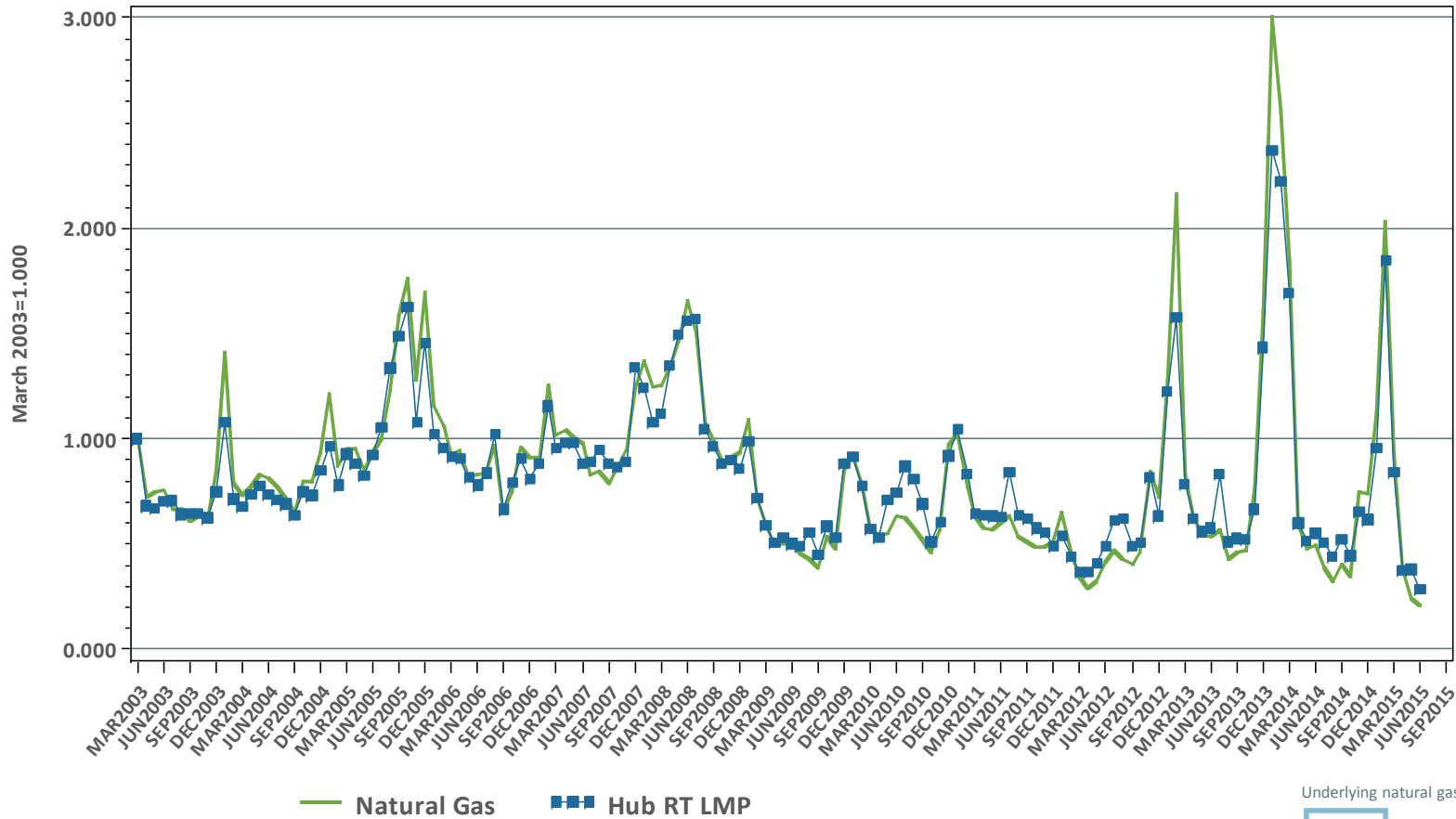
## Arithmetic Average

Year 2013	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$56.90	\$55.43	\$54.48	\$55.98	\$55.36	\$57.80	\$57.02	\$56.38	\$56.43
Real-Time	\$56.32	\$55.90	\$53.23	\$55.15	\$55.08	\$56.10	\$56.43	\$56.12	\$56.06
RT Delta %	-1.0%	0.8%	-2.3%	-1.5%	-0.5%	-2.9%	-1.0%	-0.5%	-0.7%
Year 2014	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$64.98	\$64.10	\$61.95	\$64.12	\$63.82	\$64.98	\$64.71	\$64.66	\$64.57
Real-Time	\$64.03	\$63.11	\$59.04	\$61.48	\$61.60	\$63.34	\$63.45	\$63.29	\$63.32
RT Delta %	-1.5%	-1.5%	-4.7%	-4.1%	-3.5%	-2.5%	-2.0%	-2.1%	-1.9%

June-14	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$38.30	\$38.12	\$36.46	\$37.75	\$37.56	\$37.76	\$37.79	\$38.03	\$37.92
Real-Time	\$38.24	\$37.92	\$36.52	\$37.61	\$37.24	\$37.82	\$37.89	\$37.94	\$37.92
RT Delta %	-0.2%	-0.5%	0.2%	-0.4%	-0.9%	0.1%	0.2%	-0.2%	0.0%
June-15	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	\$21.46	\$21.89	\$20.83	\$21.08	\$21.04	\$20.95	\$21.05	\$21.25	\$21.16
Real-Time	\$19.79	\$20.13	\$19.34	\$19.53	\$19.39	\$19.41	\$19.53	\$19.66	\$19.61
RT Delta %	-7.8%	-8.1%	-7.2%	-7.3%	-7.9%	-7.4%	-7.2%	-7.5%	-7.3%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-44.0%	-42.6%	-42.9%	-44.2%	-44.0%	-44.5%	-44.3%	-44.1%	-44.2%
Yr over Yr RT	-48.2%	-46.9%	-47.1%	-48.1%	-47.9%	-48.7%	-48.5%	-48.2%	-48.3%



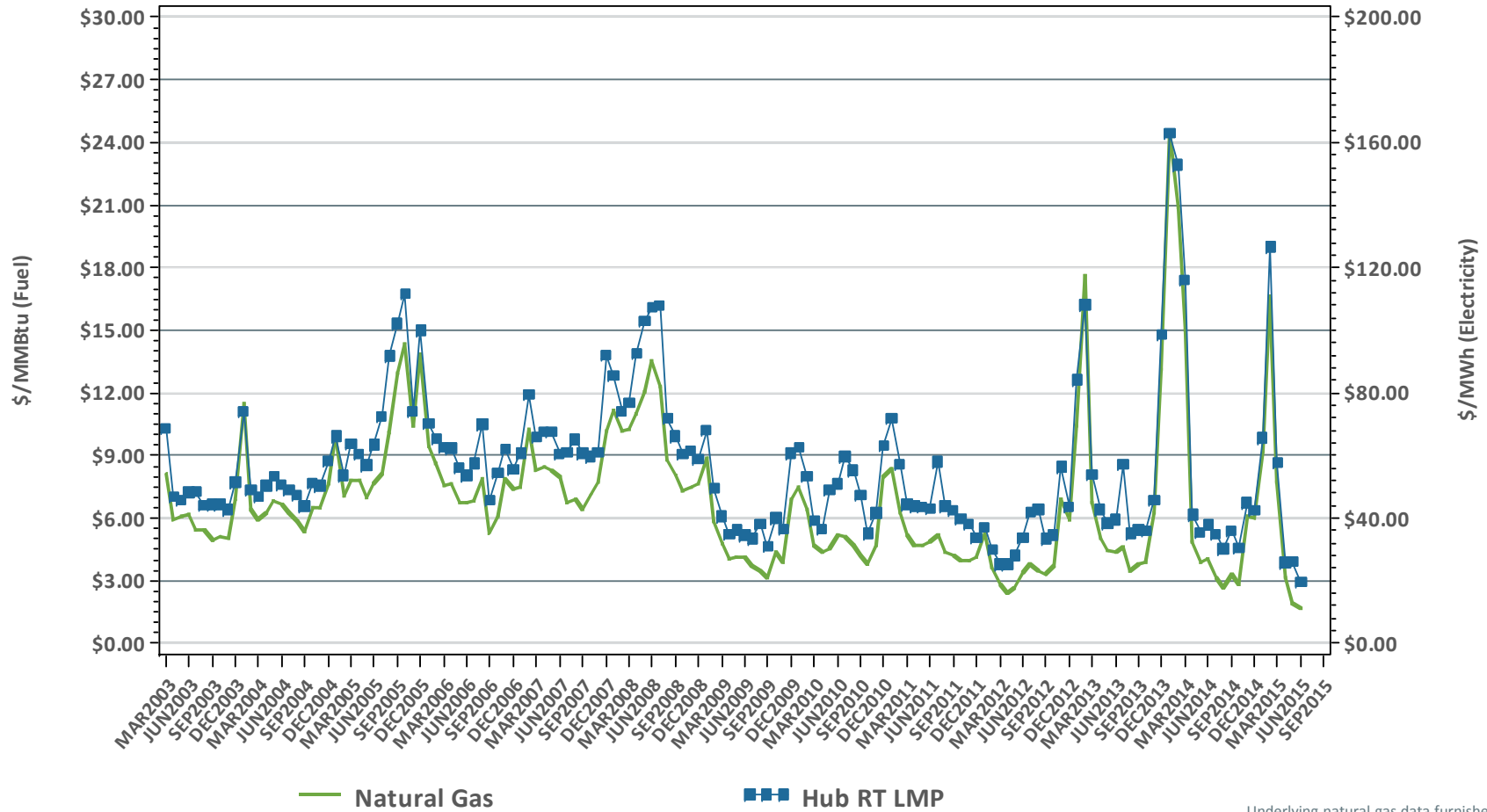
# Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:



# Monthly Average Fuel Price and RT Hub LMP

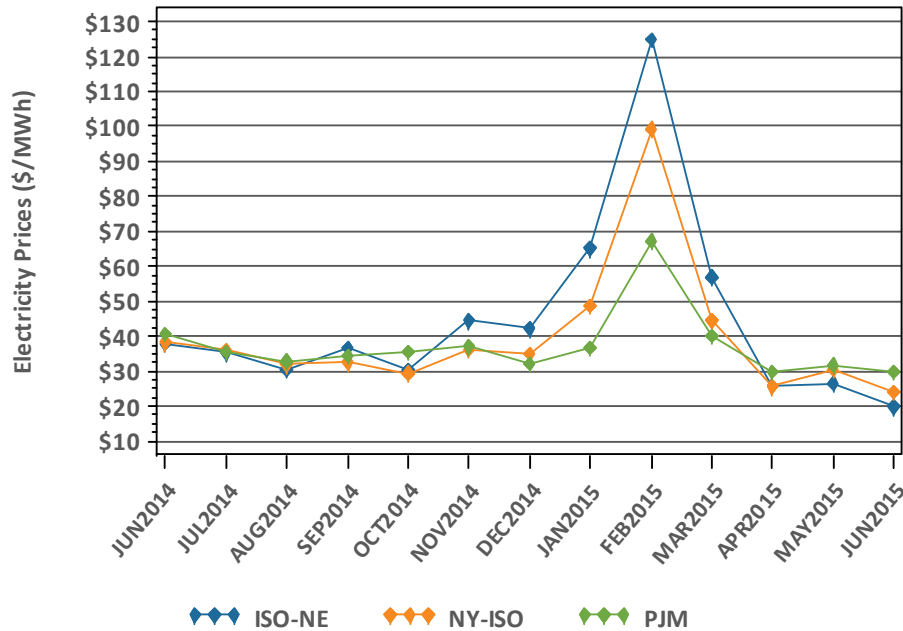


Underlying natural gas data furnished by:



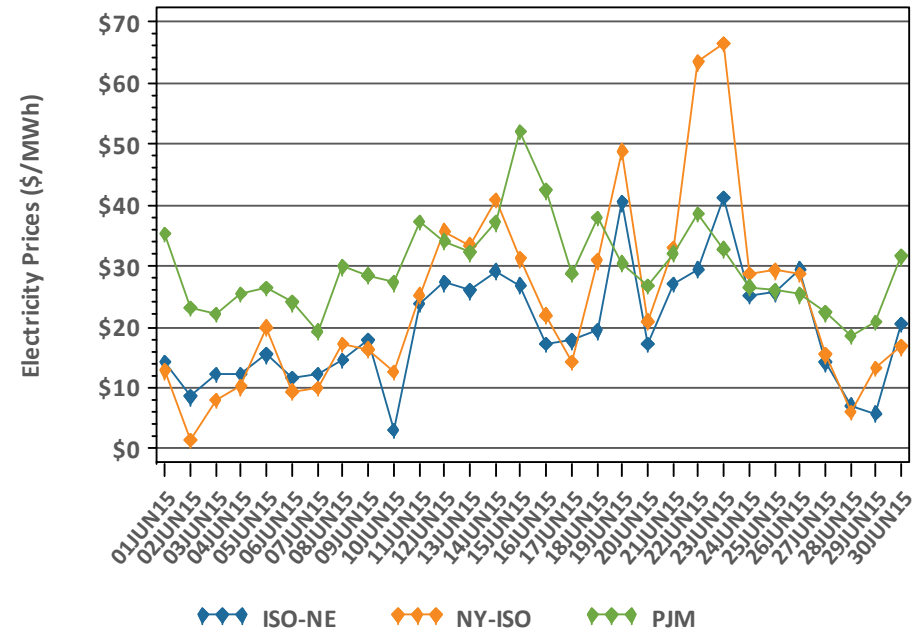
# New England, NY, and PJM Real Time Prices

Monthly, Last 13 Months



\*Note: Hourly average prices are shown.

Daily: This Month

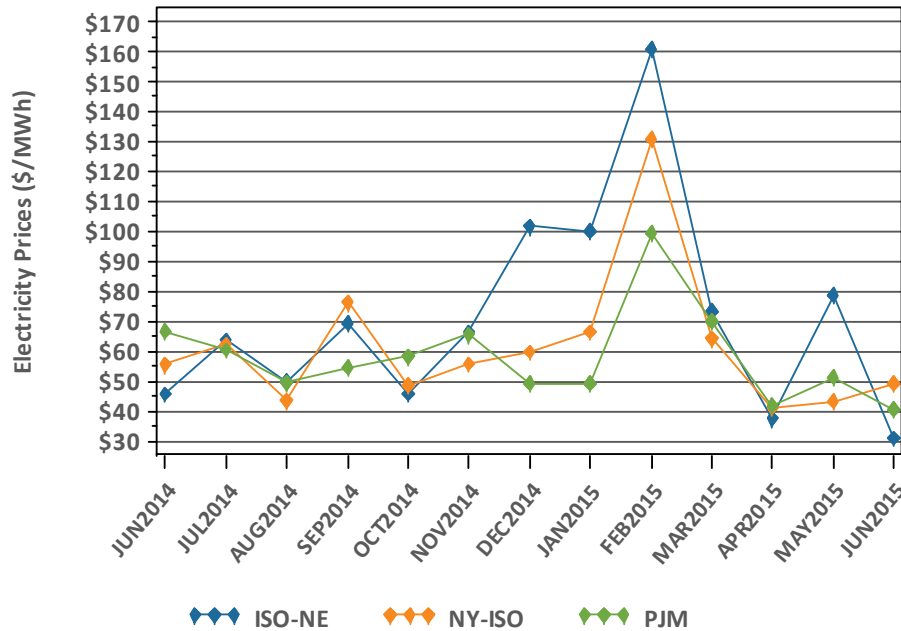


\*Note: Hourly average prices are shown.

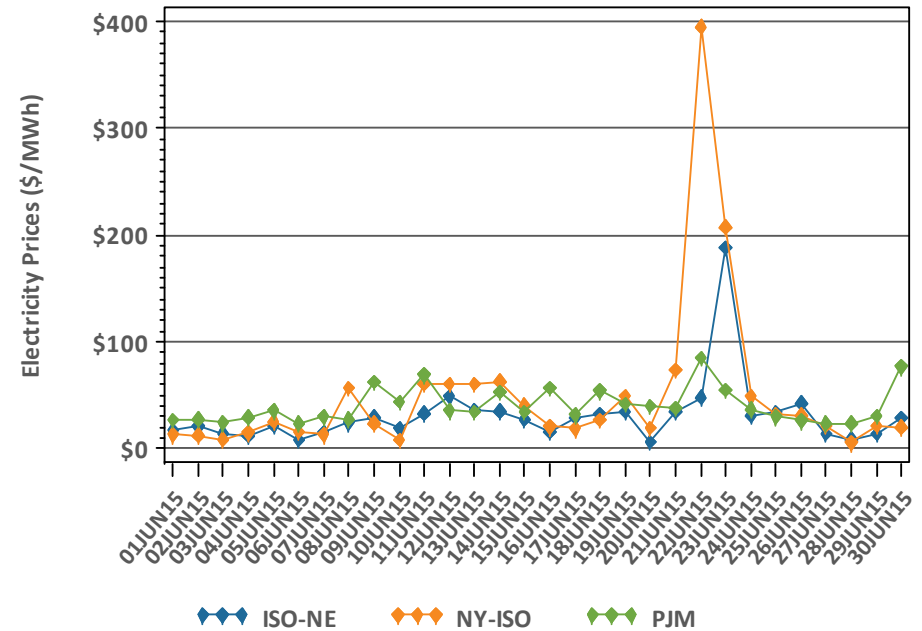


# New England, NY, and PJM Real Time Prices (Peak Hour)

Monthly, Last 13 Months



Daily: This Month



\*Forecasted New England peak hour is reflected.



## Reserve Market Results – June 2015

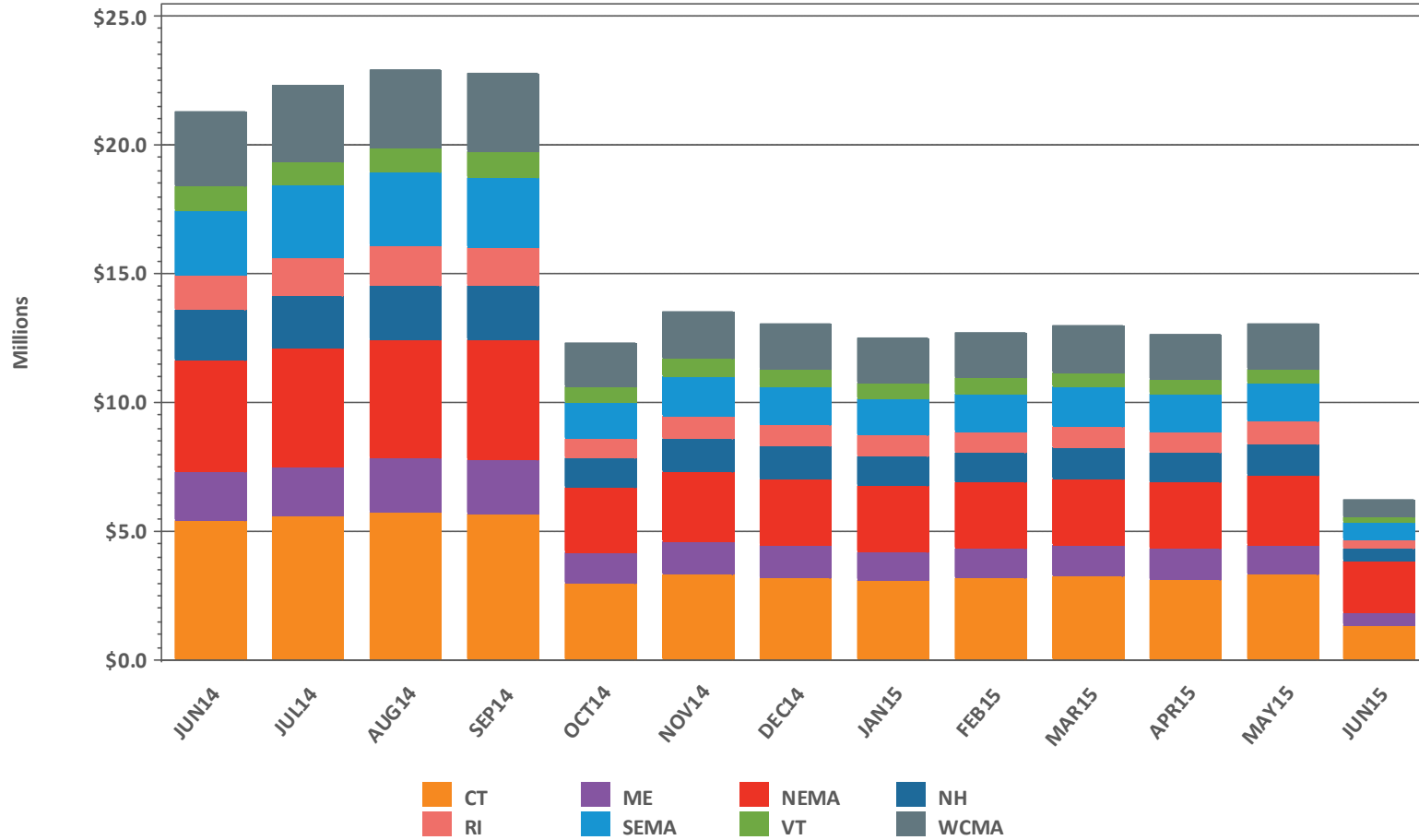
- Maximum potential Forward Reserve Market payments of \$6.5M were reduced by credit reductions of \$85K, failure-to-reserve penalties of \$136K and failure-to-activate penalties of \$0, resulting in a net payout of \$6.2M or 97% of maximum
  - Rest of System: \$2.44M/\$2.55M (96%)
  - Southwest Connecticut: \$0.45M/\$0.46M (99%)
  - Connecticut: \$1.59M/\$1.60M (99%)
  - NEMA: \$1.76M/\$1.85M (95%)
- \$1.6M total Real-Time credits were reduced by \$636K in Forward Reserve Energy Obligation Charges for a net of \$958K in Real-Time Reserve payments
  - Rest of System: 81 hours, \$580K
  - Southwest Connecticut: 81 hours, \$231K
  - Connecticut: 81 hours, \$68K
  - NEMA: 81 hours, \$80K

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



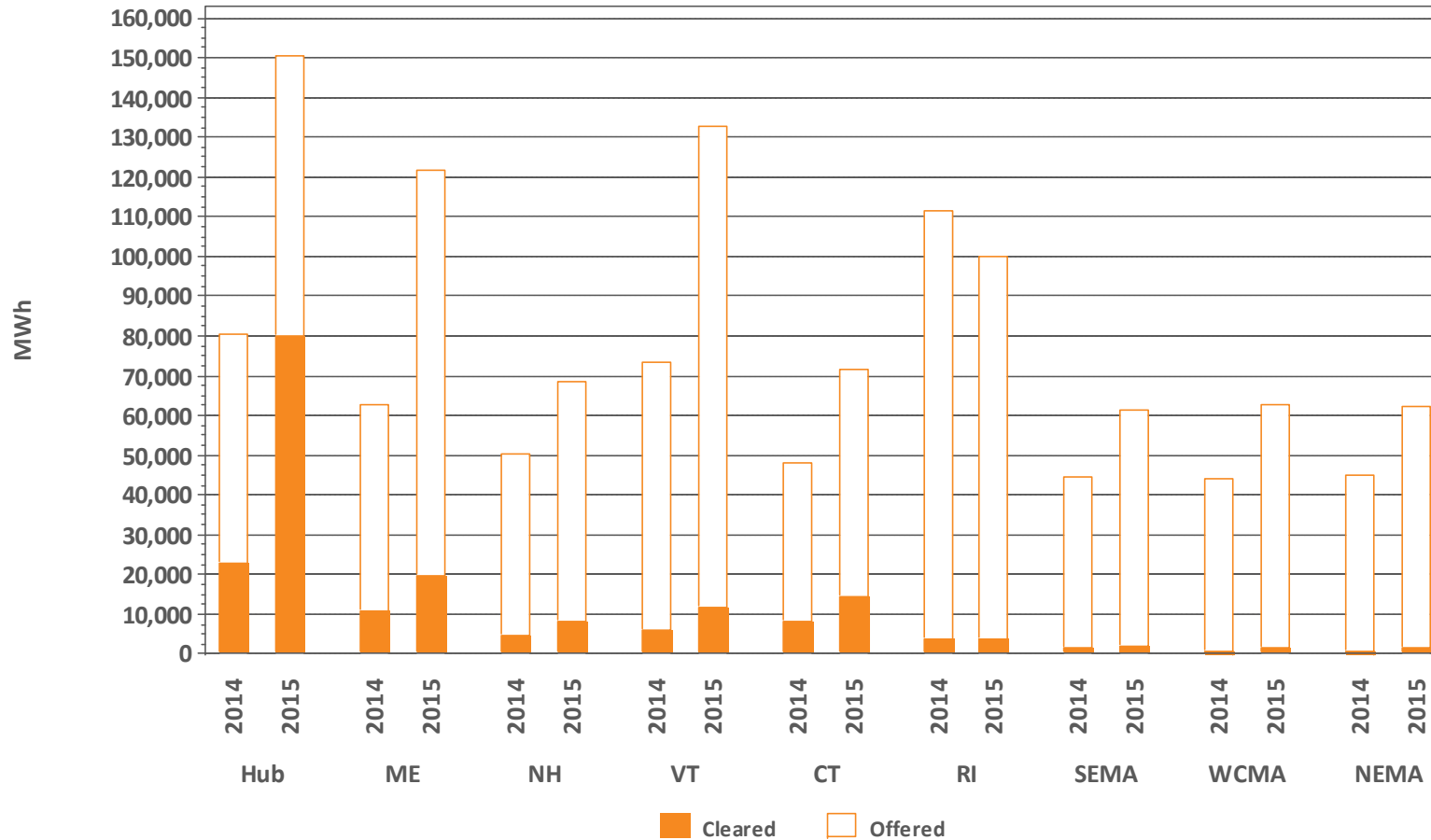
# LFRM Charges to Load by Load Zone (\$)

LFRM Charges by Zone, Last 13 Months



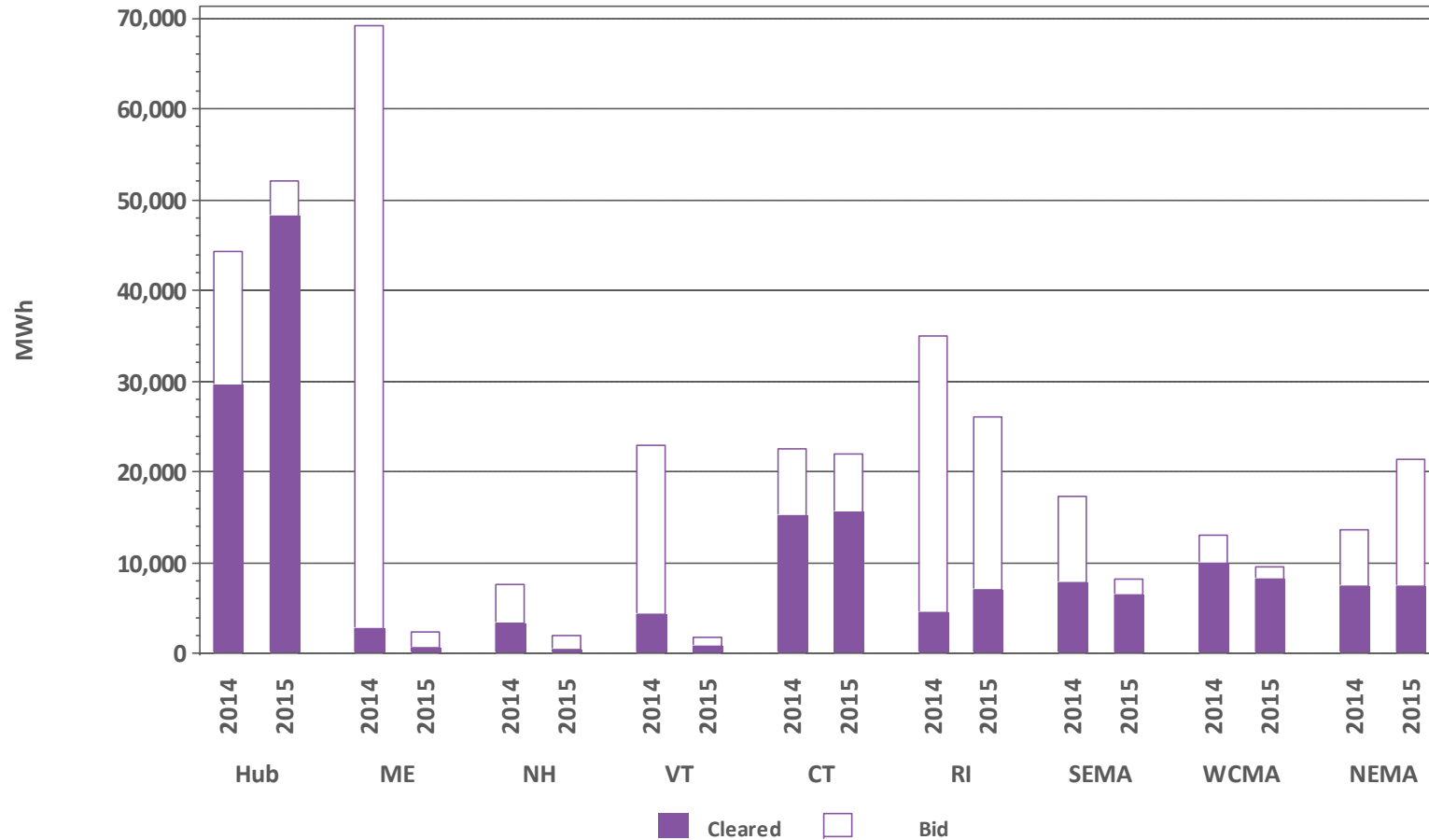
# Zonal Increment Offers and Cleared Amounts

June Monthly Totals by Zone

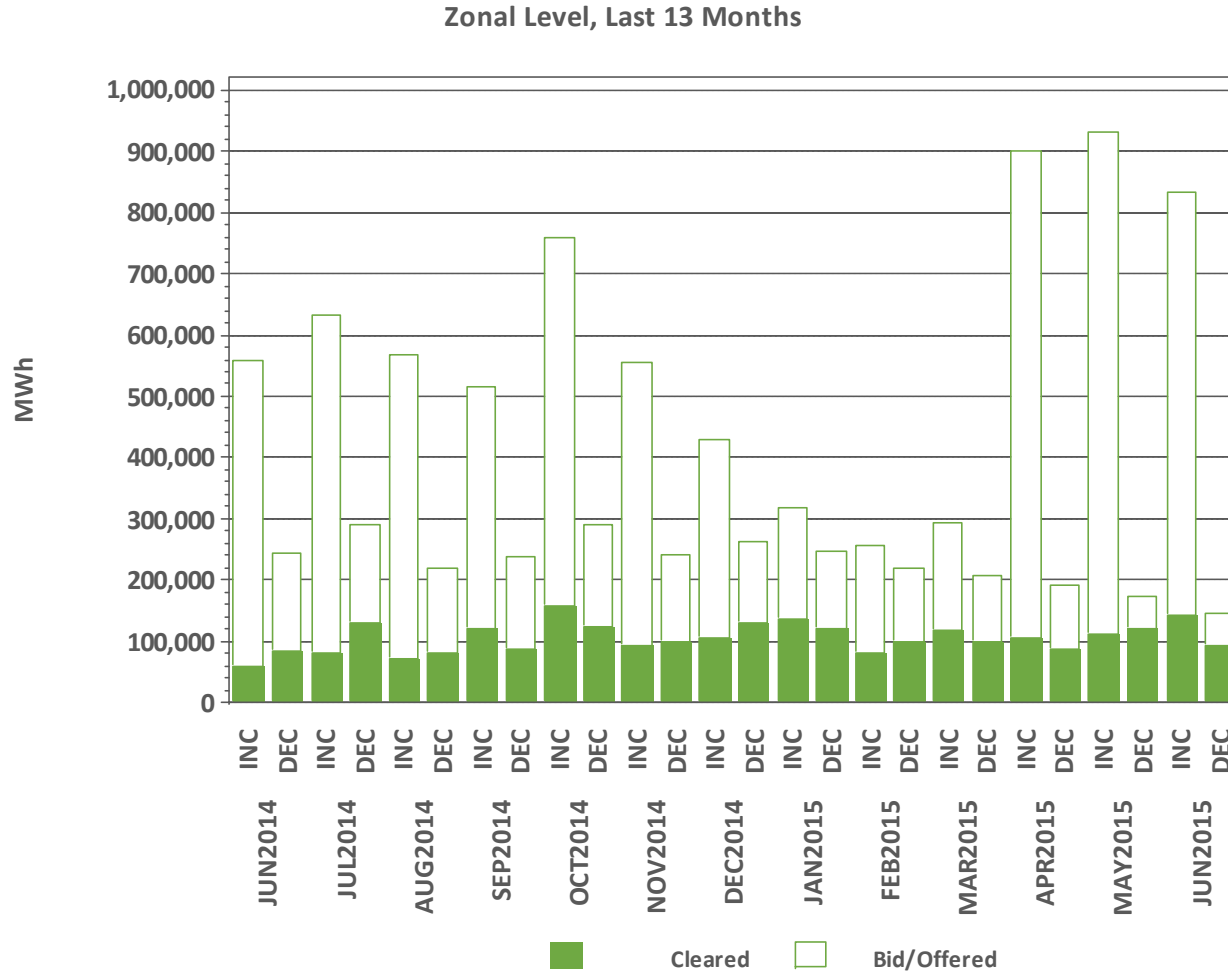


# Zonal Decrement Bids and Cleared Amounts

June Monthly Totals by Zone



# Total Increment Offers and Decrement Bids

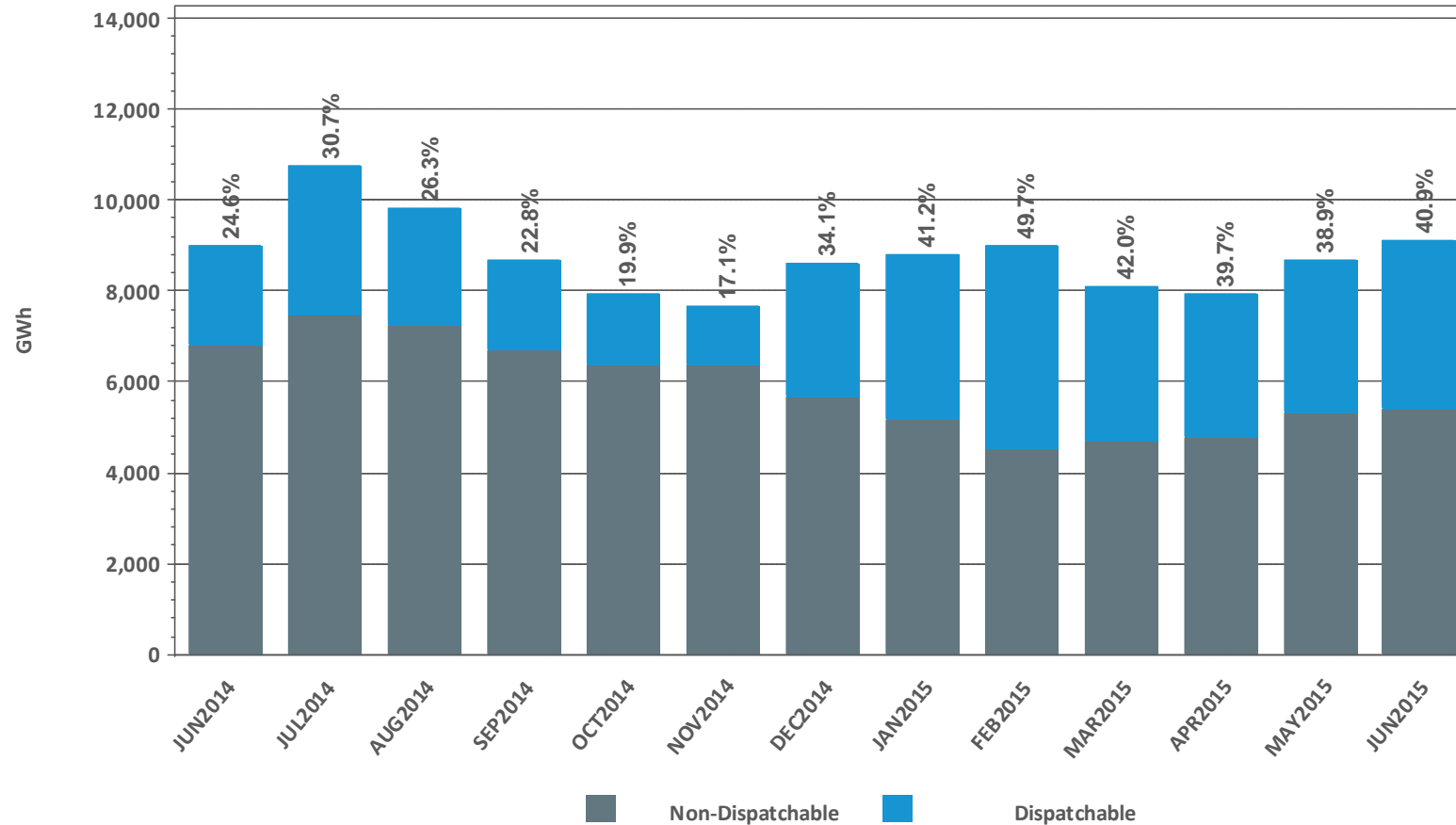


Data excludes nodal offers and bids



# Dispatchable vs. Non-Dispatchable Generation

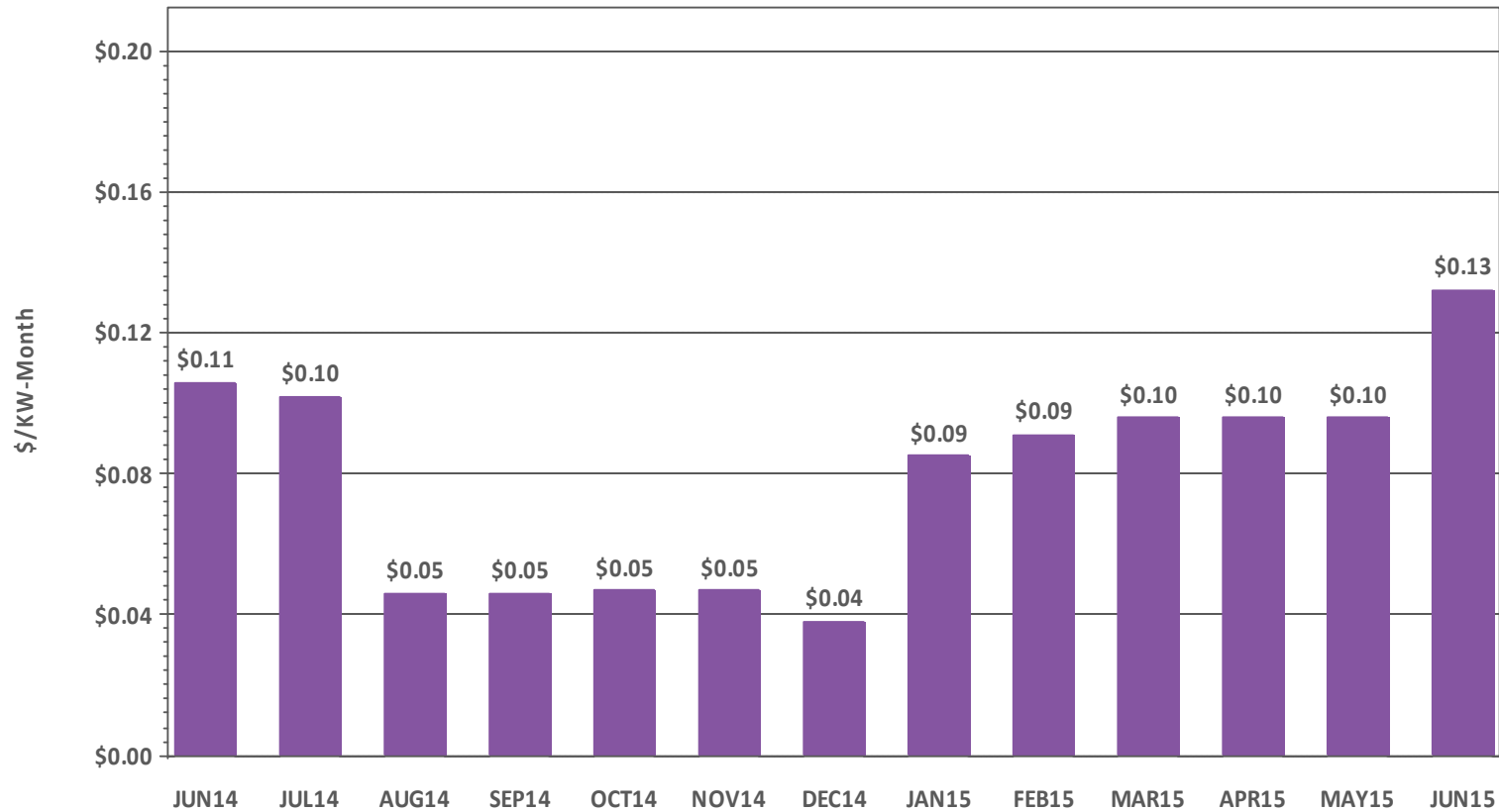
Total Monthly Energy; Dispatchable % Shown



\* Dispatchable MWh here are defined to be generation output that is not self-scheduled (i.e, not self-committed or 'must run' by the customer).



# Rolling Average Peak Energy Rent (PER)

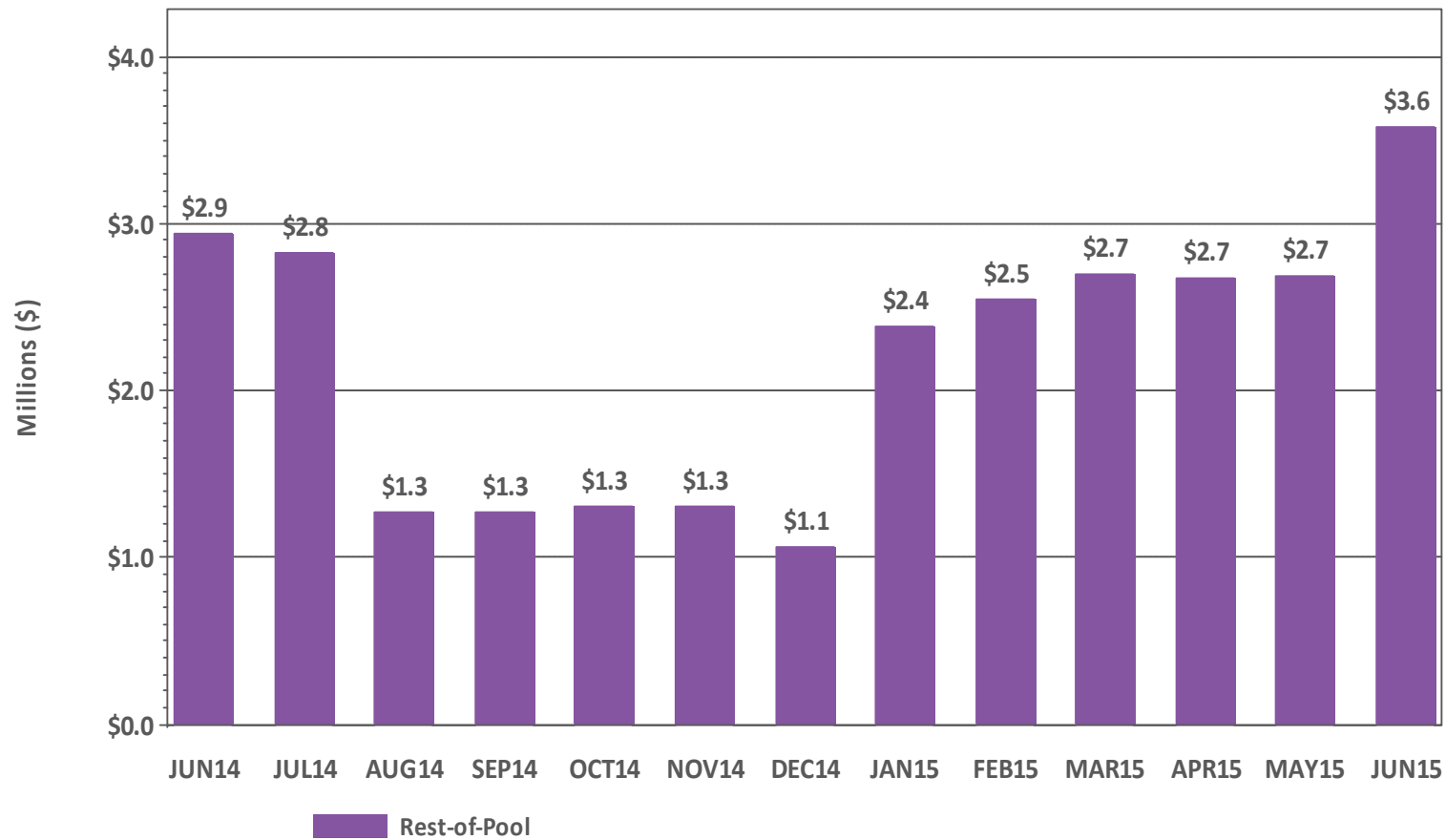


Rest-of-Pool

Rolling Average PER is currently calculated as a rolling twelve month average of individual monthly PER values for the twelve months preceding the obligation month.

Individual monthly PER values are published to the ISO web site here: [Home > Markets > Other Markets Data > Forward Capacity Market > Reports](#) and are subject to resettlement.

# PER Adjustments



PER Adjustments are reductions to Forward Capacity Market monthly payments resulting from the rolling average PER.



# Summary of Market Performance for 2014 and Q1 2015



---

*Presentation at NEPOOL PC Meeting*

**Jeff McDonald**

VICE PRESIDENT MARKET MONITORING

ISO NEW ENGLAND



# Highlights

- Wholesale electricity costs increased by approx. 12% in 2014 due to higher natural gas prices during Q1 2014
  - The average price of natural gas, which set the wholesale electricity price in 70% of the hours in 2014, rose 15% last year, from \$6.97 per million British thermal units (MMBtu) in 2013 to \$7.99/MMBtu in 2014
- “Make-whole” payments (NCPC) to suppliers increased by 10% due to the operation of expensive generation during extreme cold weather in the first quarter of 2014
- The energy market was structurally competitive with low level of concentration on average throughout the year
- Energy Market Offer Flexibility went into effect in December 2014, improving a generator’s ability to reflect in its energy offer the cost of procuring fuel for each hour of the operating day and to update the cost in real time
- FCA 8 was the first capacity auction conducted without a “floor price”. A number of administrative pricing rules were triggered, including Insufficient Competition, resulting in prices of \$15 and \$7.03/KW-month
- Rule changes were, and are currently being, developed to address market power concerns in the capacity market

# Wholesale Market Outcomes: 2014 Vs. 2013

Type	Annual Costs (\$ Billions)			Average Costs (\$/MWh)		
	2013	2014	% Change	2013	2014	% Change
Energy	7.49	8.42	12%	58.14	66.25	14%
Capacity	1.06	1.06	1%	8.20	8.36	2%
Ancillary Services	0.27	0.41	50%	2.12	3.23	52%
<b>Total</b>	<b>8.82</b>	<b>9.90</b>	<b>12%</b>	<b>68.47</b>	<b>77.84</b>	<b>14%</b>



# Wholesale Market Outcomes in 2014

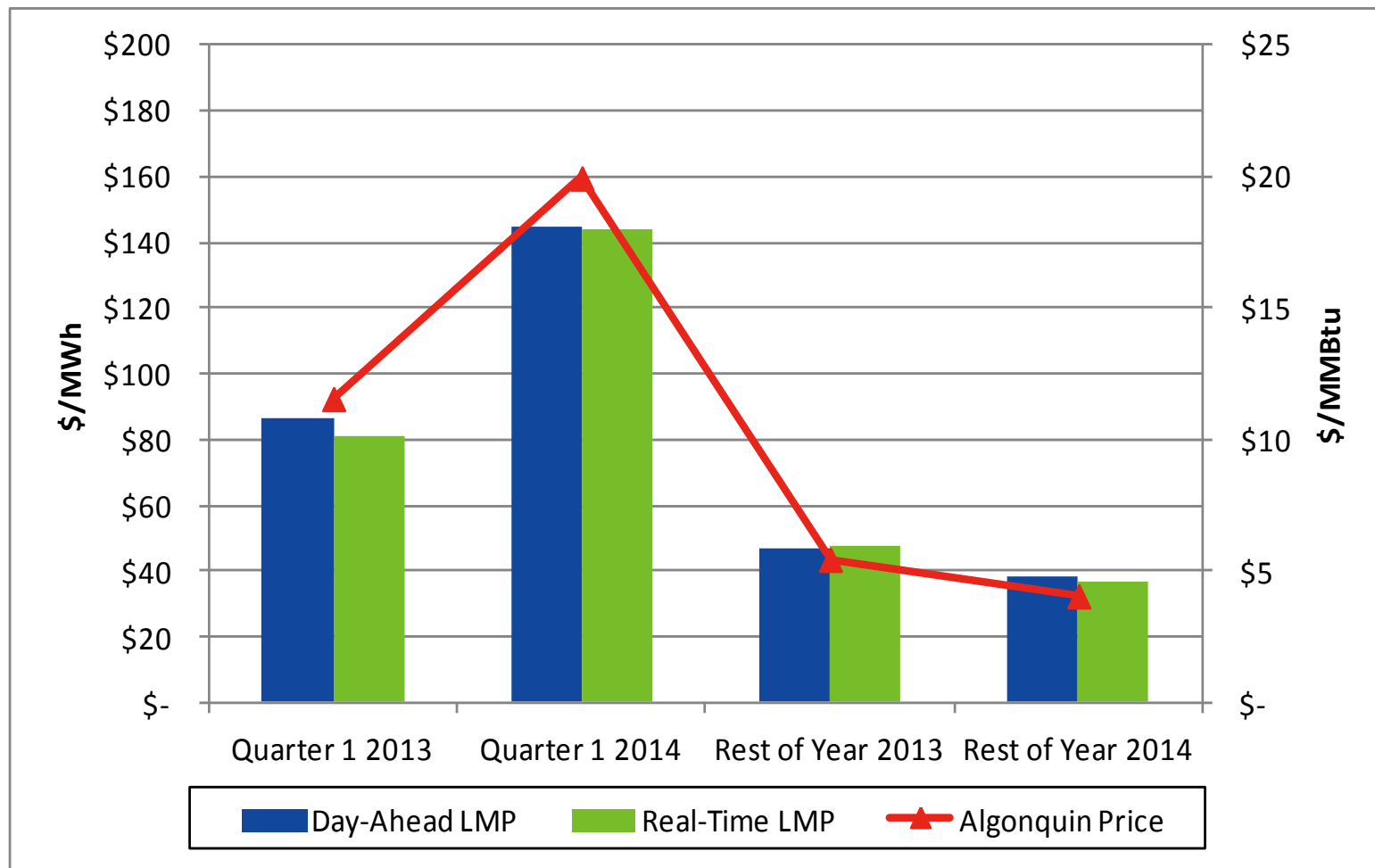
- Increase in energy costs was the result of an increase in natural gas prices, specifically in Quarter 1 of 2014
  - Relative to 2013, natural gas costs increased by 15% for the year
- The costs of procuring systemwide operating reserves through the Forward Reserve Market (FRM) increased in 2014 due, in part, to increased operating reserve requirements and change in non-performance penalty structure
- NCPC increased from \$158 million to \$174 million, the result of the operation of expensive generation during extreme cold weather in the first quarter of 2014
- Payments to suppliers providing regulation services increased in 2014 compared with 2013, the result of increased natural gas prices, as well as changes in regulation services rules implemented in July 2013
- Modest decrease in energy consumption
  - Relative to 2013, energy consumption decreased by 2%

# Key Statistics

Statistic	2013	2014	% Change 2013 to 2014
Real-time Load (GWh)	129,377	127,138	-2%
Weather-normalized real-time load (GWh)	127,754	127,114	-1%
Average day-ahead Hub LMP (\$/MWh)	56.42	64.56	14%
Average real-time Hub LMP (\$/MWh)	56.06	63.32	13%
Average natural gas price (\$/MMBtu)	6.97	7.99	15%



# Electricity Prices and Natural Gas Prices



# Market Competitiveness

- IMM tested market structure for competitiveness at the system level using a number of industry-standard methods, including:
  - C4: The amount of generation and load held by the four largest generators or load-serving entities is not large enough to raise concerns about the exercise of market power
    - 4 largest *generation participants* provided 40% of the total electricity produced for the 2014 peak hour (on July 2, 2014)
    - 4 largest *load-serving participants* served 35% of the total system load for the load hour
  - RSI: results are consistent with a structurally competitive market
    - pivotal suppliers existed during 37 hours in 2014, approximately 0.4% of all hours

# FCA 8 Auction Results

- With the withdrawal of capacity at \$14.99/kW-month all system and zonal capacity requirements were satisfied and the FCA #8 clearing price was set by an auction clearing function at \$15.00/kW-month
- Several administrative pricing rules were enacted that resulted in the following pricing by zone and new v. existing classification:

<b>Zone / Area</b>	<b>New Resources</b>	<b>Existing Resources</b>
<b>NEMA / Boston</b>	\$15.00	\$15.00
<b>Not NEMA / Boston</b>	\$15.00	\$7.025

# Results of FCA 9

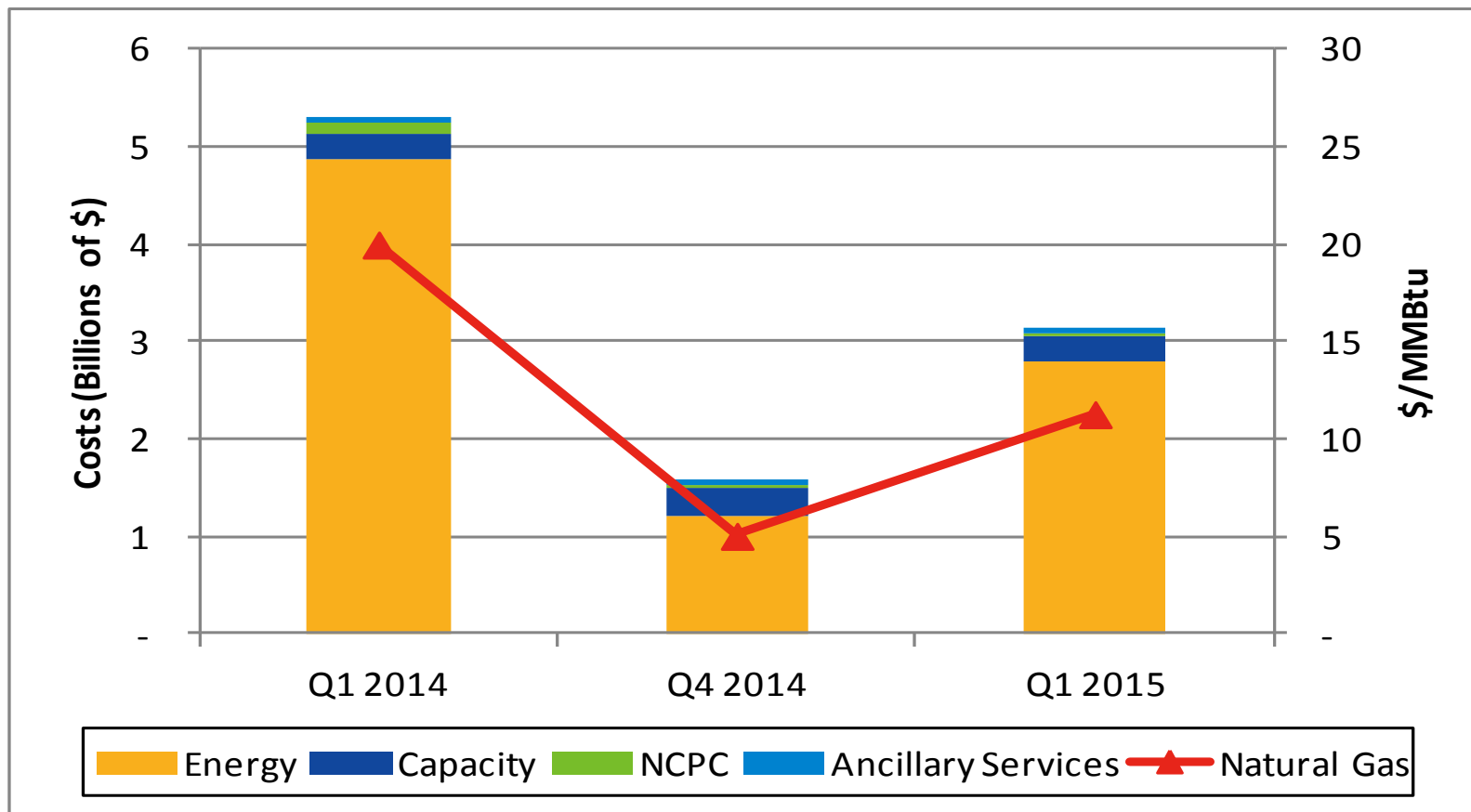
New v. Existing	Systemwide (Includes NEMA and CT)	SEMA-RI	External Interface NY AC Ties	External Interface New Brunswick
<i>New Capacity</i>	\$9.551	\$17.728	\$7.967	\$3.94
<i>Existing Capacity</i>	\$9.551	\$11.08	\$7.967	\$3.94



# Summary for Q1 2015

- Estimated wholesale market costs of \$3.14 billion, a 41% decrease compared to the same period in 2014 (Q1 2014)
- Lower natural gas and oil prices were the primary drivers for the decrease in total energy costs:
  - Natural gas prices averaged \$11.37/MMBtu, a 43% decrease from Q1 2014
  - Oil prices were 51% lower compared to Q1 2014
- NCPC payments totaled \$36 million, a 67% decrease from Q1 2014
- Since EMOF was implemented, there has been a significant increase in the frequency of the negative LMPs (occurring in 0.6% of total intervals).

# Wholesale Market Cost Summary



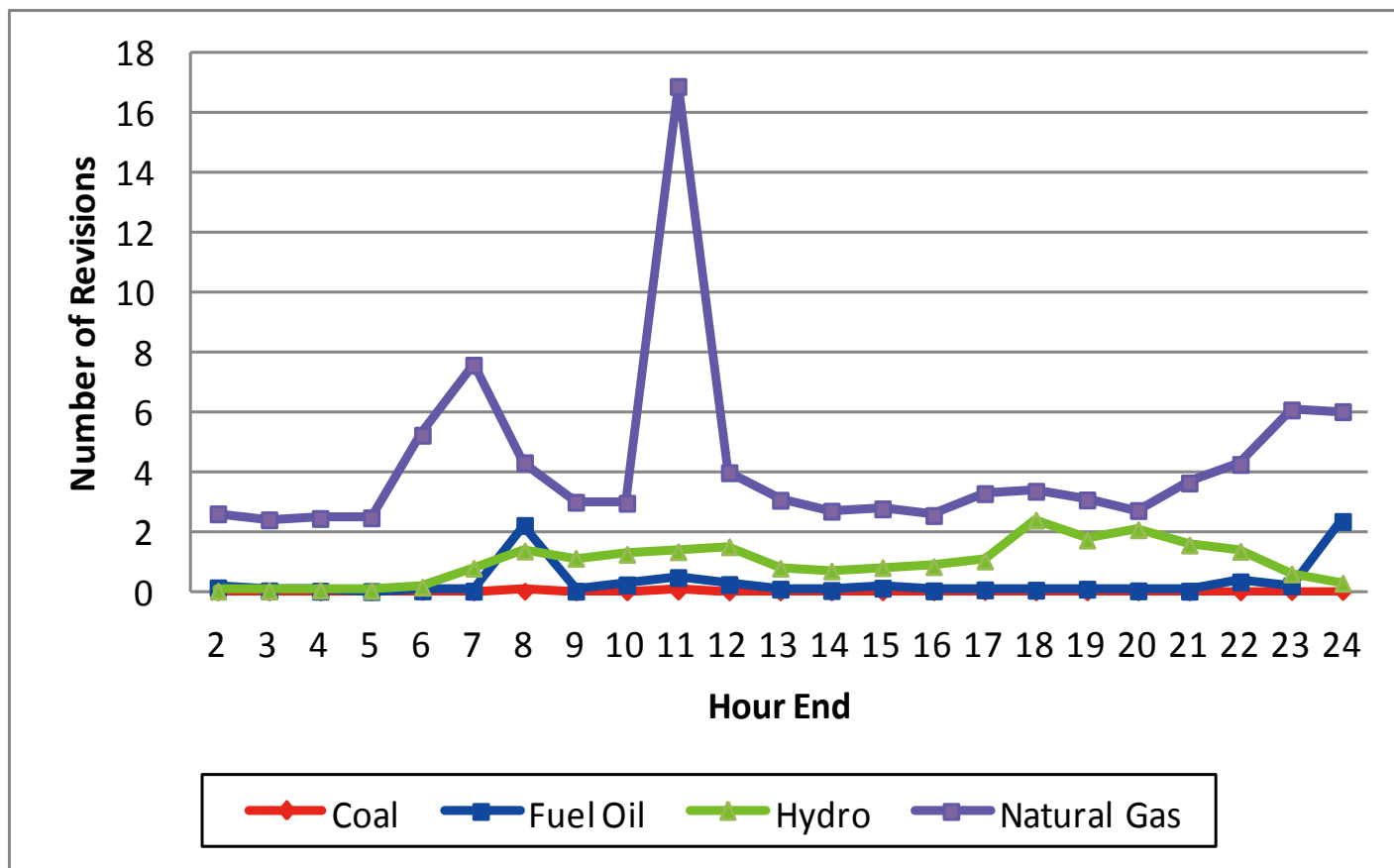
# Key Statistics

	Q1 2015	Q4 2014	Percent Change Q1 2015 to Q4 2014	Q1 2014	Percent Change Q1 2015 to Q1 2014
<b>Real-Time Load (GWh)</b>	33,578	30,604	10%	33,528	0%
<b>Weather Normalized Real-Time Load (GWh)</b>	32,440	30,664	6%	32,804	-1%
<b>Average Day-Ahead Hub LMP (\$/MWh)</b>	84.84	40.90	107%	144.99	-41%
<b>Average Real-Time Hub LMP (\$/MWh)</b>	81.97	39.27	109%	143.66	-43%
<b>Average Natural Gas Price (\$/MMBtu)</b>	11.37	5.02	126%	19.95	-43%



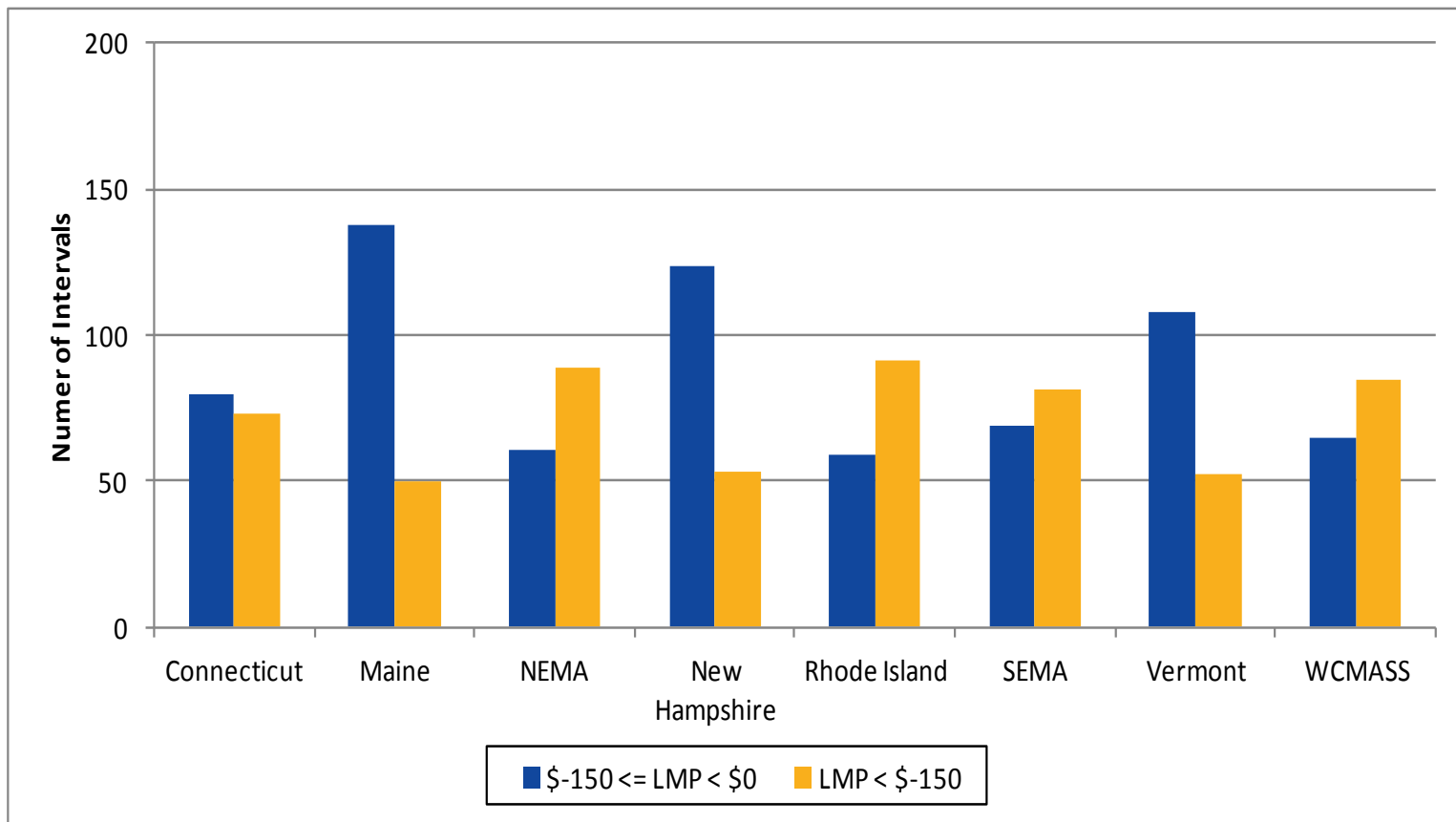
# EMOF – Utilization of Offer Flexibility

*Average number of offer block price revisions by fuel type and hour in the real-time energy market, Q1 2015 (HE02-24)*



# EMOF –Negative LMPs

*Number of 5-minute Real-Time pricing intervals with negative LMPs by load zone, Q1 2015*



# Questions





# ISO New England's Internal Market Monitor

## 2014 Annual Markets Report

© ISO New England Inc.  
Internal Market Monitor  
May 20, 2015

## Preface

The Internal Market Monitor (IMM) of ISO New England (ISO) publishes an Annual Markets Report (AMR) that assesses the state of competition in the wholesale electricity markets operated by the ISO.<sup>1</sup> The *2014 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2014. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of *Market Rule 1*, Section III.A.17.2.4, Appendix A, *Market Monitoring, Reporting, and Market Power Mitigation*:

*The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, Net Commitment-Period Compensation costs and the performance of the Forward Capacity Market and Financial Transmission Rights Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.<sup>2</sup>*

This report is being submitted simultaneously to the ISO and the US Federal Energy Regulatory Commission (FERC) per FERC order:

*The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of a Regional Transmission Organization's market monitor at the same time they are submitted to the RTO.<sup>3</sup>*

The External Market Monitor (EMM) also publishes an annual assessment of the ISO New England wholesale electricity markets. The EMM is external to the ISO and reports directly to ISO New England's board of directors. Like the IMM's report, the External Market Monitor's report assesses the design and operation of the markets and the competitive conduct of the market participants.

This report presents the most important findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2014. Section 1 summarizes the

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<sup>1</sup> Capitalized terms used but not defined in this report are intended to have the meanings given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff ("ISO Tariff") or in ISO operating procedures. The ISO Tariff is available at [www.iso-ne.com/regulatory/tariff/index.html](http://www.iso-ne.com/regulatory/tariff/index.html). Market Rule 1 is Section III of the ISO Tariff.

<sup>2</sup> *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section III.A.17.2.4, *Market Rule 1*, Appendix A, "Market Monitoring, Reporting, and Market Power Mitigation" (December 3, 2014), [http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect\\_3/mr1\\_append\\_a.pdf](http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf).

<sup>3</sup> FERC, PJM Interconnection, L.L.C. et al., *Order Provisionally Granting RTO Status*, Docket No. RT01-2-000, 96 FERC ¶ 61,061 (July 12, 2001).

region's wholesale electricity market outcomes for 2014, the important market issues and our recommendations for addressing these issues, the overall competitiveness of the markets, and market mitigation and market reform activities. Section 2 and Section 3 include more detailed discussions of each of the markets, market results, analysis and recommendations. Section 4 provides information on audits conducted to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders. A list of acronyms and abbreviations also is included. Key terms are italicized and defined within the text and footnotes.

All information and data presented are the most recent as of the time of publication. Some data presented in this report are subject to resettlement. Underlying natural gas data is furnished by the Intercontinental Exchange (ICE):



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# Section 1

## Executive Summary

The *2014 Annual Markets Report* addresses the development, operation, and performance of the wholesale electricity markets administered by ISO New England (ISO) and presents an assessment of each market based on market data and performance criteria. In addition to buying and selling wholesale electric energy in the day ahead and in real time, the participants in the ISO-administered forward and real-time markets buy and sell operating reserve products, regulation service, Financial Transmission Rights (FTRs), and capacity. These markets ensure the competitive and efficient supply of electricity to meet the energy needs of the New England region and secure adequate resources required for the reliable operation of the power system.

This section summarizes the region's wholesale electricity market outcomes for 2014, the important market issues and recommendations for addressing these issues, the overall competitiveness of the markets, and market mitigation and market reform activities. Section 2 and Section 3 contain a more detailed discussion of the performance of the real-time and forward markets, respectively. A list of abbreviations and acronyms is included at the end of the report. Key terms are italicized and defined within the text and footnotes.

### 1.1 Summary of Market Outcomes

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Over the long run, competitive and efficient wholesale electricity and capacity markets provide the incentives to maintain an adequate supply of electric energy at prices consistent with the cost of providing it. The core responsibilities of the ISO New England Internal Market Monitor include reviewing the competitiveness of the wholesale electricity markets, reporting on the performance of the markets, and recommending improvements to the market design. In this report market outcomes and associated information for 2014 are reviewed, and we conclude that the wholesale electric markets operated competitively in 2014. Energy prices remain at levels consistent with short-run marginal production costs. Market concentration, based on the number of companies selling electricity in the market and their respective shares of the total production, remained at a competitive level. The weather in 2014 was milder compared with 2013; however, the region experienced significant increases in fuel prices in the first quarter of 2014, which was the primary driver of an increase in energy prices from 2013 to 2014. See Table 1-1.

**Table 1-1**  
**Key Statistics on Load, Locational Marginal Prices (LMPs), and Input Fuels**

Statistic <sup>(a)</sup>	2013	2014	% Change 2013 to 2014
Real-time Load (GWh)	129,377	127,138	-2%
Weather-normalized real-time load (GWh)	127,754	127,114	-1%
Peak real-time load (MW)	27,379	24,443	-11%
Average day-ahead Hub LMP (\$/MWh)	56.42	64.56	14%
Average real-time Hub LMP (\$/MWh)	56.06	63.32	13%
Average natural gas price (\$/MMBtu)	6.97	7.99	15%

(a) GWh and MWh stand for *gigawatt-hours* and *megawatt-hours*, respectively; MW stands for *megawatts*; and MMBtu stands for *million British thermal units*. The *Hub* is a collection of energy pricing locations that has a price intended to represent an uncongested price for electric energy, facilitate energy trading, and enhance transparency and liquidity in the marketplace. *Weather-normalized* results are those that would have been observed if the weather were the same as the long-term average.

Table 1-2 shows estimated wholesale electricity costs (in dollars and dollars per megawatt-hour; \$/MWh) broken down by market product (i.e., energy, capacity, etc.) in 2014 compared with 2013. Total costs of wholesale electricity increased by about 12%.<sup>4</sup> Some of the factors contributing to the 12% increase are as follows:

- Prices for natural gas, the predominant fuel used to produce electricity in New England, increased in 2014, causing overall energy prices to increase compared with the prior year. Section 1.1.1 and Section 2.1.3.3 contain more information on the relationship between natural gas and electricity prices and the challenges resulting from New England's dependency on natural gas.
- The costs of procuring systemwide operating reserves through the Forward Reserve Market (FRM) increased in 2014 due, in part, to increased operating reserve requirements. More information on the FRM, the types of operating reserve products, and FRM requirements is included in Section 3.3.
- Additional "make-whole" payments to suppliers for costs that could not be recovered through energy market payments, also known as Net Commitment-Period Compensation (NCPC), increased in 2014. The increase resulted from the operation of expensive generation during extreme cold weather in the first quarter of 2014 (see Section 2.1.4).

<sup>4</sup> The annual total cost of electric energy is approximated as the product of the annual real-time load obligation for the region and the average annual real-time LMP. The real-time load obligation is the requirement that each market participant has for providing electric energy at each location (i.e., pricing node, load zone, or the Hub) equal to the amount of load it is serving, including external and internal bilateral transactions. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of annual wholesale costs.

- Payments to suppliers providing regulation services increased in 2014 compared with 2013. The increase was the result of increased natural gas prices, as well as changes in regulation services rules implemented in July 2013 (see Section 2.3).

**Table 1-2**  
**Wholesale Market Cost Summary**

Type	Annual Costs (\$ Billions)			Average Costs (\$/MWh) <sup>5</sup>		
	2013	2014	% Change	2013	2014	% Change
Energy	7.49	8.42	12%	58.14	66.25	14%
Capacity	1.06	1.06	1%	8.20	8.36	2%
Ancillary Services <sup>6</sup>	0.27	0.41	50%	2.12	3.23	52%
<b>Total</b>	<b>8.82</b>	<b>9.90</b>	<b>12%</b>	<b>68.47</b>	<b>77.84</b>	<b>14%</b>

### 1.1.1 Natural Gas Dependency and Energy Market Enhancements

New England's wholesale electricity market is highly dependent on the availability of natural gas and fuel oil. A number of market forces influence the relationship of the New England electricity market and the natural gas market, including the following:

- An influx of natural gas-fired generating capacity over the past 15 years<sup>7</sup>
- An aging and declining fleet of oil- and coal-fired generators, many of which were constructed during the 1960s and 1970s, and the retirement of the Vermont Yankee nuclear station. These generators are increasingly being displaced by more efficient gas-fired generators
- Lower natural gas prices resulting from increased production of domestic shale gas from the Marcellus Shale region of the country
- Relatively static gas pipeline capacity in New England that has had to accommodate a 37% increase in overall natural gas consumption in New England from 1999 through 2013; three-fourths of this 37% increase was for gas generation.<sup>8</sup>

<sup>5</sup> The annual cost is divided by the real-time load obligation to obtain the average total price.

<sup>6</sup> Ancillary services include operating reserves, regulation, and NCPC payments.

<sup>7</sup> During the 1990s, the region's electricity was produced primarily by oil, coal, and nuclear generating plants, with very little gas-fired generation. In 1990, oil and nuclear generating plants each produced approximately 35% of the electricity consumed in New England, whereas gas-fired plants accounted for approximately 5%. Coal plants produced about 18% of New England's electricity. In contrast, by 2011, oil-fired plants produced 0.6% of electricity consumed in New England, and approximately 51% was produced by gas-fired generation. Coal production also fell by about two-thirds. ISO New England, *Addressing Gas Dependence* (July 2012), [http://www.iso-ne.com/static-assets/documents/committees/comm\\_wkgrps/strategic\\_planning\\_discussion/materials/natural\\_gas\\_white\\_paper\\_draft\\_july\\_2012.pdf](http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/natural_gas_white_paper_draft_july_2012.pdf).

<sup>8</sup> Approximately 12,000 of 14,000 MW of new capacity have come from gas-fired, combined-cycle generators. *ISO New England 2013 Regional Electricity Outlook*, p. 15 (2014), [http://www.iso-ne.com/aboutiso/fin/annl\\_reports/2000/2014\\_reo.pdf](http://www.iso-ne.com/aboutiso/fin/annl_reports/2000/2014_reo.pdf). Total consumption in New England increased by 37%; total deliveries to electric power consumers increased by 99%; and total consumption by residential, commercial, industrial, and vehicle fuel end uses increased by 1,394%. Note that these data have not been weather normalized.

One of the most pressing challenges identified in the ISO's Strategic Planning Initiative has been the region's reliance on generators fueled by natural gas.<sup>9</sup> In the *2013 Annual Markets Report* 29 instances were identified when generators fueled by natural gas were not available to produce electricity because natural gas was not available due to a constraint or limitation on the natural gas pipeline. In tandem, the ISO undertook a number of projects aimed at improving the reliability of generators fueled by oil and natural gas through improved market incentives and market design, and supplemental payments to improve fuel diversity.

For example, the 2013/2014 Winter Reliability Program provided financial incentives to oil-fired generators to maintain on-site inventories. The program also provided incentives to dual-fuel generators capable of burning oil or natural gas to test and maintain their dual-fuel capability. The 2014/2015 Winter Reliability Program, built on the prior winter program, also provided incentives for resources to enter into contracts for liquefied natural gas (LNG) and included additional market monitoring changes designed to provide greater flexibility to dual-fuel resources. By ensuring that oil- and dual-fuel-fired generators had sufficient on-site fuel inventory, and that participating gas generators contracted for liquefied natural gas, the winter reliability programs helped mitigate concerns about the reliance of generators fueled by natural gas on pipeline deliveries of fuel during periods of high natural gas demand and stress on the pipeline system.

The number of reductions in generation availability associated with the availability of natural gas declined in 2014 compared to 2013. This decrease is coincident with the Federal Energy Regulatory Commission's (FERC's) August 2013 order clarifying the obligations of resources to procure fuel, the changes in the Day-Ahead Energy Market supply-offer timeline that went into effect in mid-2013, and the implementation of Energy Market Offer Flexibility (EMOF) that went into effect in December 2014.<sup>10</sup>

The combination of market fundamentals such as the increased supply of LNG in New England in late 2014, lower oil prices, a mild summer, along with the implementation of a number of ISO initiatives had the expected outcome of increasing reliability during 2014 and lowering electric energy prices after the first quarter of 2014.

### **1.1.2 Dual-Fuel Generator Exemption from Certain Requirements to Provide Documentation**

As part of the winter reliability program package,<sup>11</sup> FERC approved an IMM proposal that dual-fuel generators be exempt from the requirement to justify and verify the use of the higher-priced fuel when oil and natural gas index prices converge—specifically, when the ratio of the

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US Energy Information Administration (EIA), "Natural Gas Consumption by End Use," webpage (data for state-level and end-user natural gas consumption, 1999–2013) (March 30, 2015), [http://www.eia.gov/dnav/ng/ng\\_cons\\_sum\\_dcu\\_SCT\\_a.htm](http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SCT_a.htm).

<sup>9</sup> More information about the ISO's Strategic Planning Initiative is available at <http://www.iso-ne.com/committees/key-projects/strategic-planning-initiative>.

<sup>10</sup> FERC, *Order on Complaint, New England Power Generators Association v. ISO New England*, Docket No. EL13- 66 - 000 (August 27, 2013), [http://www.iso-ne.com/regulatory/ferc/orders/2013/aug/el13-66-8-7-13\\_order\\_nepga\\_complaint.pdf](http://www.iso-ne.com/regulatory/ferc/orders/2013/aug/el13-66-8-7-13_order_nepga_complaint.pdf).

<sup>11</sup> ISO New England Inc. and New England Power Pool, *ISO New England Inc., Docket No. ER14-\_\_\_-000 Winter 2014-15 Reliability Program (Part 1 of 2)* (July 11, 2014), [http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14\\_2407\\_000\\_win\\_rel\\_pro\\_7\\_11\\_2014.pdf](http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14_2407_000_win_rel_pro_7_11_2014.pdf).

generator's higher-priced fuel index price to its lower-priced fuel index price is less than or equal to 1.75.<sup>12</sup>

FERC required that the appropriateness of the ratio be reviewed and that the analysis and recommendations be provided as part of the Annual Markets Report. The analysis described in Section 2.1.4.4 shows that, notwithstanding the reduction in natural gas price volatility during winter 2014/2015, the 1.75 ratio continues to be a reasonable and appropriate indicator of oil and natural gas price convergence and consequently should remain as the exemption threshold.

### 1.1.3 Forward Capacity Market

The ISO held the eighth Forward Capacity Auction (FCA #8) on February 3, 2014. Unlike the seven previous auctions, FCA #8 was the first auction conducted without a "floor price." With one limited exception, the seven previous auctions all cleared at the administratively set floor prices with excess capacity.<sup>13</sup>

Before FCA #8 was conducted, 3,135 MW of existing resources announced plans to retire. This resulted in an insufficient number of resources participating in the auction to ensure a competitive outcome. The insufficient competition triggered the FCM's administrative pricing rules designed to mitigate any market power, which could inappropriately raise prices, while still providing incentives to attract and retain resources. The Carry Forward rule also applied in NEMA/Boston Carry Forward due to excess procurement in the prior auction.

FCA #8 resulted in the acquisition of 33,712 MW of capacity supply obligations in 2017/2018, which was 143 MW short of the 33,855 MW procurement target. Under the administrative pricing rules, the capacity clearing price of \$15.00/kilowatt (kW)-month will be paid in 2017/2018 to about 1,380 MW of new capacity resources outside the Northeast Massachusetts/Boston (NEMA/Boston) zone. About 24,885 MW of existing resources will be paid \$7.025/kW-month. Self-supply resources, totaling 3,330 MW, will not receive any payment through the FCM.

Another 357 MW of existing resources with multiyear supply obligations will be paid at rates set in previous auctions, ranging from \$2.52/kW-month to \$3.43/kW-month. In NEMA/Boston, 3,085 MW of both new and existing resources will be paid \$15.00/kW-month based on administrative pricing rules, while 674 MW of existing capacity that opted for a multiyear price commitment in a previous auction will be paid \$14.99/kW-month.

While the auction closed with slightly less capacity than expected to be needed in 2017/2018, the FCM design provides a mechanism for such gaps to be closed through annual and monthly reconfiguration auctions held over the three years before the capacity commitment period.

In its review of FCA #8, FERC determined that the current FCM rules may create an opportunity for suppliers importing capacity from outside New England to exercise market power and may result in preferential or unduly discriminatory treatment favoring importers over other capacity resources. As a result, FERC required the ISO to revise the FCM rules to require the

<sup>12</sup> For example, if the day-ahead index price of natural gas is \$5/MMBtu and the day-ahead index price of No. 2 oil is \$20/MMBtu the ratio would be calculated as \$20 divided by \$5, or 4.0. On the other hand, if the day-ahead index price of natural gas is \$30/MMBtu and the day-ahead index price of No. 2 oil is \$20/MMBtu, the ratio would be calculated as \$30 divided by \$20 or 1.5.

<sup>13</sup> One zone in the FCA #7 cleared above the floor price.

IMM to review importer capacity offers before each FCA and to treat them in a manner similar to other existing capacity resources for mitigating the exercise of market power. These rules were implemented in time for their use in FCA #9.

#### 1.1.4 Ancillary Service Markets

Real-time operating reserve payments declined from \$54.0 million in 2013 to \$38.6 million in 2014. Except for payments to some resources in NEMA/Boston (which only increased modestly), operating reserve payments decreased across all products and regions. Payments to resources providing regulation service totaled \$28.8 million in 2014, a 41% increase from 2013. Changes to the methodology for calculating regulation service payments, required under FERC Order No. 755, and increased natural gas prices, contributed to the increased cost of regulation service.<sup>14</sup>

## 1.2 Market Design Changes

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The following is a summary of the major revisions to the market design implemented in 2014 and planned for in future years:

### 1.2.1 Major Design Changes Implemented in 2014

Three major changes to the market design have been implemented in 2014.

#### 1.2.1.1 Energy Market Offer Flexibility

The ISO implemented Energy Market Offer Flexibility changes on December 3, 2014.<sup>15</sup> The changes are designed to improve a market participant's ability to reflect expected fuel costs in its energy market supply offers, and to update its offers as expected fuel costs change during the operating day. Offers that more accurately reflect expected fuel costs improve energy market price signals.

The EMOF changes provide market participants with the following flexibility:

- The ability to change their supply offers during the operating day to reflect the costs of purchasing intraday fuel. This is a significant improvement for the owners of generators fueled by natural gas because it allows them to reflect expected natural gas price volatility in their supply offers
- The ability to submit certain supply offer parameters that vary by hour, rather than requiring the parameters to be the same for all hours of an operating day
- The ability to submit a negative supply offer as low as negative \$150/MWh

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<sup>14</sup> ISO New England Inc. and New England Power Pool, *Regulation Market Opportunity Cost Change*, Docket No. ER13-1259-000, FERC filing (filed April 11, 2013), [http://www.iso-ne.com/regulatory/ferc/filings/2013/apr/er13-1259-000\\_4-11-2013\\_reg\\_mkt\\_opp\\_cost\\_chg.pdf](http://www.iso-ne.com/regulatory/ferc/filings/2013/apr/er13-1259-000_4-11-2013_reg_mkt_opp_cost_chg.pdf). FERC, letter order accepting the opportunity cost changes (June 27, 2013), [http://www.iso-ne.com/regulatory/ferc/orders/2013/jun/er13-1259-000\\_6-17-13\\_ltr\\_order\\_accept\\_reg\\_mrkt\\_rev.pdf](http://www.iso-ne.com/regulatory/ferc/orders/2013/jun/er13-1259-000_6-17-13_ltr_order_accept_reg_mrkt_rev.pdf).

<sup>15</sup> ISO New England Inc. and NEPOOL, *Energy Market Offer Flexibility Changes*, Docket No. ER13-1877-000, FERC filing, (July 1, 2013), [http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/jul/er13\\_1877\\_000\\_mkt\\_offer\\_flex\\_7\\_1\\_2013.pdf](http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/jul/er13_1877_000_mkt_offer_flex_7_1_2013.pdf). FERC, *Order Conditionally Accepting Tariff Revisions*, Docket No. ER13-1877-000 (October 3, 2013), [http://www.iso-ne.com/regulatory/ferc/orders/2013/oct/er13-1877-000\\_10-3-13\\_order\\_condition\\_accept\\_flex\\_rev.pdf](http://www.iso-ne.com/regulatory/ferc/orders/2013/oct/er13-1877-000_10-3-13_order_condition_accept_flex_rev.pdf).

#### 1.2.1.2 Increasing (Operating) Reserve Constraint Penalty Factors

In response to a FERC order, the ISO increased the Reserve Constraint Penalty Factors (RCPFs).<sup>16</sup> The RCPFs are administratively set limits on redispatch costs (\$/MWh) that the system will incur to meet operating reserve constraints and that will become the reserve price when operating reserves are scarce. The RCPFs for 30-minute operating reserves increased from \$500/MWh to \$1,000/MWh, and 10-minute non-spinning reserves increased from \$850/MWh to \$1,500/MWh. This change was implemented on December 3, 2014.

#### 1.2.1.3 Review and Mitigation of New Import Capacity Resources in the FCM

Under the previous market rule, most new import capacity resources were not subject to a cost review for market power. Consequently, a supplier with a new import capacity resource was free to remain in the auction at any price above zero and was thereby exempt from buyer-side market power mitigation.<sup>17</sup> Further, even though most new import capacity resources were sponsored by suppliers who are essentially renewing their import contracts year after year, these resources were not subject to the same type of seller-side market power mitigation as existing capacity resources. Therefore, a supplier with a new import capacity resource was free to exit the auction at any price. The supplier with a new import capacity resource could exercise either buyer-side or seller-side market power by taking uneconomic actions during the auction.

In an October 16, 2014 filing, rule revisions were filed to provide for the review and potential mitigation of importers' supply offers before each annual Forward Capacity Auction.<sup>18</sup> The rule revisions determine which import suppliers have market power (that is, which are "pivotal") and apply mitigation to those suppliers in a manner consistent with the mitigation applied to existing resources located within New England.

#### 1.2.1.4 FCM Pay-for-Performance Market Design

The pay-for-performance (PFP) design is based on the two-settlement logic generally used in forward markets. It entails two key elements. The first element is a forward position in which a quantity of capacity is obligated, or sold, in the capacity auction. Each megawatt is paid at the auction clearing price, and the sale creates a resource-specific physical obligation and forward financial position in the capacity market. A resource's forward financial position is a share of the system's energy and reserve requirements during operating reserve deficiencies.

The second element includes a settlement for deviations. A resource that delivers more than its share of the system's requirements during an operating reserve deficiency (i.e., an over-performer) will be paid for that incremental production. If it delivers less than its share (i.e., it underperforms), it will "buy out" of its position by paying other resources that did deliver. Positive and negative deviations are paid or charged at the same rate specified in the tariff.

<sup>16</sup> FERC, *Order on Compliance Filing* (October 2, 2014), [http://www.iso-ne.com/static-assets/documents/2014/10/er14-2419-000\\_-001\\_10-2-14\\_pay\\_for\\_performance\\_compliance\\_order.pdf](http://www.iso-ne.com/static-assets/documents/2014/10/er14-2419-000_-001_10-2-14_pay_for_performance_compliance_order.pdf).

<sup>17</sup> In the context of this discussion, buyer-side market power is exercised through a participant offering supply at a price below cost to lower the auction price and benefit the participant's net buy position. Conversely, seller-side market power can be exercised by a participant offering supply at a price above cost to increase the auction price and benefit the participant's net sell position.

<sup>18</sup> *ISO New England, Inc., Docket EL14-99-000, Response to Order to Show Cause*, FERC filing (October 16, 2014), [http://www.iso-ne.com/static-assets/documents/2014/10/er15-117-000\\_show\\_cause\\_10-16-2014.pdf](http://www.iso-ne.com/static-assets/documents/2014/10/er15-117-000_show_cause_10-16-2014.pdf).

The two-settlement approach is standard in forward contracts, both for electricity and commodities, ranging from oil to agricultural goods to metals. In fact, the two-settlement design underlies the design of New England's day-ahead and real-time electricity markets (in which deviations are settled at the real-time price) and is well understood by stakeholders.

Under PFP, buyers will pay the auction-clearing price to all resources that clear in the Forward Capacity Auction. Because over-performers will be paid by the under-performers, buyers will not bear the short-run risk of covering any unexpectedly high performance payments. This will continue to provide buyers with a predictable capacity price three years after the close of each Forward Capacity Auction. Having under-performers pay over-performers will also provide strong incentives for each resource to perform as needed and for over-performers to benefit by helping meet the system's needs. These incentives will place performance risk on all FCM resources, and each resource will need to price this risk in its future capacity auction bids. The first element of the PFP two-settlement contract was implemented with the ninth FCA in February, 2015, and the second element of the two-settlement construct will become fully effective during the associated capacity commitment period beginning June 1, 2018.

#### *1.2.1.5 FCM Sloped Demand Curve*

In its May 30, 2014 Order, the FERC accepted the ISO's proposal to implement a system-wide sloped demand curve for the FCM.<sup>19</sup> The ISO implemented the sloped demand curve at the system level for the ninth FCA. Continuing issues regarding the potential for market power to be exercised within capacity zones have been identified, specifically within import-constrained capacity zones, and we are addressing these issues with the ISO and stakeholders in conjunction with the development of zonal demand curves.<sup>20</sup>

### **1.2.2 Major Design Changes Proposed for Future Years**

The following major design changes to the market design have been proposed for future delivery years.

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<sup>19</sup> FERC, *ISO New England Inc. and New England Power Pool Participants Committee, Order Accepting Tariff Revisions*, Docket No. ER14-1639-000, 147 FERC ¶ 61,173 (2014) (the "May 30, 2014, Order"), [http://www.iso-ne.com/static-assets/documents/regulatory/ferc/orders/2014/may/er14\\_1639\\_000\\_5\\_30\\_14\\_sloped\\_demand\\_curve\\_order.pdf](http://www.iso-ne.com/static-assets/documents/regulatory/ferc/orders/2014/may/er14_1639_000_5_30_14_sloped_demand_curve_order.pdf).

<sup>20</sup> Four capacity zones were modeled in FCA #9. Three are import-constrained, and the fourth is the "Rest of Pool" zone that represents the balance of the system requirements beyond those reflected in the three import-constrained zones.

### 1.2.2.1 Uneconomic Retirements

The owners of existing generators can potentially exercise market power in an import-constrained zone through the uneconomic retirement of an existing resource.<sup>21</sup> When existing and new supply are not abundant in a capacity zone, an incumbent supplier can seek to retire an existing resource to reduce available supply. This action will have a price-increasing effect within that capacity zone, which will benefit the remainder of the supplier's portfolio in that capacity zone. In cases where capacity zones are sufficiently small, the retirement of even a single resource of moderate size can have a significant price impact even with sloped zonal demand curves.

Market rule changes are being recommended that will provide a process for reviewing options for capacity market participation or retirement, and market power mitigation measures in the capacity auction. The proposed process, with these components, eliminates the potential that a capacity auction will be executed with known market power resident through early resource retirement. It will also provide a means for resources to retire through the market, as opposed to administratively as is now the case, and potentially be replaced by new generation in that same capacity auction. The External Market Monitor has also recommended that the ISO adopt a measure that addresses the potential for retirement delist bids to be used to increase FCA prices above competitive levels.<sup>22</sup>

### 1.2.2.2 Accuracy of Static Delist Bids

The ability to modify or withdraw Static De-List Bids after the IMM's review of the bid is complete is contrary to the original intent to allow suppliers the opportunity to "fine tune" bids. The flexibility to modify or withdraw Static De-List Bids can be used more as an instrument to increase the range of acceptable bids. This permits the unintended consequence of static delist bids being submitted at prices notably higher than those representative of the resource's costs and reasonable levels of expected performance. The ability to convert a delist bid into a nonprice retirement request may also cause abrupt shifts in the supply curve at a time in the FCM annual process when no competitive market response can occur.

On May 1, 2015, market rule changes that address the potential exercise of market power in the Forward Capacity Market were filed at FERC. The first two parts of the market rule changes address with the treatment of de-list bids. First, we proposed to increase the Dynamic De-List Bid Threshold from \$3.94 to \$5.50/kW-month. This change was intended to avoid the review of de-list bid information at prices below the competitive offer price of higher cost existing resources that are expected to set the price if no new entry is needed. Second, it was proposed to limit the amount of flexibility that currently is afforded to capacity suppliers to modify Static De-List Bids after those bids have been submitted and reviewed by the IMM and also to eliminate the option to replace a Static De-List Bid with a Non-Price Retirement Request in certain instances.

These changes are intended to encourage the submission of Static De-List Bids that are closer to actual cost and remove any incentive for capacity suppliers to use the Static De-List Bid process

<sup>21</sup> Uneconomic retirement is the premature withdrawal of a generation resource's capacity from the capacity market if expectations over its remaining life indicate that continued operation of the resource would be economically viable.

<sup>22</sup> Potomac Economics, *2013 Assessment of the ISO New England Electricity Markets*, June 25, 2014, [http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind\\_mkt\\_advsvr/isone\\_2013\\_emm\\_report\\_final\\_6\\_25\\_2014.pdf](http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsvr/isone_2013_emm_report_final_6_25_2014.pdf).

to explore whether the IMM will allow bid prices that substantially exceed costs. Together, these two changes are motivated by the desire to maintain the continued integrity of the market power mitigation structure in the capacity market and to focus more closely on those bids that actually raise significant market power concerns.

#### *1.2.2.3 Improved Competitiveness Test for Existing Resources in the FCM*

The May 1, 2015 filing also included changes to improve the accuracy of the competitiveness test, or pivotal supplier test that is administered prior to the auction to determine if a capacity supplier has the potential to exercise market power. The proposed market rule establishes a single pivotal supplier test that applies to both capacity imports and existing resources. The improvements include a consistent treatment of interface constraints for purposes of determining whether a supplier is pivotal, moving the performance of the test closer to the time of the auction and a new definition of “control” that will more accurately account for resources should to be included in the assessment of a supplier’s overall capacity portfolio.

Along with the changes to the pivotal supplier test, the ISO also filed changes to improve the rules governing the treatment of import capacity resources in the Forward Capacity Auction. The proposed changes will ensure that capacity imports that are more akin to existing resources receive the same mitigation treatment in the Forward Capacity Auction as existing resources. The changes also will ensure that capacity imports that are akin to new resources receive the same treatment as other new resources during the conduct of the auction.

### **1.3 Recommendation**

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The following recommendation for improving the market design is as follows. The recommendation is based on observations of participant behavior and market outcomes in 2014 and the analysis described in the following sections of this report:

The overall decline of cleared virtual transactions in the long run continues to imply that the effects of high and uncertain transaction costs observed continue to persist, as documented in past Annual Markets Reports.<sup>23</sup> The ISO should revise the market rules so that real-time NCPC charges do not prevent virtual transactions from improving the liquidity in the day-ahead market.

In 2014, the ISO proposed market rule changes to strengthen the incentive for load serving entities, exporters and virtual demand bidders to buy energy in the day-ahead energy market. The proposed rule changes would have excluded positive load deviations from real-time first contingency NCPC charges. However, stakeholders did not support the proposed change and the ISO opted not to file the proposed change with FERC. Had the proposal been implemented, it would have addressed only *half* of the recommendation by exempting virtual demand bids from real-time NCPC charges. The proposal would not have addressed the recommendation for virtual supply offers. As noted below, the ISO plans to commence a stakeholder process in 2015 to address the NCPC cost allocation issues in general including the method used to allocate first-contingency NCPC charges to both virtual demand and supply deviations (See Section 3.1.4.).

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<sup>23</sup> A decrement bid is a bid to purchase energy at a specified location in the Day-Ahead Energy Market that is not associated with a physical load. An accepted decrement bid results in scheduled load at the specified location in the Day-Ahead Energy Market.

#### 1.4 Status of IMM Recommendations from the *2013 Annual Markets Report*

The status of the IMM recommendations from the *2013 Annual Markets Report* is shown in Table 1-3.

**Table 1-3**  
**Status of Key Recommendations from the *2013 Annual Markets Report***

2013 Recommendations	Status as of the AMR14 Publication Date
Recommendation to modify the market rules as necessary when EMOF is introduced to ensure that the use of the limited-energy generator (LEG) provisions in both the day-ahead and real-time markets are restricted to instances when the availability of fuel is physically limited.	The ISO is currently assessing this issue
Recommendation that the ISO discontinue or replace the locational marginal price calculator for calculating real-time prices.	Tariff revisions filed mid-March for implementation by June 1
Recommendation that the ISO revise the market rules so that real-time NCPC charges do not prevent virtual transactions from improving the liquidity in the day-ahead market.	Stakeholder process expected to start at the end of 2015
Recommendation that, as part of the market development plan, the ISO study, develop, and implement a market-based reliability commitment method to improve incentives for meeting reliability objectives and the efficiency of the Day-Ahead Energy Market and Real-Time Energy Market.	The ISO is currently assessing this issue

## Section 2

### Real-Time Markets

The ISO New England's (ISO's) real-time markets include the Real-Time Energy Market, the Regulation Market, and real-time operating reserves. This section describes the 2014 outcomes of the real-time markets. The section also summarizes the ISO's actions to ensure real-time reliability and includes an assessment of ISO operations.

#### 2.1 Real-Time Energy Market

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This section describes the outcomes, structure, and competitiveness of the Real-Time Energy Market. The review of market outcomes shows that the Real-Time Energy Market was competitive in 2014.

The Real-Time Energy Market is the physical market in which generators sell, and load-serving entities (LSEs) purchase, electricity. The ISO coordinates the production of electricity to ensure that the amount produced moment to moment equals the amount consumed, while respecting transmission constraints. The ISO publishes locational marginal prices (LMPs) every five minutes for each location on the transmission system at which power is either withdrawn or injected.<sup>24</sup> The prices for each location reflect the cost of the resource needed to meet the next increment of load at that location.

The Real-Time Energy Market settles the difference between positions cleared in the Day-Ahead Energy Market (discussed in Section 3.1) and actual production or consumption in the Real-Time Energy Market. Participants that consume more or provide less than their day-ahead schedule pay the real-time LMP, and participants that consume less or provide more than their day-ahead schedule are paid the real-time LMP. Because of the dependencies between the Real-Time Energy Market, the Day-Ahead Energy Market, and other forward markets, this section contains information on forward markets where relevant.

##### 2.1.1 Prices

Real-time price data for 2014 and comparisons of real-time prices and day-ahead prices are presented below (see Section 3.1.1 for a full discussion of day-ahead pricing).

###### 2.1.1.1 Real-Time Prices

In 2014, the average real-time Hub price was \$63.32/MWh, up approximately 13% from \$56.06/MWh in 2013.<sup>25</sup> This price is consistent with observed market conditions, including those for input fuel costs, loads, and generating resource operations. Price differences between the load zones primarily were due to marginal losses.<sup>26</sup> Congestion between zones can also

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<sup>24</sup> The Hub, load zones, and internal network nodes are points on the New England transmission system at which LMPs are calculated. *Internal nodes* are individual pricing points (*pnodes*) on the system. *Load zones* are aggregations of internal nodes within specific geographic areas. The *Hub* is a collection of internal nodes not typically congested. An *external interface node* is a proxy location used for establishing an LMP for electric energy received by market participants from, or delivered by market participants to, a neighboring balancing authority area.

<sup>25</sup> Throughout this report, average prices are calculated using a simple average method.

<sup>26</sup> The loss component of the LMP is the marginal cost of additional losses resulting from supplying an increment of load at the location. New England is divided into the following eight load zones used for wholesale market billing:

result in price differences, although there was little congestion between zones. Most of the congestion was the result of sub-zonal transient load pockets caused by transmission or generation elements being out of service.<sup>27</sup>

The Maine (ME) load zone continues to have the lowest average prices in the region, while the Southeastern Massachusetts (SEMA) load zone had the highest. The average LMPs in the Maine load zone were \$4.28/MWh lower than the Hub price, explained by both the marginal loss and congestion components of Maine's average LMPs. The higher NEMA prices are attributable to local area constraints within the zone. The average LMPs in the NEMA load zone were \$0.71/MWh greater than the average Hub price, again explained by both marginal loss and congestion within the NEMA zone. See Table 2-1.

**Table 2-1**  
**Simple Average Real-Time Hub and Load Zone Prices for 2013 and 2014 (\$/MWh)**

Location/Load Zone	2013	2014
Hub	56.06	63.32
Maine (ME)	53.23	59.04
New Hampshire (NH)	55.15	61.47
Vermont (VT)	55.08	61.60
Connecticut (CT)	55.89	63.11
Rhode Island (RI)	56.10	63.33
Southeast Massachusetts (SEMA)	56.43	63.44
Western Central Massachusetts (WCMA)	56.12	63.29
Northeast Massachusetts (NEMA)	56.31	64.03

#### 2.1.1.2 Day-Ahead and Real-Time Price Comparison

In 2014, average day-ahead prices at the Hub (\$64.57/MWh) were 2% more than average real-time energy prices at the Hub (\$63.32/MWh). See Table 2-2.

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Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA).

<sup>27</sup> *Load pockets* are areas of the system that require local generation to meet demand because the transfer capability of the transmission system is insufficient to serve the load in the area.

**Table 2-2**  
**2014 Annual and Quarterly**  
**Day-Ahead and Real-Time Hub Prices (\$/MWh)**

	Annual	Q1	Q2	Q3	Q4
<b>Day-ahead</b>	64.57	144.99	39.92	33.98	40.90
<b>Real-time</b>	63.32	143.66	38.16	33.70	39.27

In 2014, hourly real-time and day-ahead prices at the Hub correlated positively (0.85). Hourly real-time LMPs at the Hub for 2014 had a standard deviation of \$72/MWh, while hourly day-ahead LMPs at the Hub for 2014 had a standard deviation of \$63.64. Some factors not present in the day-ahead market affect real-time prices. Examples include contingencies or forced outages, Minimum Generation (Min Gen) Emergencies, operating reserve-shortage pricing, and ramping constraints associated with a five-minute dispatch in real time as opposed to an hourly dispatch in the day-ahead.<sup>28</sup> These factors can create additional variability in real-time prices compared with those in the day-ahead market.<sup>29</sup> See Figure 2-1.

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<sup>28</sup> The declaration of a *Minimum Generation Emergency* is called when the on-line generation plus net imports comes close to exceeding system load and all generators are operating at *economic minimum* (ecomin) (i.e., the minimum amount of electric energy available from a generating resource for economic dispatch.) A Min Gen Emergency resets the economic minimums of resources down to their emergency minimums (if available) to gain additional dispatchable range. Before the Energy Market Offer Flexibility (EMOF) rules went into effect (see Section 2.1.2.4), the ecomin LMPs were administratively set to zero. With EMOF in effect, the ecomin LMPs will be set to -\$150.

<sup>29</sup> A *forced* outage is a type of unplanned outage that involves the unexpected removal from service of a generating unit, transmission facility, or other facility or portion of a facility because of an emergency failure or the discovery of a problem. A *planned* outage is the planned inoperability of a generator or transmission facility, generally to perform maintenance.

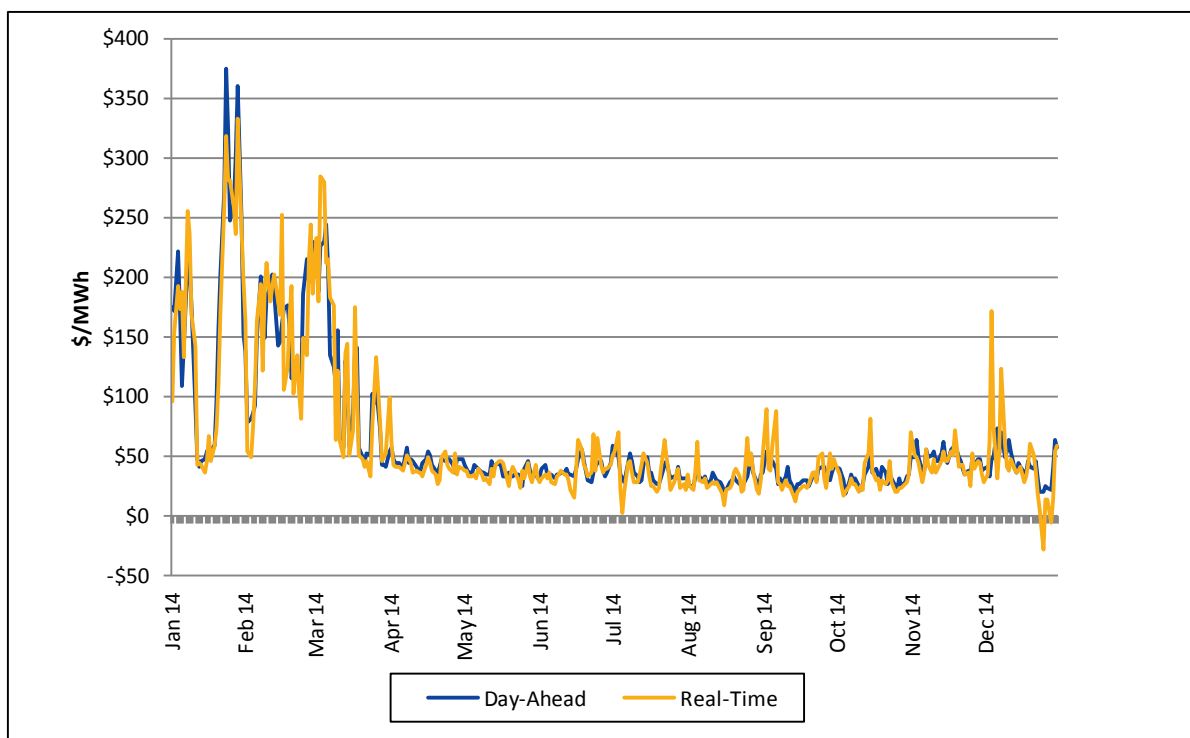


Figure 2-1: Average daily day-ahead and real-time Hub prices, 2014 (\$/MWh).

### 2.1.2 Market Structure, Competitiveness, and Mitigation

This section presents the results of the analysis of market structure (Section 3.1.7 examines conduct and performance) and presents the results of mitigation activities.

A core function of the IMM is to monitor market participant behavior and detect deviations from competitive behavior. The competitive structure of the market is determined by the number of competitors and the frequency with which suppliers are pivotal. A *pivotal* supplier has the ability to exercise market power because it is needed for meeting demand and can therefore offer energy and set prices above competitive levels, subject to offer caps and mitigation measures. Thus, market structure affects the ability of a participant to raise price above its marginal cost and sustain profits above the competitive level. The fewer competitors in the market, the easier it is for a participant to exercise market power.

Two measures of market concentration are being presented in this section. The first is a measure of market concentration focusing on the four largest competitors relative to the market as a whole. This measure is called C4 and is the percentage of the market controlled by the four largest competitors, or the simple sum of the market shares of the top-four firms. A C4 value of 100% means that the top-four firms supply all the market demand. However, this measure does not distinguish between a near-monopoly condition where one firm supplies 97% of the market with the other three supplying 1% each and a more competitive situation where each firm supplies 25% of the market.

The second measure of market concentration, the Herfindahl-Hirschman Index (HHI), provides more detail on market structures than C4.<sup>30</sup> The HHI would identify the example of a firm with

<sup>30</sup> The HHI is calculated as follows:

97% of the market share as virtually indistinguishable from a monopoly and the example of four equal market shares of 25% as more competitive. The HHI is calculated as the sum of the squared market shares of the firms in the market. The example of a firm with 97% market share would yield a value of 9,412 out of a maximum value of 10,000 for a pure monopoly. The more competitive example of four equal market shares of 25% would yield a value of 2,500. This value of 2,500 is close to the threshold used by the United States (US) Department of Justice (DOJ) to separate unconcentrated markets from concentrated markets—no such commonly used thresholds exist for C4.<sup>31</sup>

The number of hours in which a given participant's portfolio was pivotal was calculated, as measured by the Residual Supplier Index (RSI), described in Section 2.1.2.3.

The conclusions are as follows:

- The amount of generation and load held by the four largest suppliers or load-serving entities is not large enough to raise concerns about the exercise of market power at the system level.
- From the HHI analysis, the Real-Time Energy Market in New England is not concentrated at the system level.
- From the RSI analysis, the 2014 result is consistent with a structurally competitive market at the system level.

The conclusions regarding competitiveness are with respect to meeting system-wide load and operating reserve requirements. As noted above, there is little congestion that creates price separation within the ISO New England control area. If there were more frequent congestion that created price separation within the control area, structural measures of competitiveness for regions within the control area would be appropriate.

#### 2.1.2.1 Market Share Controlled by the Four Largest Competitors for the 2014 Peak Hour

In 2014, the four largest generating companies and the four largest LSEs controlled more than 40% of the supply and load in the region, with two of the largest suppliers also serving a large percentage of the load.

For the 2014 peak load hour—July 2, 2014, hour ending (HE) 3:00 p.m.—generators and imports produced 25,590 megawatts (MW) of electricity.<sup>32</sup> The four largest generation suppliers provided 40% of the total electricity produced in New England in that hour, while all

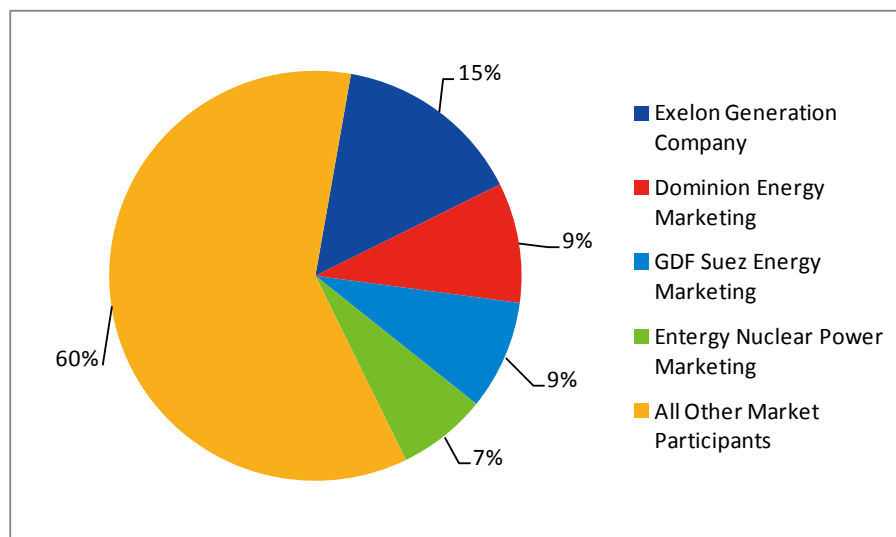
$$H = \sum_{i=1}^N s_i^2$$

where  $s_i$  is the market share of firm  $i$  in the market, and  $N$  is the number of firms. The Herfindahl Index ( $H$ ) ranges from  $1/N$  to one, where  $N$  is the number of firms in the market. Equivalently, if percentages are used as whole numbers, as in 75 instead of 0.75, the index can range up to  $100^2$ , or 10,000.

<sup>31</sup> The Department of Justice defines markets with an HHI below 1,500 points to be unconcentrated, an HHI between 1,500 and 2,500 points to be moderately concentrated, and an HHI above 2,500 points to be highly concentrated. US Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines* (Washington, DC: US Department of Justice and Federal Trade Commission, August 19, 2010), <http://www.justice.gov/atr/public/guidelines/hmg-2010.html>.

<sup>32</sup> *Hour ending* denotes the preceding hourly period. For example, 12:01 a.m. to 1:00 a.m. is hour ending 1:00 a.m. Hour ending 6:00 p.m. is the period from 5:01 p.m. to 6:00 p.m.

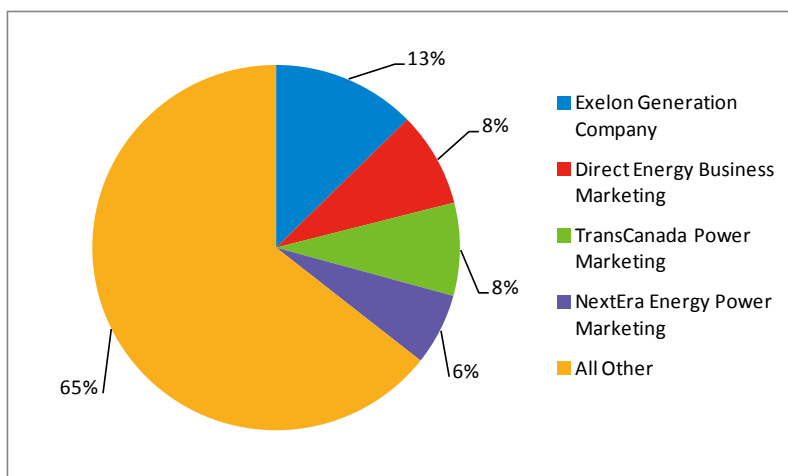
other market participants provided 60% of the electricity generated in that hour. The participant that supplied the most generation to the system during the peak hour was Exelon Generation Company, which supplied 3,812 MW (14.9%) of the total electricity generated. Dominion Energy Marketing provided 2,414 MW (9.4%); GDF Suez Energy Marketing, 2,202 MW (8.6%); and Entergy Nuclear Power Marketing provided 1,797 MW (7.0%) of total supply during the peak load hour of 2014. See Figure 2-2.



**Figure 2-2: Market share of generation by participant, peak load hour, 2014 (July 2, hour ending 3:00 p.m.).**

For the 2014 peak load hour, the total amount of electricity purchased, or *real-time load obligation* (RTLO), was 25,369 MW.<sup>33</sup> Overall, as shown in Figure 2-3, the four largest load-serving participants served 35% of the total system load for the 2014 peak load hour, while all other market participants served 65% of the total system load in that hour. Exelon had the largest real-time load obligation, serving 3,216 MW (13%) of total system peak load. Direct Energy Business Marketing served 2,124 MW of total system peak load in that hour (8%); TransCanada Power Marketing, 2,078 MW (8%); and NextEra Energy Marketing, 1,607 MW (6%).

<sup>33</sup> Losses account for the difference between the 25,590 MW of sold generation and the 25,369 MW of bought generation. This value includes exports.



**Figure 2-3: Real-time load obligation by participant, peak load hour, 2014 (July 2, hour ending 3:00 p.m.).**

Figure 2-2 and Figure 2-3 show that Exelon is in the top-four participant list for both load served and generation provided in the peak load hour of 2014. Participants with both load and generation generally have less incentive to exercise market power. Actions that would tend to raise prices for generation would come at a cost to load, and any actions that would suppress prices would come at a cost to generation. Consequently, a participant's net position and the conditions under which unilateral action might become profitable are of highest concern. The amount of generation and load held by the four largest suppliers or load-serving entities is not large enough to raise concerns about the exercise of market power.

#### 2.1.2.2 Herfindahl-Hirschman Index

Market shares of each market participant and HHIs in the Real-Time Energy Market were calculated using cleared megawatts for each real-time pricing interval. Market shares or HHIs for load zones or other subregional areas were not calculated because of the lack of transmission congestion on the system that would create separate pricing zones where lack of competition may be more of an issue.

The HHI calculation is conservative because it uses the gross generation of each participant rather than its *net generation* (i.e., a participant's generation minus its load obligation). HHIs based on estimates of market share that accounted for each participant's net generation and load position would be lower than or equal to those calculated and presented herein.

Table 2-3 summarizes the results of the HHI analysis. The median HHI calculated using the value corresponding to each day's peak hour is 638 and the median HHI calculated using the value corresponding to each day's lowest load hour is 766.<sup>34</sup> Using the DOJ's *Horizontal Merger Guidelines*, the Real-Time Energy Market in New England is not concentrated.<sup>35</sup>

<sup>34</sup> This analysis was based on lead participant by generator. Conducting the analysis by affiliate would produce a moderately different result. The IMM has estimated this difference in the range of 5% to 10%, which does not change the conclusion that the energy market is competitive.

<sup>35</sup> The Department of Justice defines markets with an HHI below 1,500 points to be unconcentrated.

**Table 2-3**  
**Median and Maximum HHI, Median Hourly Load, Number of Participants, and Share of Top Participants**  
**(by Market Share) for Each Day's Peak-Load and Lowest-Load Hours in 2014**

	Median HHI	Max HHI	Median Share of Top N Participants				Median Number of Participants	Median Load (MW)
			N = 1	N = 4	N = 8	N = 16		
<b>Peak hour</b>	638	937	13%	41%	65%	82%	123	17,277
<b>Lowest-load hour</b>	766	1,066	15%	47%	69%	85%	118	11,998

In general, the HHI is higher in low-load hours than peak hours. During low-load hours, large baseload units meet much of the demand. These baseload units are owned by a few participants, which increases the market concentration. During peak load hours, more resources owned by additional participants enter the market, lowering the market share of the participants that control the majority of baseload resources, as well as the overall market concentration. This was evident in 2014, when the top-four participants (by market share) comprised 47% of the market in the hours with the lowest load, compared with 41% for the peak hours.

#### 2.1.2.3 Residual Supply Index

The systemwide Residual Supply Index measures the percentage of real-time demand in a given hour that can be met without any capacity from the largest supplier.<sup>36</sup> The RSI also measures the number of hours in which at least one supplier is pivotal and able to exercise market power. When the RSI exceeds 100%, the system has sufficient capacity to meet demand without any capacity from the largest supplier. When the RSI is below 100%, a portion of the largest supplier's capacity is required to meet market demand, and the supplier is pivotal. As the RSI increases, the ability of market participants to set prices above competitive levels decreases. In general, the RSI is lowest during periods of high demand.

Overall, the analysis of RSI figures for 2014 suggests that the suppliers' ability to exercise market power at the system level was limited. The system-level analysis shows that pivotal suppliers existed during 37 hours in 2014, approximately 0.4% of all hours. This is a decline from 2013, when suppliers were pivotal in 123 hours. Overall, the 2014 result is consistent with a structurally competitive market. See Figure 2-4.

<sup>36</sup> For the period before the implementation of Energy Market Offer Flexibility (EMOF; also commonly known as "hourly markets"), the calculation recognizes that participants submit a single supply offer that covers the 24-hour period of the market day and that their ability to alter that offer during the course of the day is limited. As a result, the RSI calculation uses the total quantity offered from generating resources during the reoffer period.

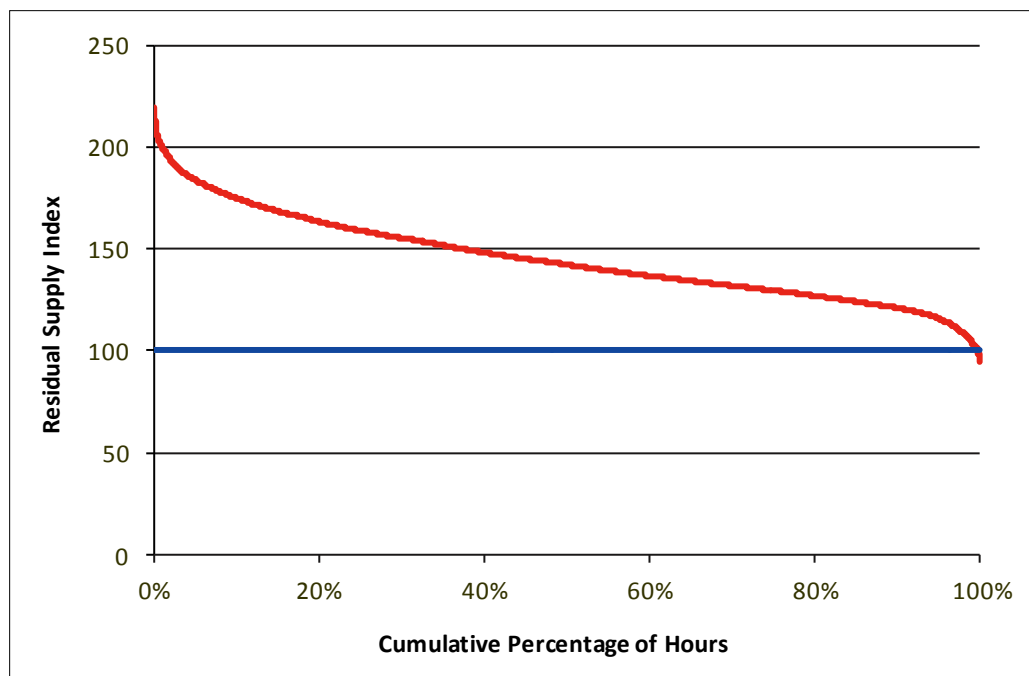


Figure 2-4: Systemwide Residual Supply Index duration curve, all hours, 2014.

#### 2.1.2.4 Mitigation

Mitigation is an automated process that prevents noncompetitive supply offers from affecting the market price. The market rules governing the mitigation process use three tests: structure, conduct, and impact. The process comprises the following:

- An evaluation of the *structure* of the competition the generator faces (e.g., the generator is part of a lead market participant's portfolio that is pivotal, systemwide, or the generator is in an import-constrained area of the system and faces less competition)
- An evaluation of the generator's *offer* (i.e., its conduct) against a reference level prepared by the IMM<sup>37</sup>
- After the evaluations, an estimation of the *impact* the generator's supply offer will have on market outcomes

The tariff requirement for determining energy market mitigation is to evaluate supply offers for all generating resources across the system that exceed the applicable reference level plus the appropriate threshold. Generator supply offers are mitigated only when they exceed the applicable reference level plus the appropriate threshold (conduct) and the supply offer raises the market price (e.g., the LMP) by a specific (impact) threshold.

Another set of mitigation rules applies to generation resources' commitment costs, and evaluates the supply offer in comparison with the resource's reference level plus an applicable threshold value. This commitment evaluation applies start-up, no-load, and energy costs at the

<sup>37</sup> A reference level generally reflects either the actual cost to the resource of generating electricity or, most frequently, in the case of hydroelectric units, the opportunity cost of producing electricity now compared with storing it and generating electricity later.

economic minimum limit (also known as a generator’s “low-load cost”). Mitigation rules that apply to generators committed for reliability have smaller thresholds because units committed for reliability often face no competition and could offer significantly above their costs.

The EMOF changes implemented in late 2014 now provide market participants with the opportunity to submit offers that vary by hour and to change offers very near real time.<sup>38</sup> These changes, which went into effect on December 3, 2014, required modifications to the mitigation rules, which included the following provisions:

- Developing hourly reference levels rather than reference levels that are fixed for an operating day
- Modifying commitment mitigation conduct tests so that they account for the low load cost over the commitment period
- Modifying the duration of mitigation such that commitment mitigation is in effect for the duration of the commitment period and energy mitigation is in effect until structural market power or market impact are no longer detected. Under the pre-EMOF rules mitigation remained in effect until at least the end of the operating day.
- Introduction of limits based on fuel prices, to the amount that start-up fees and no-load fees may be increased in real time
- Implementation of mechanisms to permit Market Participants to enter fuel price adjustments to resource reference levels to reflect hourly changes in fuel costs
- Elimination of the requirement that Market Participants with dual fuel resources submit offers based on the resource’s least cost fuel under certain conditions

Table 2-4 shows all the mitigations by occurrence for 2014. Some variation in mitigations over time is consistent with changes in system conditions.

- In January 2014, most of the mitigations were for constrained area energy, and most of the mitigations occurred on January 7, January 23, and January 28. On these days (and for the month in general), the constrained energy mitigation threshold of \$25/MWh was relatively tight in terms of the percentage of the generator offer for some units.<sup>39</sup> For example, assuming an average heat rate of 10,000 British thermal units/kilowatt-hour (Btu/kWh) and an average January 2014 gas price of almost \$24/million Btu (MMBtu), \$25/MWh represents a conduct test threshold of just over 10% of costs.
- In December 2014, the number of commitment mitigations increased due to the increased commitment flexibility under EMOF.<sup>40</sup> A greater number of commitment mitigations is expected because under EMOF the duration of mitigation is shorter. Under EMOF, a generator is subject to mitigation for the duration of the commitment only. Before EMOF was implemented, offers were subject to mitigation until at least the

<sup>38</sup> ISO New England Inc. and New England Power Pool, Docket No. ER 13-1877-000, *Energy Market Offer Flexibility Changes* (July 1, 2013) [http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/jul/er13\\_1877\\_000\\_mkt\\_offer\\_flex\\_7\\_1\\_2013.pdf](http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/jul/er13_1877_000_mkt_offer_flex_7_1_2013.pdf).

<sup>39</sup> The constrained area energy threshold is the minimum of the reference level times 1.5 and the reference level plus \$25/MWh.

<sup>40</sup> Commitment mitigation can occur when an operator takes no action to shut down a unit beyond its initial commitment, and thus remains online beyond its scheduled commitment.

end of the operating day. To put this into context, the average duration of mitigation in December 2014 was approximately two hours. In December 2013, the average duration of a mitigation event was over 23 hours.

**Table 2-4**  
**2014 Day-Ahead and Real-Time Mitigations**

Month	Commitment Mitigations	Energy Mitigations	Total
Jan	34	128	162
Feb	3	2	5
Mar	7	12	19
Apr	14	0	14
May	7	0	7
Jun	1	0	1
Jul	17	2	19
Aug	9	0	9
Sep	8	3	11
Oct	3	8	11
Nov	18	3	21
Dec <sup>41</sup>	149	4	153
<b>Total</b>	<b>270</b>	<b>162</b>	<b>432</b>

### 2.1.3 Factors that Affect Energy Prices

This section examines the relationships between real-time electric energy prices, fuel prices, and other market factors. Day-ahead market outcomes are also referenced where appropriate. Price spikes typically are explained by sudden changes in weather, fuel prices, and unplanned generator or transmission outages.

#### 2.1.3.1 Energy Prices and Real-Time Demand

The demand for electricity in New England, defined as *net energy for load* (NEL), is weather sensitive and contributes to the seasonal variation in energy prices.<sup>42</sup> As shown in Table 2-5, the NEL was highest in the third quarter of 2014, at 33,697 gigawatt-hours (GWh). The annual peak demand of 24,443 MW also occurred in the third quarter, on July 2. The weather in 2014 was milder than that in 2013. The peak load of 27,379 MW in 2013 occurred on July 19 during a five-day heat wave. The major factor behind the reduced level of demand year over year was weather related. The temperature at the time of the peak in 2014 was 88 degrees versus 95 degrees in 2013. The first quarter had the second-highest demand for electricity in 2014, at 33,528 GWh of electricity consumption, which is consistent with historical observations and is driven by the higher electrical heating demand on the system during the peak winter months. The second and fourth quarters of 2014, with more mild temperatures, had the lowest demand for electricity.

<sup>41</sup> Post-EMOF mitigations are counted in unit days.

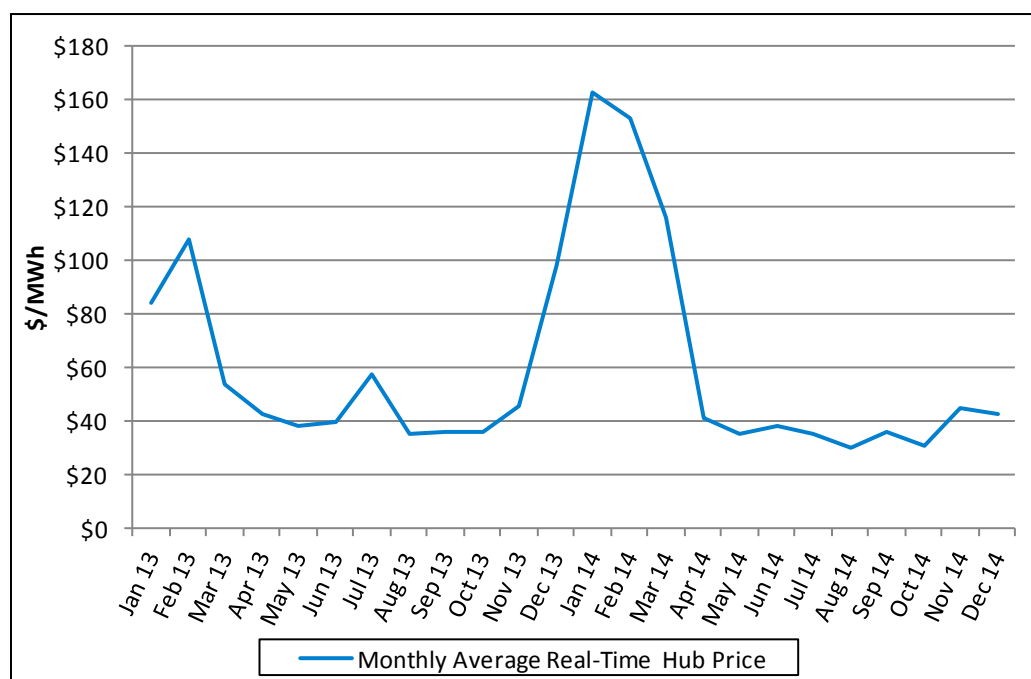
<sup>42</sup> *Net energy for load* is calculated as total generation (not including the generation used to support pumping at pumped-storage hydro generators) plus net imports.

**Table 2-5**  
**Energy Statistics, 2013 and 2014**

	2013 Annual	2014 Annual	Q1 2014	Q2 2014	Q3 2014	Q4 2014
<b>NEL (GWh)</b>	129,377	127,138	33,528	29,315	33,697	30,569
<b>Weather-normalized NEL (GWh)<sup>(a)</sup></b>	127,754	127,114	32,804	29,571	34,075	30,664
<b>Recorded peak demand (MW)</b>	27,379	24,443	21,334	21,263	24,443	19,812

(a) Weather-normalized results are those that would have been observed if the weather were the same as the long-term average.

Figure 2-5 shows real-time monthly LMPs and illustrates the effect that increased natural gas prices over the winter months in the past two years (2013/2014 and 2014/2015) had on energy prices. Of particular note is the fact that winter electricity prices, driven by high natural gas prices, exceeded electricity prices during the summer months even though the summer electrical demand exceeds the winter electrical demand (see Table 2-5). This can be seen to a large extent in January, February, and March 2014, when average prices exceeded \$100/MWh, while the average prices in July 2014, the month with the annual peak load, were slightly below \$40/MWh.



**Figure 2-5: Monthly average real-time Hub prices, 2013 to 2014 (\$/MWh).**

### 2.1.3.2 Energy Prices and Weather

This section provides an overview of how weather affected LMPs in 2014. Very cold weather throughout the first quarter (January to March) of 2014 resulted in a high demand for natural gas, which led to high natural gas prices. Natural gas was sufficiently scarce and its price was sufficiently high during this period that, at times, other fuel types were more economic. This resulted in fuel switching among resources and high LMPs. In the first quarter of 2014, the high

LMPs were the primary driver behind a higher annual average LMP for 2014 (\$63.52/MWh) compared with the annual 2013 LMP (\$56.06/MWh).

The following are highlights from the winter months in 2013/2014:

- The ISO reported that during a number of periods from December 2013 through February 2014, daily average temperatures were well below the 20-year historical average.<sup>43</sup> In March 2014, the average temperature in Boston was 6.3 degrees F (°F) below average.<sup>44</sup>
- January 2014 started with a three-day cold spell, from January 2 to January 4, with very cold temperatures (6.8°F at the peak hour).
- On Tuesday, January 7, a polar vortex that brought subzero temperatures throughout the Midwest pushed into New England, with temperatures falling into the low teens.<sup>45</sup> The peak load on January 7 was 21,334 MW. Most of the area's pipelines were operating at or near capacity, with some recording record throughputs. Much of the ISO's gas fleet was either off line due to economics or burning an alternate fuel. Temperatures began to return to normal on January 9, approaching 30°F.
- Also on January 7, a gas compressor failed on the Texas Eastern system at Delmont, PA, with a subsequent *force majeure* declaration. Gas nominations were reduced by 575,000 MMBtus, and the lateral pipeline on the Algonquin system that feeds Rhode Island and southeastern Massachusetts was physically sealed.<sup>46</sup> Six generators fueled by natural gas reported to the ISO that they could not affirm whether they would be able to procure fuel when called intraday. Many of the resources that could not provide certainty on gas procurement during this time later informed the ISO that they were available once the situation on the gas system had improved. Upon further review, these generators had gas nominations cut because of the *force majeure*, or were located on portions of the gas system where the laterals had been physically sealed.

*Comparison with 2013 Winter.* New England experienced two extreme weather events in winter 2013 (first quarter 2013). The first event, from January 21 through January 28, had been New England's coldest multiple-day stretch since 2009. The second event, occurring two weeks later in February, was a weekend blizzard that left record snowfall across the region.<sup>47</sup> The rest of the 2013 winter was relatively mild.

<sup>43</sup> The periods are December 10–17, 2013; January 1–10, 2014; January 21–30, 2014; February 6–12, 2014; February 16–19, 2014; and February 25–28, 2014. See *NEPOOL Participants Report, March 2014*, (March 7, 2014), [http://www.iso-ne.com/static-assets/documents/committees/comm\\_wkgrps/prtcpnts\\_comm/prtcpnts/mtrls/2014/mar72014/coo\\_report\\_mar\\_2014.pdf](http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2014/mar72014/coo_report_mar_2014.pdf).

<sup>44</sup> See *NEPOOL Participants Report, April 2014* (April 4, 2014), [http://www.iso-ne.com/static-assets/documents/committees/comm\\_wkgrps/prtcpnts\\_comm/prtcpnts/mtrls/2014/apr42014/coo\\_report\\_apr\\_2014.pdf](http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2014/apr42014/coo_report_apr_2014.pdf).

<sup>45</sup> See the ISO's *January 2014 FERC Data Request* (Preliminary) (January 10, 2014), [http://www.iso-ne.com/static-assets/documents/pubs/spcl\\_rpts/2014/iso\\_ne\\_response\\_ferc\\_data\\_request\\_january\\_2014.pdf](http://www.iso-ne.com/static-assets/documents/pubs/spcl_rpts/2014/iso_ne_response_ferc_data_request_january_2014.pdf).

<sup>46</sup> The Algonquin Gas Transmission is a regional interstate natural gas pipeline system that transports natural gas from pipeline interconnects in New Jersey and southeastern New England to major markets in New England.

<sup>47</sup> See *2013 Annual Markets Report* (May 6, 2014), [http://www.iso-ne.com/static-assets/documents/markets/mkt\\_anlys\\_rpts/annl\\_mkt\\_rpts/2013/2013\\_amr\\_final\\_050614.pdf](http://www.iso-ne.com/static-assets/documents/markets/mkt_anlys_rpts/annl_mkt_rpts/2013/2013_amr_final_050614.pdf).

*Market Fundamentals in the Remainder of 2014.* Temperatures during the summer and through December 2014 were milder than in 2013. Lower oil and natural gas prices, combined with the mild summer weather brought generally lower wholesale electricity prices during the rest of the year.

### 2.1.3.3 Electricity Prices and Natural Gas Prices

New England's wholesale electricity market is highly dependent on the availability of natural gas and fuel oil. A number of market forces influence the relationship between New England's natural gas and electricity markets, including the following:

- An influx of natural gas-fired generating capacity over the past 15 years<sup>48</sup>
- An aging and declining fleet of oil- and coal-fired generators, many of which were constructed during the 1960s and 1970s, and the retirement of the Vermont Yankee nuclear station. These generators would have been displaced by more efficient gas-fired generators in recent years
- Lower natural gas prices resulting from the increased production of domestic shale gas from the Marcellus Shale region of the country
- Relatively static gas pipeline capacity in New England<sup>49</sup> that has had to accommodate a 37% increase in overall natural gas consumption in New England since 1999; 95% of which was for power generation by natural gas facilities.<sup>50</sup>

The confluence of these forces has resulted in a much higher proportion of electricity being generated by gas-fired generators in New England, while pushing gas pipeline capacity to its limits during periods of peak gas demand. As a consequence, the reliability of New England's wholesale electricity grid is dependent, in part, on the owners and operators of natural gas-fired generators effectively managing natural gas deliveries during contemporaneous periods of high gas and electric power demand. Reliability is also increasingly dependent on the region's oil fleet having sufficient oil on hand to operate when the gas network is highly constrained and gas prices rise to levels that exceed the price of oil. When this occurs, oil units are dispatched more frequently.

<sup>48</sup> During the 1990s, the region's electricity was produced primarily by oil, coal, and nuclear generating plants, with very little gas-fired generation. In 1990, oil and nuclear generating plants each produced approximately 35% of the electricity consumed in New England, whereas gas-fired plants accounted for approximately 5%. Coal plants produced about 18% of New England's electricity. In contrast, by 2011, oil-fired plants produced 0.6% of electricity consumed in New England, and approximately 51% was produced by gas-fired generation. Coal production also fell by about two-thirds. ISO New England, *Addressing Gas Dependence* (July 2012), [http://www.iso-ne.com/static-assets/documents/committees/comm\\_wkgrps/strategic\\_planning\\_discussion/materials/natural\\_gas\\_white\\_paper\\_draft\\_july\\_2012.pdf](http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/natural_gas_white_paper_draft_july_2012.pdf).

<sup>49</sup> There has been no capacity change since the Maritimes and Northeast Pipeline went commercial in 1999.

<sup>50</sup> Approximately 12,000 of 14,000 MW of new capacity have come from gas-fired, combined-cycle generators. *ISO New England 2013 Regional Electricity Outlook*, p. 15 (2014), [http://www.iso-ne.com/aboutiso/fin/annl\\_reports/2000/2014\\_reo.pdf](http://www.iso-ne.com/aboutiso/fin/annl_reports/2000/2014_reo.pdf). US Energy Information Administration (EIA), "Natural Gas Consumption by End Use," webpage (data for state-level and end-user natural gas consumption, 1999–2012) (March 31, 2014), [http://www.eia.gov/dnav/ng/ng\\_cons\\_sum\\_dcu\\_SCT\\_a.htm](http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SCT_a.htm). Total consumption in New England increased by 37%; total deliveries to electric power consumers increased by 99%; and total consumption by residential, industrial, and vehicle fuels increased by 1,394%. Note that these data have not been weather normalized.

One of the most pressing challenges identified in the ISO's Strategic Planning Initiative was the region's reliance on generators fueled by natural gas. The ISO has undertaken a number of projects aimed at improving reliability through better generator performance and fuel assurance and has been, or is addressing the problem through the following initiatives:

- Increasing ten-minute non-spinning reserve to be procured in the Forward Reserve Market
- Modifying generation resource auditing requirements and procedures
- Allowing the ISO to share information concerning the scheduled output of natural gas-fired generation resources with the operating personnel of the interstate natural gas pipeline companies serving New England
- Accelerating the closing time of the day-ahead energy market
- Considering procurement of additional intra-day operating reserve capability
- Allowing intra-day reoffers
- Redesigning Forward Capacity Market performance penalties with the pay-for-performance (PFP) capacity market design and
- the Winter Reliability Programs, which will be needed until PFP become fully effective in 2018 (see Section 3.4).

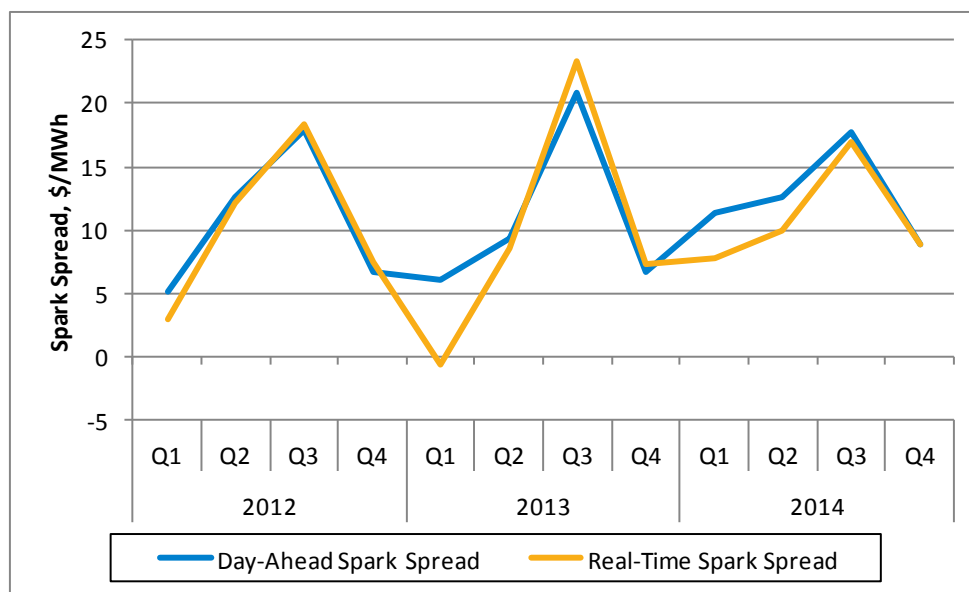
*Spark Spreads.* The *spark spread* measures the relationship between real-time electricity prices and natural gas prices. Spark spread measures the gross margin (electricity revenues minus fuel costs) from converting natural gas to electricity for a typical power plant fueled by natural gas. The data required to calculate the spark spread includes the wholesale price of electricity, the cost of natural gas (measured by a natural gas price index), and the efficiency of the generation technology in converting fuel input to electricity (i.e., the plant's *heat rate*). The spark spread for a combined-cycle gas-turbine unit (CCGT) was calculated with a heat rate of 7,800 Btu/kWh.<sup>51</sup>

Figure 2-6 presents the quarterly estimated spark spreads for natural gas based on the following:

- The simple average of the quarterly real-time Hub price for on-peak hours from January 2012 through December 2014<sup>52</sup>
- The fuel costs of a representative CCGT in New England, using the Algonquin gas price index
- A 7,800 Btu/kWh heat rate
- 100% availability

<sup>51</sup> The heat rate (Btu/kWh) for a power plant is equal to its fuel consumption divided by its generation. A unit's heat rate depends on the individual plant design, its operating conditions, and its level of electrical power output. Plants with lower heat rates are more efficient than plants with higher rates.

<sup>52</sup> For this analysis, "on peak hours" is defined as 7:00 a.m. (HE 8:00 a.m.) through 11:00 p.m. (HE 11:00 p.m.) on all nonholiday weekdays.

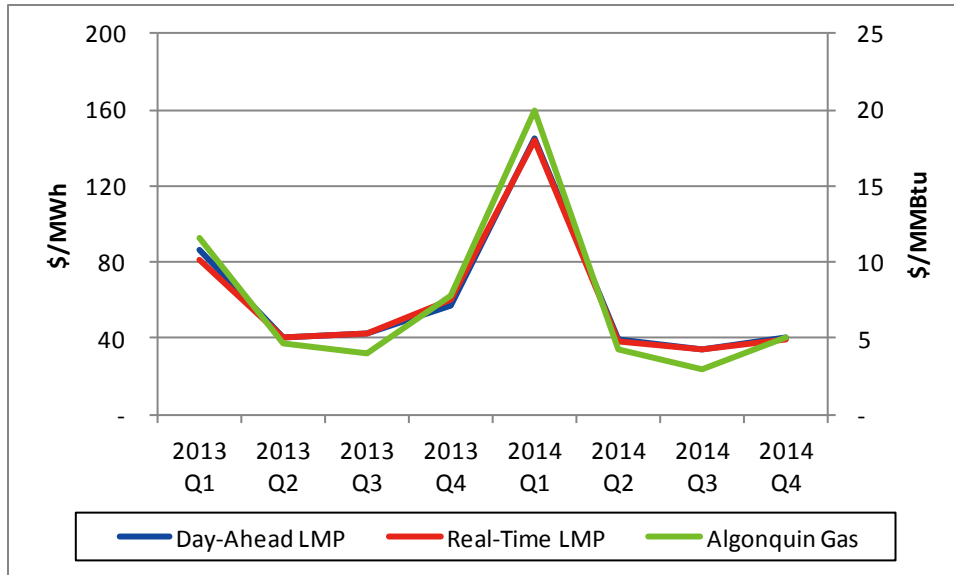


**Figure 2-6: Quarterly estimated spark spreads for on-peak hours, 2012 to 2014 (\$/MWh).**

The results show that, on average, the representative gas unit earned a positive gross margin in 2014. The annual average spark spreads were approximately \$12.90/MWh in day ahead and \$11.19/MWh in real time, an increase from 2013 day-ahead and real-time spark spreads of \$10.81/MWh and \$9.76/MWh, respectively.<sup>53</sup> Spark spreads for natural gas increased in the summer months when high loads called for less efficient gas-fired and oil-fired units to operate and set price. This increased the margin reflected in the spark spread, which is based on a more efficient resource with a 7,800 Btu/kWh heat rate. Real-time spark spreads decreased in the winter months (Q1) of 2013. This decrease in the spark spread was primarily due to high natural gas prices exceeding the price of oil for most days in January and February. In these cases, resources fueled by natural gas are displaced by oil-fired resources that set price below a level that would support a gas-fired resource, resulting in a negative calculated spark spread for the gas resources. Generally, spark spreads can be lower in the winter months because constraints on the natural gas pipelines raise the cost of natural gas, sometimes to levels that exceed the price of oil.

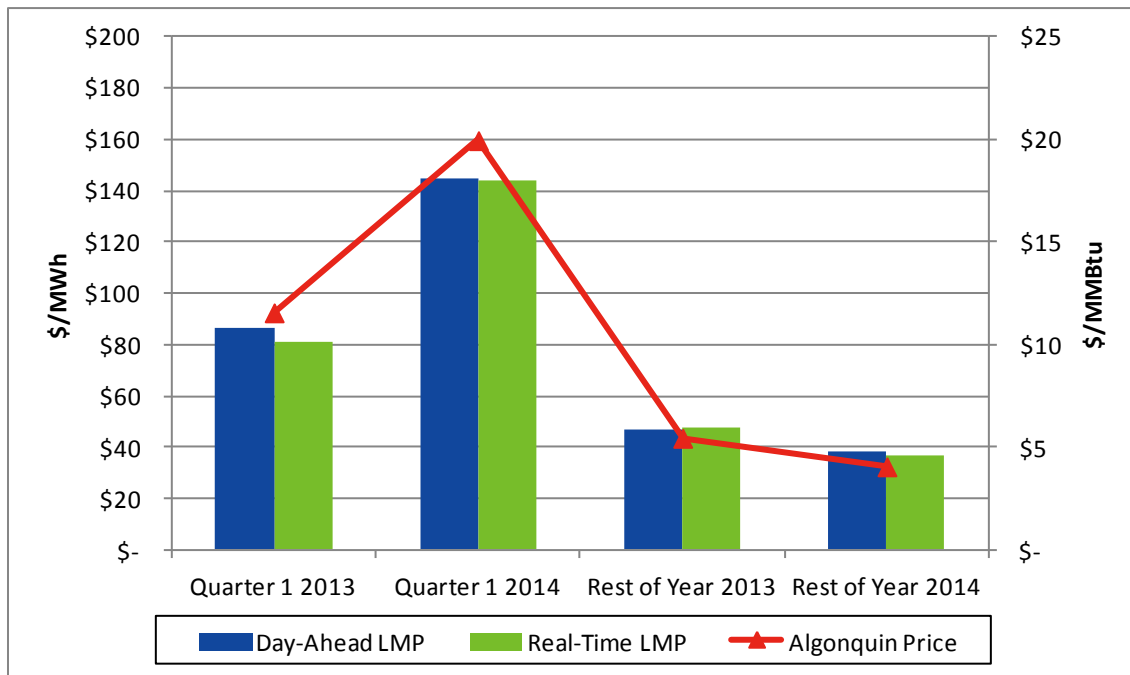
*Fuel Prices and LMPs.* Figure 2-7 shows, by quarter, average day-ahead and real-time LMPs and the Algonquin gas price for 2013 and 2014. The Algonquin gas price in quarter 1 2014 averaged \$19.96/MMBtu, 72% higher than the quarter 1 2013 price. In addition, in four days in January 2014, gas prices exceeded \$40.00/MMBtu. The figure also shows the corresponding increase in day-ahead and real-time LMPs.

<sup>53</sup> This is an idealized representation of the gross margins of a combined-cycle unit. An evaluation of revenues earned by any particular resource should take into account all unit-specific costs and operating characteristics (e.g., variable operation and maintenance costs, emission costs, minimum run time, ramp rates, economic minimum, and heat rate).



**Figure 2-7: Day-Ahead LMPs, real-time LMPs, and Algonquin average prices by quarter, 2013 to 2014.**

Figure 2-7 also shows a decrease in natural gas prices and subsequent LMPs in the second to fourth quarters in 2014 compared with the same quarters in 2013. If Quarter 1 prices are excluded, 2014 day-ahead and real-time prices fell by 18% and 23% compared with 2013 prices. See Figure 2-8.

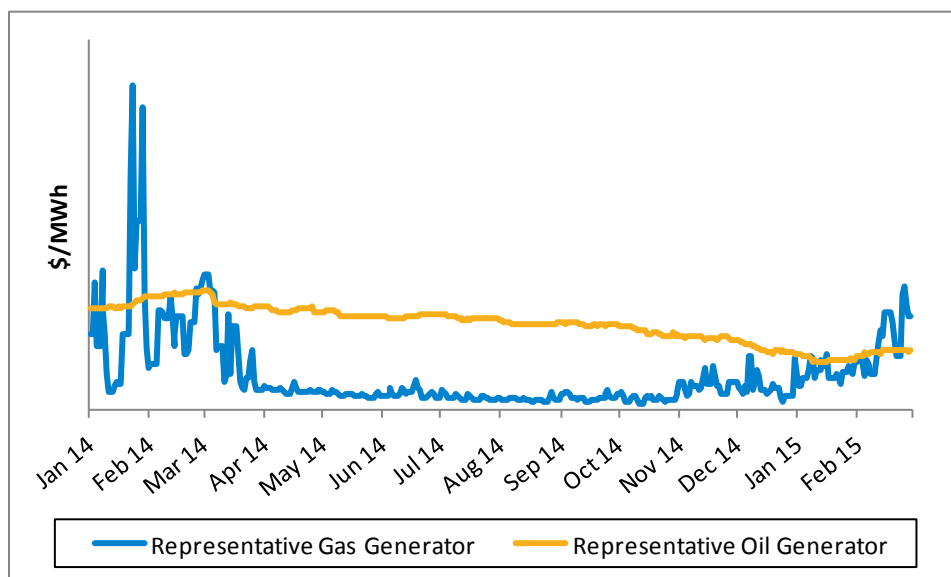


**Figure 2-8: Average LMPs (\$/MWh) and Algonquin price (\$/MMBtu), Quarter 1 and rest of year, 2013 to 2014.**

A number of factors contributed to lower LMPs from April to December 2014. As mentioned above, relatively mild weather contributed to lower loads during the summer, with a decrease in peak load of 1.8% from 2013 to 2014.

Oil prices decreased in 2014, the result of increases in US production and weaker-than-expected non-US global demand. Libyan oil production returned to the market, and the outlook for global oil demand was weak. These factors put lower price pressure on natural gas prices, given that oil is a substitute for natural gas.<sup>54</sup> On some days in late 2014, oil prices were less expensive than gas.<sup>55</sup>

Figure 2-9 presents representative generator costs for natural gas and oil units from January 1, 2014 through February 28, 2015. For 13 days in January and February 2014, generator costs for oil units were cheaper than natural gas units. It also shows that in December 2014, oil costs closed the gap with natural gas costs. For 15 days in February 2015, oil units were cheaper than natural gas units.

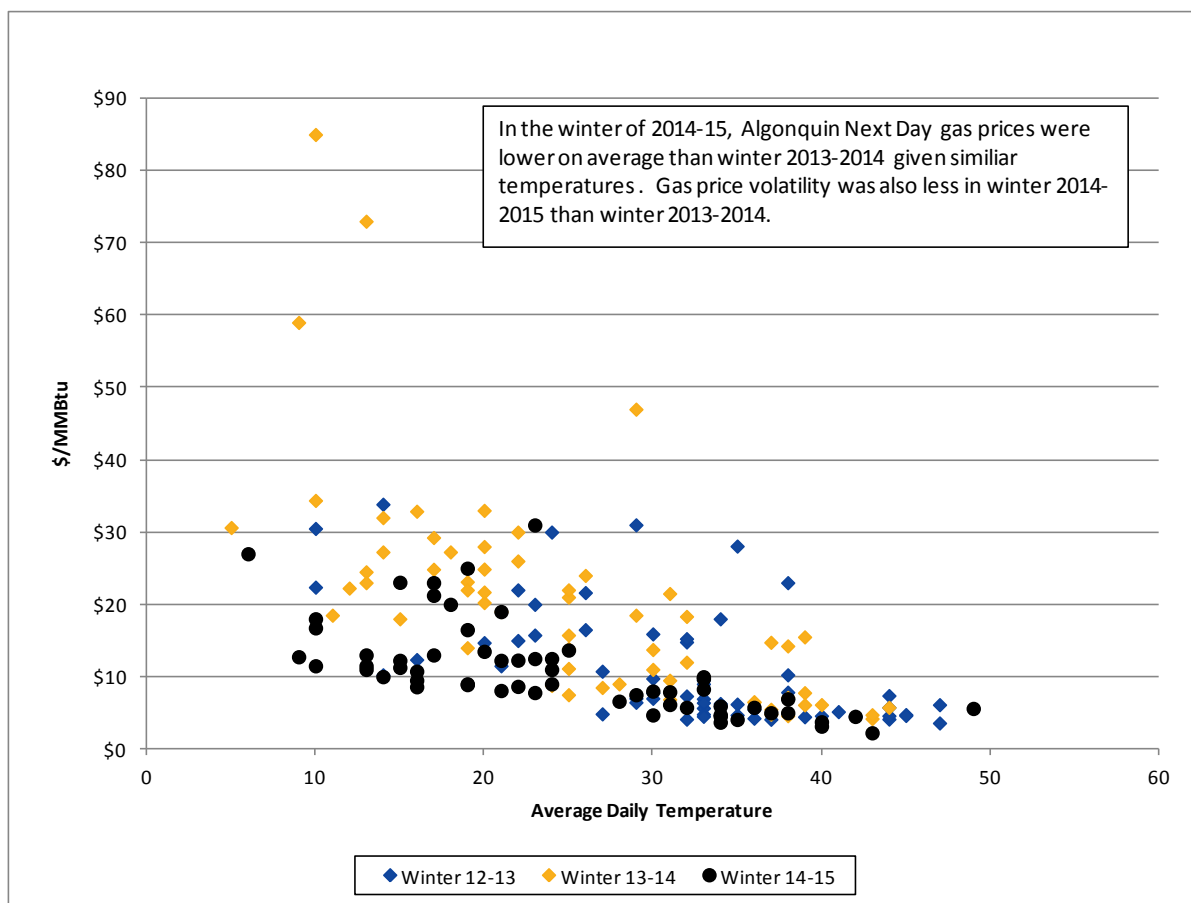


**Figure 2-9: Representative generation prices for oil and natural gas, January 2014 to February 2015 (\$/MWh).**

Gas prices have been less volatile in winter 2014/2015 compared with the past two winters. Figure 2-10 displays the median daily trade prices for Algonquin next-day trades compared with the average daily temperature for the past three winters. For example, if on a given day, there were 25 trades for the Algonquin next-day product, the price displayed for that day would be the median trade value of the 25 trades. The median daily trade prices for winter 2014/2015 (black dots), given similar temperatures, are lower than in the past two winters. Winter 2013/2014, in particular, experienced high and volatile fuel prices.

<sup>54</sup> EIA, *This Week in Petroleum* (September 24, 2014), [http://www.eia.gov/petroleum/weekly/archive/2014/140924/includes/analysis\\_print.cfm](http://www.eia.gov/petroleum/weekly/archive/2014/140924/includes/analysis_print.cfm).

<sup>55</sup> This does not necessarily mean that all the ISO's oil fleet generated on those days. Oil units generally have different price points, higher heat rates, and longer minimum run times.



**Figure 2-10: Algonquin next-day trades (median daily price), winter 2012 to 2013, winter 2013 to 2014, and winter 2014 to 2015 (December 1 through February 28).**

Finally, the natural gas supplied to New England has increased over the course of winter 2014/2015. The increased natural gas supplies come from two different sources, including LNG converted back to gas form and sent out from the importing terminal and pipeline imports from Canada:<sup>56</sup>

- In the first three weeks of January 2015, cumulative LNG sendout from the Northeast Gateway floating LNG facility and the Everett terminal, both in Massachusetts, and the Cove Point facility in Maryland totaled 10 Bcf, which is more than 3.5 times the LNG sendout during the same period in 2014, and 30% more than the LNG sendout for the entire 2013/2014 heating season (November through March).
- Cumulative imports of natural gas from Canada in the first three weeks of January 2015 totaled 28 Bcf, a 5% increase over the same period in 2014.

Also, during winter 2014/2015, natural gas from LNG facilities injected into the interstate pipeline system in New England increased more than 97%, or more than a 15.5 bcf, compared to winter 2013/2014. To put this increase in supply into context, this is enough gas to run a 500 MW CCGT with a heat rate of 8,000 Btu/kWh for approximately 162 days at full load.

<sup>56</sup> EIA, *Natural Gas Weekly Update, January 21, 2015* (January 22, 2015), [http://www.eia.gov/naturalgas/weekly/archive/2015/01\\_22/index.cfm](http://www.eia.gov/naturalgas/weekly/archive/2015/01_22/index.cfm).

The increase in LNG has come from several pipeline receipt points in New England, including Distrigas (Distrigas Receipt), Everett Interconnect, (Middlesex, MA), Excelerate Energy LP (Essex, MA), and Canaport (Maritimes/Brunswick Pipeline), with the largest increase in capacity coming from Everett Interconnect. In addition, Excelerate Energy LP supplied LNG during the winter 2014/2015, compared with winter 2013/2014 when they did not supply any LNG. See Table 2-6.

**Table 2-6**  
**LNG Scheduled Capacity Data, Dec. 1 to Feb. 28 (MMBtu)**

Receipt Points	Winter 2013/2014	Winter 2014/2015	Change
Distrigas Receipt	212,585	2,672,611	<b>2,460,026</b>
Everett Interconnect (Middlesex, MA)	2,548,528	8,119,397	<b>5,570,869</b>
Excelerate Energy LP (Essex, MA)	0	2,675,821	<b>2,675,821</b>
Maritimes/Brunswick Pipeline	13,266,225	18,129,567	<b>4,863,342</b>
<b>Total</b>	<b>16,027,338</b>	<b>31,597,396</b>	<b>15,570,058</b>

Source: Genscape

With flexible LNG supply competing against natural gas and oil as a source in the production of electricity, the price that LNG has been able to receive in the spot market has been capped at a much lower value than in 2013. This was due to the large decrease in natural gas and oil prices in winter 2014/2015 compared with winter 2013/2014 (for both heavy and light fuel oils).

*2014 Observations on Fuel Availability from the 2013 Annual Markets Report.* The *2013 Annual Markets Report* reviewed the instances when gas-fired generators were not physically available. This occurred when gas-fired generators either lacked the physical access to natural gas or failed to procure natural gas. This can increase both price and quantity risks for gas-fired generators. The report addressed the following topics:

- Gas-fired generators' use of the limited-energy generation feature
- Real-time limited-energy generation
- Generator reductions resulting from gas-availability issues

The limited-energy generator feature permitted generators to manage fuel limitations before the implementation of EMOF. The *2013 Annual Markets Report* concluded that the use of the limited-energy generation provisions in both the day-ahead and real-time markets should be restricted to instances when the availability of fuel is physically limited, and that reductions in availability for economic considerations, such as simply choosing not to purchase sufficient fuel to follow dispatch signals, is incompatible with the requirements of the tariff. With the implementation of EMOF, the use of the limited-energy generation feature has dropped significantly, and when employed, it appears to have been limited to managing actual limitations on availability.

A decrease in generation reductions resulting from gas availability issues has also been observed. This decrease is coincident with the FERC orders clarifying the obligations of resources to procure fuel, the increase in gas supply, the change in the day-ahead market timeline, and the implementation of EMOF.

#### 2.1.3.4 System Events and Energy Prices

System events affected prices on two days in 2014. This section provides an overview of these events.

*Operating Procedure No. 4 (OP 4) on September 28, 2014.*<sup>57</sup> The following is a summary of the main system and market observations from the event:

- Loads running over forecast in the late afternoon and evening, along with limited generation, resulted in a brief capacity and operating reserve shortage.
- The ISO implemented Action 1 of OP 4 to inform resources that a capacity shortage existed and to begin to allow the depletion of 30-minute operating reserves.
- Demand response was not dispatched during the OP 4 event.
- Operating reserve levels recovered to sufficient levels after the evening peak occurred, which allowed for the cancellation of OP 4 at 8:30 p.m.

Price analysis. On September 28, 2014, real-time hub LMPs rose in HE 7:00 p.m. to 9:00 p.m. due to an operating reserve deficiency. The deficiency resulted in positive operating reserve pricing in HE 7:00 p.m. through HE 11:00 p.m. The hourly 10-minute spinning reserve (TMSR) price (see Section 2.2.1) peaked at \$426.27/MWh in HE 8:00 p.m. The positive operating reserve pricing resulted in a peak real-time hub LMP for the day of \$507.17/MWh in HE 8:00 p.m. See Figure 2-11.

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<sup>57</sup> ISO New England Operating Procedure No. 4, *Action during a Capacity Deficiency* (August 12, 2014), [http://www.iso-ne.com/rules\\_proceeds/operating/isone/op4/op4\\_rto\\_final.pdf](http://www.iso-ne.com/rules_proceeds/operating/isone/op4/op4_rto_final.pdf).

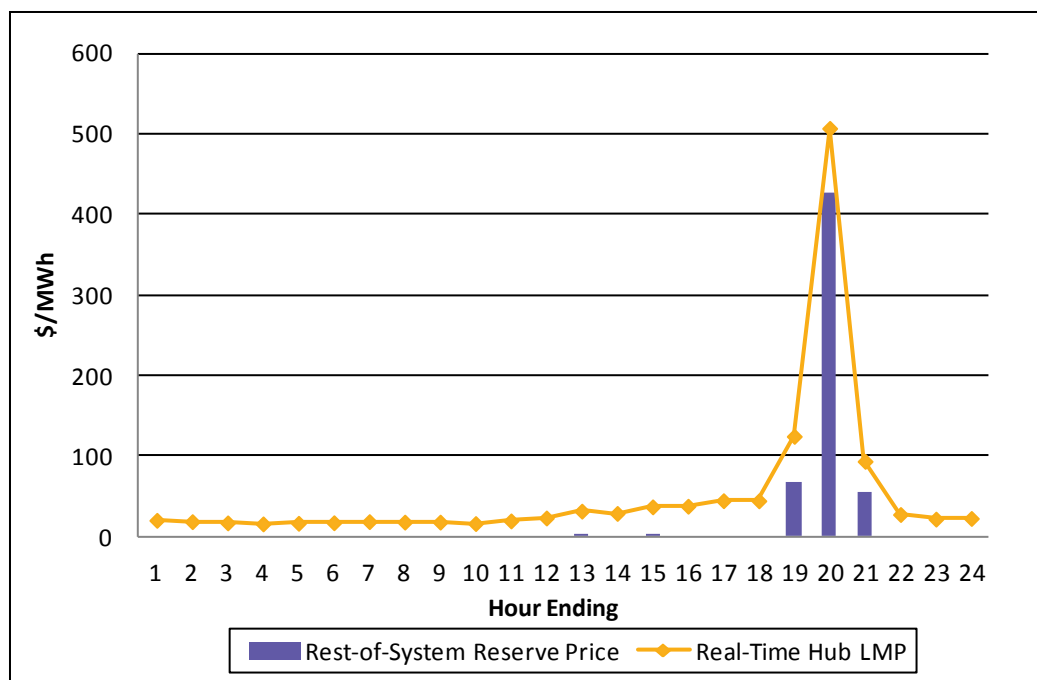


Figure 2-11: Real-time Hub LMP and 10-minute spinning reserve price, September 28, 2014.

Operational analysis. On the evening of Sunday, September 28, 2014, the New England region experienced tight capacity conditions due to loads that were slightly over the forecast and generating unit reductions.<sup>58</sup> At approximately 6:10 p.m., a large generating unit rated at approximately 600 MW was forced off line due to a mechanical problem. These two contributing factors resulted in the ISO declaring Master/Local Control Center 2 (M/LCC2) (Abnormal Conditions Alert) for all New England at 6:50 p.m. At 7:00 p.m., the ISO declared OP4 Action 1 due to a deficiency in 30-minute operating reserves (see Section 2.2.1). After the evening peak, the decrease in the New England load allowed for the cancellation of OP 4 Action 1 at 8:30 p.m. and the cancellation of M/LCC2 at 10:00 p.m. Figure 2-12 illustrates the time at which OP 4 Action 1 was declared and cancelled, alongside the actual and required operating reserves throughout the OP 4 event and evening hours.

<sup>58</sup> Loads were approximately 290 MW over the forecasted load in the peak hour, HE 8:00 p.m.

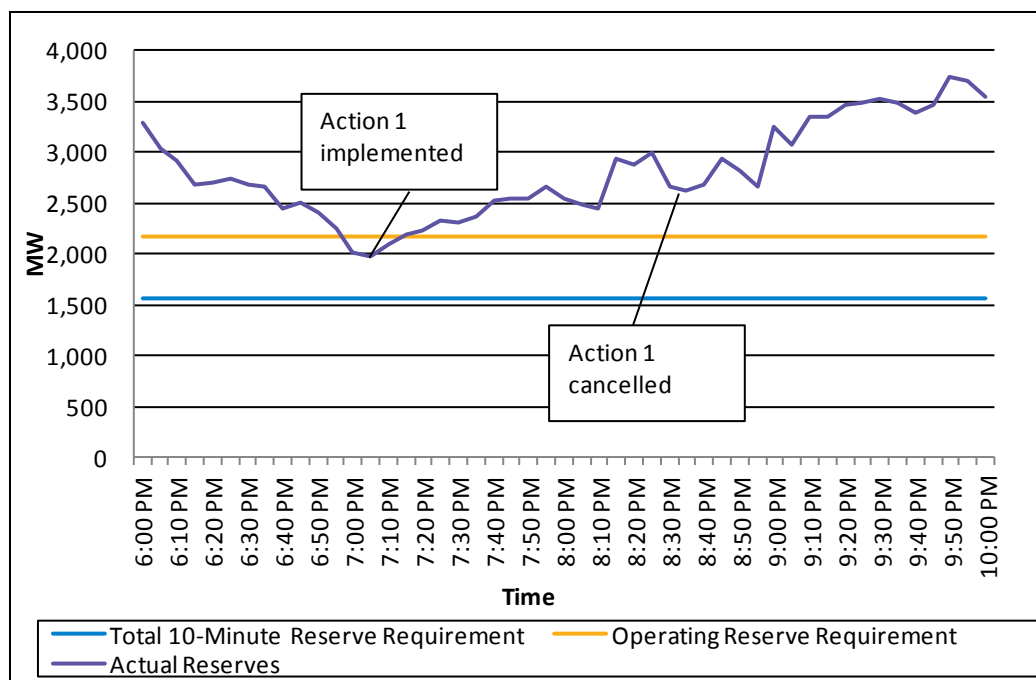
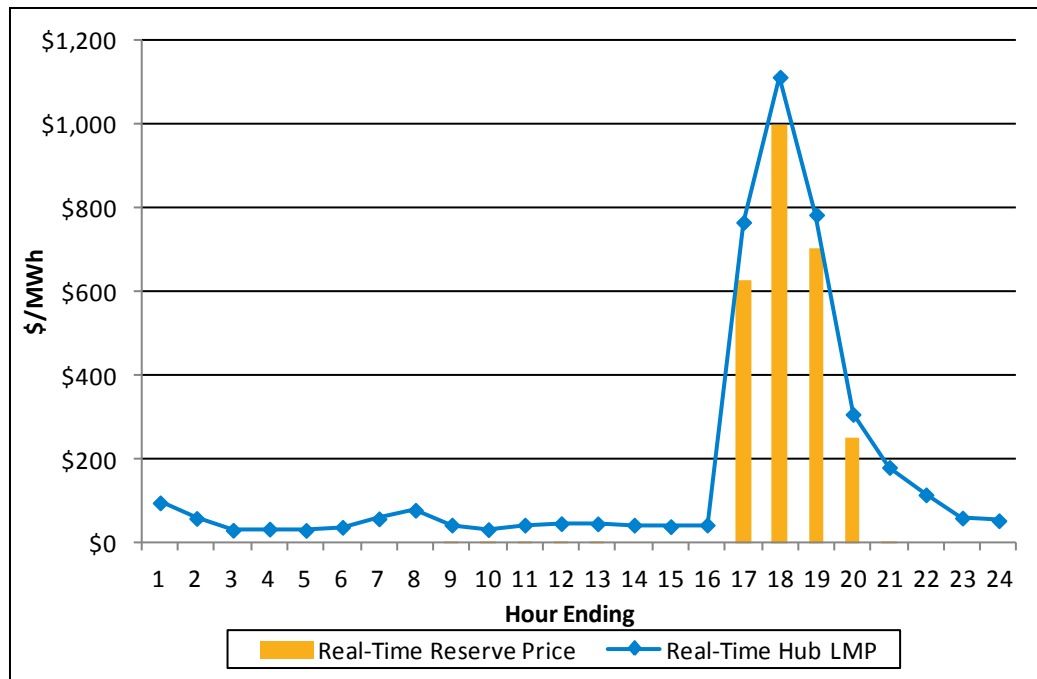


Figure 2-12: Operating reserves and requirements during OP 4 event, September 28, 2014.

OP 4 on December 4, 2014. The following is a summary of the main system and market observations:

- The curtailment of nearly 2,000 MW from Hydro-Québec TransÉnergie (HQ) into New England resulted in a brief capacity and operating reserve shortage.
- The ISO implemented Action 1 of OP 4 to inform resources that a capacity shortage existed and to begin to allow the depletion of 30-minute operating reserves.
- Demand response was not dispatched during the OP 4 event.
- Sufficient operating reserves were available after the evening peak occurred, which allowed for the cancellation of OP 4 at 8:45 p.m.

Price analysis. On December 4, 2014, real-time hub LMPs rose in HE 5:00 p.m. to 8:00 p.m. due to an operating reserve deficiency. The deficiency resulted in positive operating reserve pricing from HE 5:00 p.m. through HE 8:00 p.m. The hourly TMSR price peaked at \$1,000/MWh in HE 8:00 p.m. The positive operating reserve pricing resulted in a peak real-time hub LMP for the day of \$1,113.42/MWh in HE 6:00 p.m. See Figure 2-13.



**Figure 2-13: Real-time Hub LMP and 10-minute spinning reserve price, December 4, 2014.**

Operational analysis. On the afternoon of Thursday, December 4, 2014, the New England region experienced tight capacity conditions due to the curtailment of approximately 2,005 MW from Hydro-Québec TransÉnergie into New England due to the loss of two major 735 kV transmission lines in Québec. At 4:00 p.m., M/LCC 2 was declared for all New England. At 4:15 p.m., OP 4 Action 1 was implemented to manage the deficiency in 30-minute operating reserve. Figure 2-14 illustrates the time at which OP 4 Action 1 was declared, alongside the actual and required operating reserves throughout the OP 4 event and evening hours.

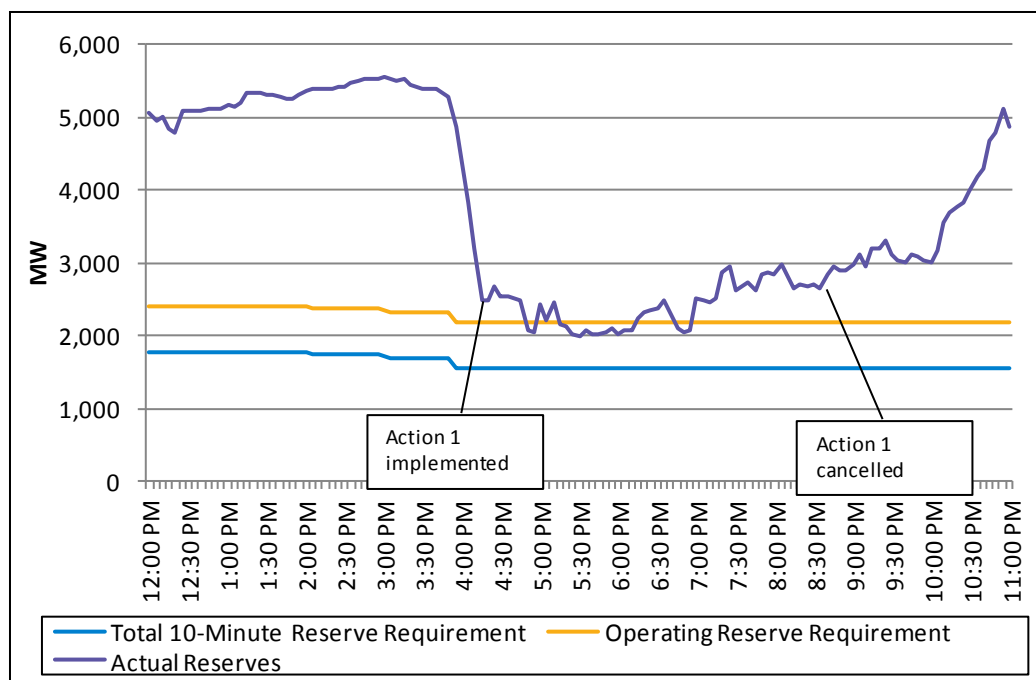
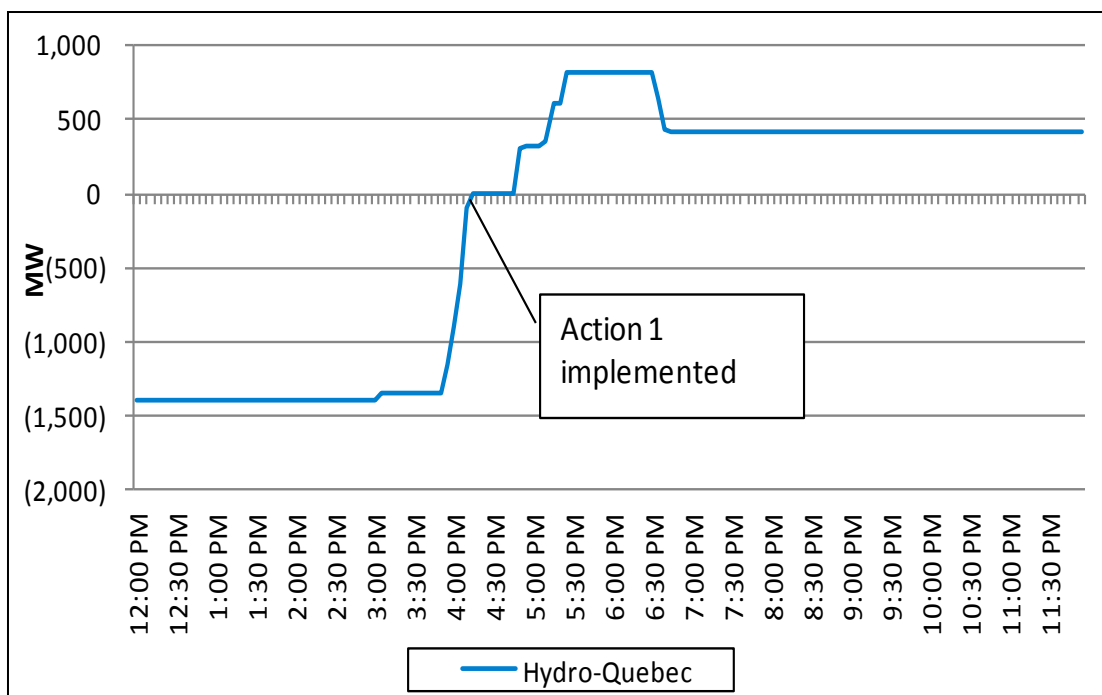


Figure 2-14: Operating reserves and requirements during OP 4 event, December 4, 2014.

In addition to the emergency energy provided to HQ from New England, HQ provided up to 500 MW of capacity-backed emergency energy to New Brunswick, which was “wheeled through” New England and returned to HQ through Phase II.<sup>59</sup> Figure 2-15 illustrates the flow of energy between New England and Hydro-Québec before the trip of the lines in Québec and during the OP 4 event. Negative values in the figure indicate that the New England region was importing energy, and positive values indicate that New England was exporting energy.

<sup>59</sup> *Wheel through* refers to the transmission of electric power from one system to another over a third party’s transmission lines. *Phase II* refers to the DC interconnection ISO New England has with Hydro-Québec.



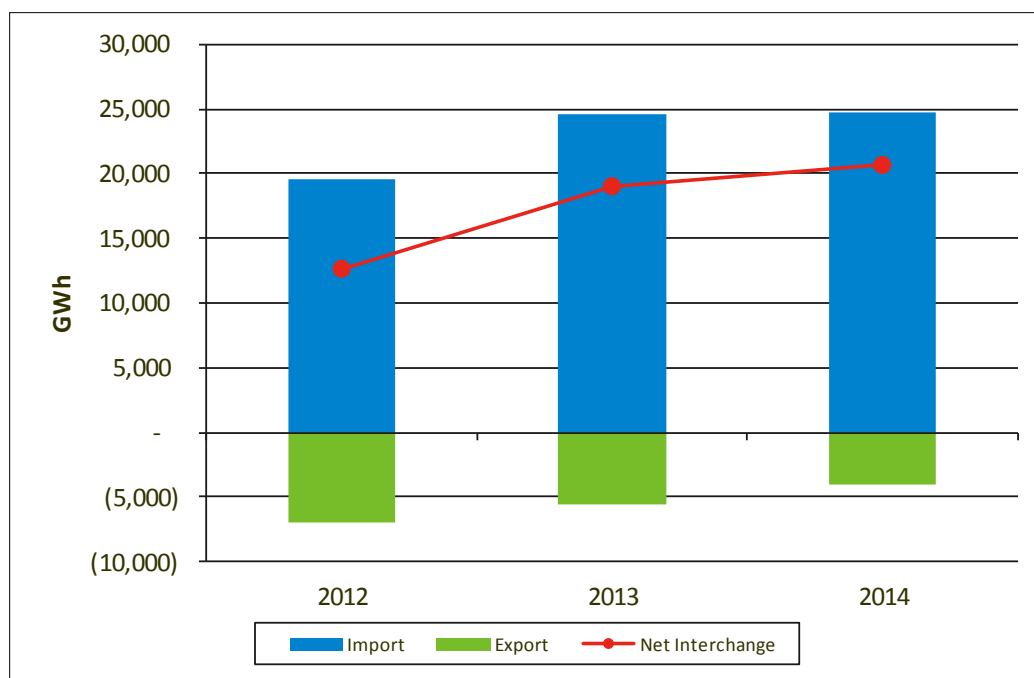
**Figure 2-15: External flow between Hydro-Québec and New England during OP 4 event, December 4, 2014.**

**Note:** Negative values in the figure indicate that the New England region was importing energy, and positive values indicate that New England was exporting energy.

After the evening peak, at 8:45 p.m., the ISO cancelled OP 4 Action 1. The M/LCC2 was cancelled on the following day, Friday, December 5, at 6:00 p.m.

#### 2.1.3.5 Energy Prices and External Transactions

In 2014, New England was a net importer of power. Net imports from Canada exceeded net exports to New York (NY). The net interchange with neighboring balancing authority areas totaled 20,677 GWh for 2014, a 9% increase compared with the previous year. The increase in the net interchange is the result of both fewer exports and slightly greater imports in 2014 compared with 2013. The reduction in exports was partially due to the loss of a transmission facility between New England and New York that is predominantly a net exporter of power to New York. See Figure 2-16.



**Figure 2-16: Scheduled imports and exports and net external energy flow, 2012 to 2014 (GWh).**

The lower levels of New England exports are not directly attributable to a price differential between New England and New York. The current rules and systems that govern the interchange between New York and New England do not allow all possible gains to be realized from trade between the regions. Ideally, power should flow from the region with lower costs to the region with higher costs. However, the current scheduling system does not allow market participants to modify their bids and offers during the day, nor does it allow the ISO to optimize tie flows with sufficient frequency to ensure the efficient scheduling of the ties under all conditions. As a result, on the northern alternating-current (AC) ties between the New York Independent System Operator (NYISO) and ISO New England, power only flows in the apparent “right” direction about half the time, that is, in the direction expected based on observable price differences between the Roseton and the Sandy Pond pricing locations.<sup>60</sup> See Table 2-7.

**Table 2-7  
Percentage of Time Transactions Are Scheduled in the Direction of the Higher Price  
on the Roseton Interface, 2012 to 2014**

Year	Real-Time (%)	Day-Ahead (%)
2012	52	57
2013	52	55
2014	56	49

In addition, production costs would be lower if the existing transmission interconnections were scheduled more efficiently, that is, scheduled in the prevailing direction of price up to the available total transfer capability (TTC). The data indicate that during many hours of the year,

<sup>60</sup> *Roseton* and *Sandy Pond* are the “border,” or proxy bus, pricing nodes for real-time, hourly integrated LMPs for NYISO and ISO New England.

ample transmission capacity is available to move additional power from the lower-cost region to the higher-cost region.

On January 20, 2012, stakeholders agreed to investigate coordinated transaction scheduling (CTS), which employs higher-frequency scheduling and eliminates charges and credits on external transactions that deter trade. FERC accepted CTS on April 19, 2012.<sup>61</sup> The ISO anticipates that CTS will be implemented at certain locations between New England and New York in 2015. The IMM supports the ongoing efforts to implement CTS.

#### *2.1.3.6 Energy Prices and Marginal Units*

The LMP is set by the cost of the next megawatt that would have to be dispatched to meet an incremental change in load at the pricing location. The resource that sets price is called the marginal unit. Because the price of electricity changes as the price of the marginal unit changes, and the price of the marginal unit is largely determined by its fuel type, examining marginal units by fuel type helps understand changes in electricity prices. The system has at least one marginal unit associated with meeting the energy requirements on the system during each pricing interval. If transmission is not constrained, the marginal unit is classified as the *unconstrained* marginal unit. In intervals with binding transmission constraints, an additional marginal unit exists for each binding constraint.

In 2014, unconstrained pricing intervals accounted for approximately 88% of all pricing intervals. When considering both unconstrained and constrained intervals, natural gas was the marginal fuel during 70% of all pricing intervals, followed by coal and pumped-storage generation, which were marginal in 8% and 7% of all pricing intervals, respectively. These percentages are comparable with data from the past few years, with the exception of 2012, when coal prices (and associated transportation costs) converged with the natural gas prices. The percentage of time natural gas set the price has been high, compared with other fuel types, and further illustrates New England's reliance on natural gas. See Figure 2-17.

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<sup>61</sup> FERC, *Order Accepting Tariff Revisions, Subject to a Compliance Filing*, Docket No. ER12-1155-000 (April 19, 2012), [http://www.iso-ne.com/regulatory/ferc/orders/2012/apr/er12-1155-000\\_4-19-12\\_order\\_accept\\_cts.pdf](http://www.iso-ne.com/regulatory/ferc/orders/2012/apr/er12-1155-000_4-19-12_order_accept_cts.pdf).

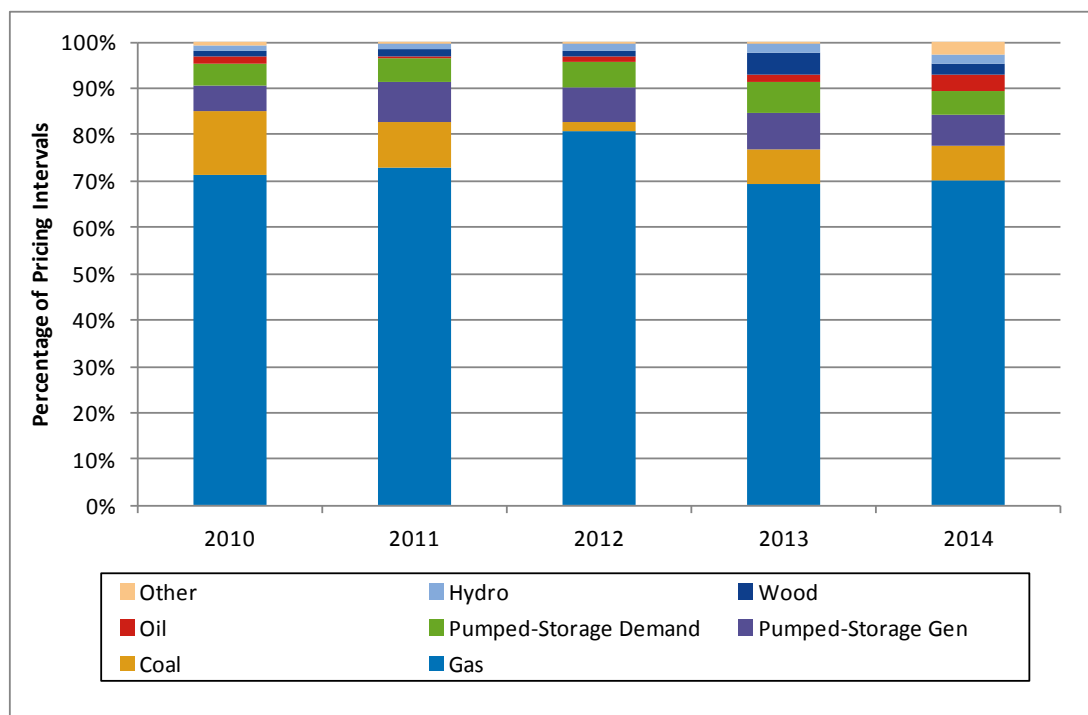


Figure 2-17: Marginal fuel-mix percentages of all pricing intervals, 2014.

#### 2.1.4 Reliability and Operations Assessment

This section discusses ISO actions to ensure real-time reliability and an assessment of ISO operations. It includes a review of Net Commitment-Period Compensation (NCPC) payments to suppliers.

Total NCPC payments in 2014 totaled \$174.1 million. This total includes both daily-reliability NCPC payments and generator performance audit (GPA) NCPC payments. Details of the payments made in 2014 are described below.

##### 2.1.4.1 Daily Reliability NCPC Payments

The ISO is required to operate New England's wholesale power system to the reliability standards developed by North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the ISO through open stakeholder processes.<sup>62</sup> To meet these requirements and maintain daily system reliability, the ISO may commit resources, in addition to those cleared in the Day-Ahead Energy Market, to ensure capacity adequacy in real-time. Resources that operate at the ISO's instruction but do not recover their as-bid costs through energy market revenues are paid one of the following types of compensation, depending on the reason for the commitment:<sup>63</sup>

<sup>62</sup> These requirements are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures. For more information on NERC standards, see <http://www.nerc.com/pa/stand/Pages/default.aspx>. For more information on NPCC standards, see <https://www.npcc.org/Standards/default.aspx>. The ISO's system operating procedures are available at [http://www.iso-ne.com/rules\\_proceeds/operating/isone/index.html](http://www.iso-ne.com/rules_proceeds/operating/isone/index.html).

<sup>63</sup> A system's *first contingency* (N-1) is when the power element (facility) with the largest impact on system reliability is lost. A *second contingency* (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that at that time has the largest impact on the system.

- Economic/first-contingency NCPC
  - Reliability costs paid for generation committed and dispatched to provide energy on short notice and create operating reserves that allow the system to recover from the loss of the first contingency within the specified period
  - Reliability costs paid for the commitment and dispatch of generation to provide systemwide stability or thermal support or to meet systemwide electric energy needs during the daily peak hours
  - Reliability costs incurred for generation committed for peak hours but are still on line after the peak hours to satisfy minimum run-time requirements
- Local second-contingency NCPC
  - Reliability costs paid to generating units providing capacity in constrained areas
- Voltage reliability NCPC
  - Reliability costs paid to generating units dispatched by the ISO to provide reactive power for voltage control or support
- Distribution reliability NCPC
  - Reliability costs paid to generating units that are operating to support local distribution networks

*Daily Reliability Payments for 2014.* As shown in Table 2-8, daily reliability payments totaled \$173.7 million in 2014, or about 2.1% of the total wholesale cost of electricity.

**Table 2-8**  
**Total Daily Reliability Payments by Quarter, 2014 (\$ Millions)**

	2014	Q1	Q2	Q3	Q4
<b>Total Daily Reliability Payments</b>	173.7	107.7	16.8	21.5	27.8

As shown in Table 2-9, daily reliability payments in 2014 increased by \$15.7 million (10%) from 2013, and first-contingency NCPC payments increased by \$36.2 million (37%) from 2013. Generators fueled by natural gas were committed in late January 2014 to supply energy during extremely cold weather days when gas prices were very high. These resources were economically displaced by less expensive oil-fired resources that set the market price. The market price was insufficient to cover the cost of the higher-cost of generators fueled by natural gas because the price was set by the lower-cost oil-fired resources. The resulting revenue deficiency was paid through NCPC. Overall, 62% of all NCPC payments were paid in the first quarter of 2014, which was a period of cold weather that resulted in high natural gas prices, fuel switching, and high LMPs (see Section 2.1.3.2). Second-contingency payments decreased by \$5.6 million (15%) compared with 2013, and local distribution payments decreased by 83%. Additional local capacity was committed in January and February 2013 during a cold snap and a blizzard. Voltage payments decreased by 63%, the result of variations in loads, generation, and transmission mix.

**Table 2-9**  
**Total Daily Reliability Payments, 2013 and 2014 (\$ Millions)**

Payment Type	2013	2014	Difference	% Change
Economic and first-contingency payments	98.2	134.3	36.2	37%
Second-contingency reliability payments	38.0	32.4	(5.7)	-15%
Distribution	5.2	0.9	(4.4)	-83%
Voltage	16.6	6.2	(10.4)	-63%
<b>Total</b>	<b>158.0</b>	<b>173.7</b>	<b>15.8</b>	<b>10%</b>

Table 2-10 shows that approximately 42% of all reliability payments in 2014 were made in January. Additional results are as follows:

- In January, February, and March 2014, New England experienced extended periods of very cold weather.
- In December 2014, NCPC was paid to a number of generators in real time as a result of hours with low or negative LMPs.

**Table 2-10**  
**Daily Reliability Payments by Month, 2014 (\$ Millions)**

Month	Total Reliability Payment
Jan	73.3
Feb	16.3
Mar	18.1
Apr	7.0
May	3.9
Jun	5.9
Jul	9.7
Aug	5.5
Sep	6.3
Oct	7.8
Nov	6.4
Dec	13.5

#### 2.1.4.2 Generator Performance Audit NCPC Payments

NCPC payments for generator performance audits became effective on June 1, 2013.<sup>64</sup> NCPC payments to participants for this category are incurred for the following:

- Performance audits of on-line and off-line operating reserves and for seasonal claimed capability audits initiated by the ISO rather than the participant
- Dual-fuel testing services as part of the 2014/2015 Winter Reliability Program.<sup>65</sup>

Table 2-11 shows the total GPA NCPC payments made to generators during the reporting period by month.

**Table 2-11**  
**GPA Payments, 2014 (\$ Thousands)**

Month	Real-Time Generator Performance Audit Payment
Jan	0
Feb	0
Mar	0
Apr	0
May	0
Jun	0
Jul	0
Aug	0
Sep	0
Oct	0
Nov	380.3
Dec	25.0
<b>Total</b>	<b>405.2</b>

#### 2.1.4.3 Winter Reliability Program

The winter reliability programs for 2013/2014 and 2014/2015 constitute the ISO's most direct actions to address fuel assurance, recognizing that winter solutions are a short-term measure and do not drive long-term investment.

The central component of the winter reliability programs has been the provision of direct financial incentives to generators to maintain on-site oil inventories. By ensuring that oil- and dual-fuel-fired generators do not run out of oil, the winter programs have directly addressed concerns about generator reliance on pipeline deliveries of fuel during periods of high natural

<sup>64</sup> ISO New England and NEPOOL, *Market Rule 1 Revisions Relating to Auditing of Generation Resources*, Docket No. ER13-1323-000 (November 6, 2012), [http://www.iso-ne.com/regulatory/ferc/filings/2012/nov/er13-323-000\\_11-6-2012\\_audit\\_claim.pdf](http://www.iso-ne.com/regulatory/ferc/filings/2012/nov/er13-323-000_11-6-2012_audit_claim.pdf).

<sup>65</sup> *Market Rule 1*, Appendix K, *Winter Reliability Solutions*, [http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect\\_3/mr1\\_append\\_k.pdf](http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_k.pdf).

gas demand and stress on the pipeline system. The ISO concluded that the resources and inventory procured through the 2013/2014 Winter Reliability Program were vital to grid operation during stretches of extremely cold weather.

The 2014/2015 Winter Reliability Program built off the prior winter program, providing incentives for resources to enter into contracts for liquefied natural gas and including additional market monitoring changes designed to provide dual-fuel resources greater flexibility. In an order issued in January 2015, FERC clarified that any interim winter program, if deemed necessary, must be “an appropriate market-based solution.”<sup>66</sup> On February 19, 2015, the ISO filed for rehearing of this order, urging the commission to permit an expansion of the existing winter program; alternatively, the ISO proposed additional increases to the Reserve Constraint Penalty Factors (see Section 2.2) to provide incentives to generators to be available in the real-time market during shortage conditions. On April 17, 2015, the Commission granted the ISO’s rehearing request, finding that an expanded version of the winter program might better produce the desired reliability results than the introduction of a market-based solution. The Commission also noted its expectation that the ISO abide by its commitment to work with stakeholders to expand any future out-of-market winter reliability program so that it is fuel neutral, or explain why a fuel neutral program is not feasible.<sup>67</sup>

The results of the 2014/2015 Winter Reliability Program have been positive. The program has drawn robust participation from oil-, gas-fired, and dual-fuel generators that stocked oil and contracted for liquefied natural gas. The program also attracted new demand-response resources. During February 2015’s extremely cold weather, oil resources had sufficient fuel to maintain reliability. Finally, six units representing over 1,700 MW took advantage of new incentives for generators to add dual-fuel capability, which is significant for long-term fuel security. The pay-for-performance market construct will be fully implemented beginning June 1, 2018. This construct will provide strong incentives for resources to be available and perform well during shortage conditions and should eliminate the need for a winter reliability program.

#### *2.1.4.4 Exemption for dual-fuel generators from the requirement to provide documentation when natural gas and oil prices converge*

In July 2014, the ISO proposed a package of market rule changes to implement the Winter Reliability Program 2014/ 2015.<sup>68</sup> As part of this package, changes were proposed to the requirements for dual-fuel generators to justify and demonstrate the use of the higher-priced fuel during periods of heightened gas price and volume uncertainty. Previously, a market participant with a dual-fuel generator was required to notify the IMM of its intention to burn the higher-priced fuel, explain why the lower-priced fuel was unavailable, and, afterwards, provide documentation to prove that it actually burned the higher-priced fuel. If the market participant failed to do this, the IMM would mitigate the dual-fuel generator’s supply offer (calculated using the higher-priced fuel) by replacing it with the dual-fuel generator’s reference level calculated based on the lower-cost fuel. This could have the effect of reducing the dual-fuel generator’s NCPC payments.

<sup>66</sup> See *Order on Clarification*, 150 FERC ¶ 61,029 at P 10 (January 20, 2015).

<sup>67</sup> See *Order Granting Rehearing*, 151 FERC ¶ 61,052 at P 17 (April 17, 2015).

<sup>68</sup> ISO New England Inc. and New England Power Pool, Docket No. ER 14-2047-001, *Winter 2014-15 Reliability Program* (July 11, 2014), [http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14\\_2407\\_000\\_win\\_rel\\_pro\\_7\\_11\\_2014.pdf](http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14_2407_000_win_rel_pro_7_11_2014.pdf)

The proposed change addressed concerns that the prevailing rules diminished the economic benefits of investing in dual-fuel capability by restricting a market participant's ability and operational flexibility to manage its fuel supply during times of uncertainty and price volatility in the natural gas market. During such times, market participants often have difficulty determining in advance of submitting a supply offer which fuel—oil or natural gas—would cost the least.

The IMM proposed that a dual-fuel generator be exempt from the requirement to justify and verify the use of the higher-priced fuel when oil and natural gas index prices converge. Specifically, this convergence would be when the ratio of the generator's higher-priced fuel index price to its lower-priced fuel index price is less than or equal to 1.75.<sup>69</sup> The ratio is based on a historical analysis of requests from generators to be evaluated on their higher-priced fuel, known as a dual-fuel override (DFO) request, or to be evaluated on a different price than the default index price, known as a fuel-price adjustment (FPA) request. Market participants submit DFO and FPA requests when they are faced with uncertainty of being able to procure the lower-priced fuel quantity needed to satisfy their supply-offer obligations or are exposed to natural gas price risk.

*Basis for the 1.75 Ratio Exemption Rule.* Based on analysis as described in the ISO's July 11, 2014, filing, the natural gas index price is likely to be representative of the generators' fuel price for a given pipeline when the ratio of the higher-priced fuel (typically oil) to the lower-priced fuel (natural gas) is fairly large. Conversely, the natural gas index price for any given pipeline is less likely to be representative of the price faced by any particular generator on a pipeline when the ratio of the higher-priced index to the lower-priced index is relatively low.

When the ratio is low (when gas and oil prices converge), dual-fuel generators are also more likely to offer on the basis of oil, given both the volume and price uncertainty associated with the procurement of natural gas in the spot market. The ratio of 1.75 is a good indicator of natural gas volume and price uncertainty. The ratio strikes an appropriate balance in terms of the benefits of allowing dual-fuel generators the flexibility to manage their fuel, thereby incentivizing dual-fuel capability. The ratio also minimizes any potential real-time exposure to the market of generators with local market power offering on the basis of the higher-priced fuel and burning the lower-cost fuel.

The proposed changes went into effect on December 3, 2014.<sup>70</sup> However, in its order approving the proposed changes, FERC expressed concern that the 1.75 ratio was determined based on 14 months of data that included the unusually cold 2013/2014 winter months, even though the changes were proposed as permanent measures. Therefore, the ISO was directed to continue to analyze the appropriateness of the 1.75 ratio and include its analysis and recommendations as part of the *2014 Annual Markets Report*.

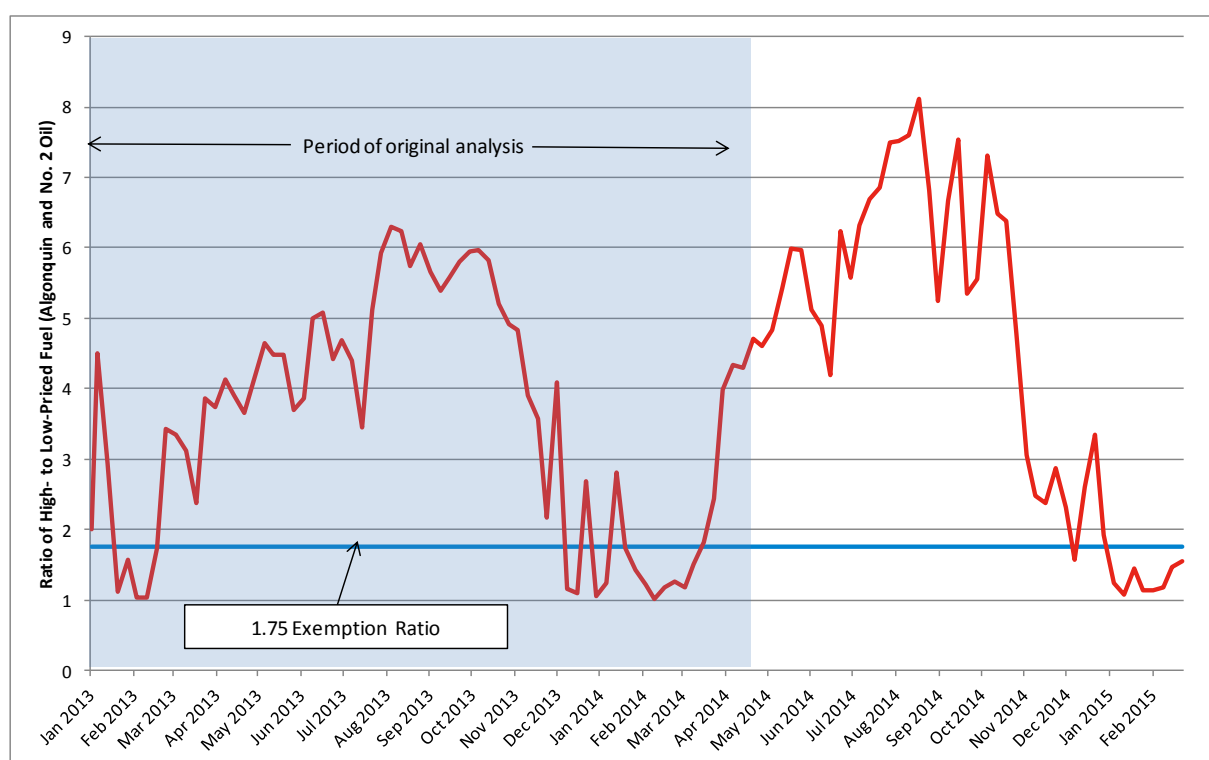
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<sup>69</sup> For example, if the day-ahead index price of natural gas is \$5/MMBtu and the day-ahead index price of No. 2 oil is \$20/MMBtu the ratio would be calculated as \$20 divided by \$5 or 4.0. On the other hand, if the day-ahead index price of natural gas is \$30/MMBtu and the day-ahead index price of No. 2 oil is \$20/MMBtu, the ratio would be calculated as \$30 divided by \$20 or 1.5.

<sup>70</sup> FERC, *Order Accepting Tariff Revisions*, 148 FERC ¶ 61,179, (September 9, 2014), [http://www.iso-ne.com/static-assets/documents/2014/09/er14-2407-000\\_9-9-14\\_order\\_accept\\_winter\\_reliability.pdf](http://www.iso-ne.com/static-assets/documents/2014/09/er14-2407-000_9-9-14_order_accept_winter_reliability.pdf).

Review of 1.75 Ratio Exemption Rule. The initial analysis that covered January 2013 to March 2014 was expanded by an additional eleven months by including FPA and DFO data through the end of February 2015.

First, it was assessed whether the relationship between natural gas and oil prices changed significantly since the original study period. Figure 2-18 shows the ratio of the higher-priced fuel to the lower-priced fuel (between Algonquin gas and No. 2 oil) on a weekly average basis. The shaded area depicts the period covered by the original analysis, which supported the 1.75 ratio. The exhibit shows that the ratio continues to drop below the 1.75 value during long parts of the winter season when gas price levels and volatility are typically at their highest. From spring 2014, the decrease in gas prices outpaced the decrease in oil prices, thereby showing a higher ratio of oil prices to gas prices compared with 2014. This component of the analysis does not indicate a fundamental change or shift in the relationship between gas and oil prices in New England, which would itself merit a reconsideration to the 1.75 ratio.



**Figure 2-18: Ratio of the higher-priced fuel to lower-priced fuel for No. 2 oil and Algonquin indices, January 1, 2013, to February 28, 2013.**

During the extended study period the implementation of EMOF on December 3, 2014 significantly changed how DFOs and FPAs are submitted. Before EMOF, FPAs and DFOs were submitted for an entire 24-hour period for a given market, day ahead or real time. This was because supply offers were constant across all 24 hours. Under EMOF, participants have the ability to submit different offers for each hour and can update these offers throughout the operating day. Consequently, FPAs and DFOs can now vary by hour and, likewise, can be updated throughout the operating day. To account for this significant design change, the analysis was separated between the pre-EMOF period (January 2013 through December 2, 2014) and the EMOF period (from December 3, 2014 through February 28, 2015).

As discussed above, between January 2013 and March 2014, approximately 67% of the DFO requests were submitted when the ratio of the higher-price fuel to the lower-price fuel was less than 1.75. The analysis considered all DFO requests below a maximum ratio of 5.5 and when the generator requesting a DFO actually operated. When including all observations (including those above 5.5), 62% of the DFO requests were received at ratios less than 1.75 (from generators that operated).

The results are similar when the analysis is extended through the implementation of EMOF, with 61% of all DFO requests received when the ratio was less than 1.75. This result is expected given that from April 2014 to December 2, 2014, the analysis added only 23 observations. See Table 2-12.

**Table 2-12**  
**Percentage of DFOs and FPAs when the Ratio is less than 1.75**

<b>Time Period</b>	<b>DFOs</b>	<b>FPAs</b>
January 2013 to March 2014 <i>Original Analysis</i>	67%	55%
January 2013 to December 2014 <i>Pre EMOF</i>	61%	32%
December 2014 to March 2015 <i>EMOF</i>	82%	70%

As observed in the original analysis, 55% of the FPA requests were submitted when the ratio of the higher- to-lower-priced fuel was less than 1.75. The results change somewhat when the study period is extended through December 2, 2014 with the share of total FPAs received when the ratio was less than 1.75 falling to 32%. This is the result of there being only two days from April 2014 through December 2, 2014 when the ratio of the higher-priced fuel to the lower-priced fuel fell below 1.75. In that that eight-month period FPAs continued to be submitted by participants accounting for 40% of the total FPA requests, albeit at a much reduced premium over the index price compared to the more volatile winter months.

On approximately 70% of the days during the EMOF period, the ratio of the higher-to-lower-priced fuel was less than 1.75. As expected, the DFO requests were heavily concentrated during this period. As discussed, under EMOF, dual-fuel generators can submit and update the fuel or fuels (in the case of fuel blending) associated with their supply offer on an hourly basis. The analysis focused on the supply offer in effect during hour ending 6:00 p.m. (a “peak” hour). Hour ending 7:00 a.m. (an “off-peak” hour) was also analyzed with similar results. Over the winter period since the start of EMOF, over 82% of the DFO requests for generators that actually operated were received when the ratio was less than 1.75.

With respect to FPAs, since the start of EMOF, 70% of the requests were submitted when the ratio of higher-to-lower-priced fuels was less than 1.75. As expected, during this period in general natural gas and oil price converged more frequently, indicating greater natural gas procurement and price uncertainty.

**Conclusion and recommendation.** In its September 9, 2014, order, FERC expressed concerns with respect to the 1.75 ratio being based on somewhat limited data, including an abnormally

cold winter period with significant price volatility, and ordered the IMM to continue to analyze the appropriateness of the ratio. As a case in point, natural gas prices in winter 2014/2015 were significantly less volatile than in 2013/2014 (see Section 2.1.3.3 and Figure 2-10). Both oil and gas prices have decreased significantly on average since the original study period and continue to converge during winter months as gas price levels pick up significantly. The number of DFO and FPA requests also continues to be concentrated when the ratio of higher-priced fuels to lower-priced fuels is low, highlighting the natural gas volume and price uncertainty that generators experience.

The analysis shows that, notwithstanding the reduction in natural gas price volatility this past winter, the 1.75 ratio continues to be a reasonable and appropriate indicator of oil and natural gas price convergence. Consequently, the 1.75 ratio should remain the threshold for exempting dual-fuel units from the requirement to justify and provide documentation on the use of the higher-priced fuel. In addition, the IMM will continue to assess this ratio on the basis of how generators are using the provision and on prevailing market conditions.

## 2.2 Real-Time Operating Reserves

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This section summarizes the performance of the real-time operating reserves markets. Operating Reserve is capacity available to the ISO that can be converted into energy within a short interval so that the system can be operated reliably in the event of unforeseen incidents such as the loss of major elements of generation or transmission equipment. In real-time, the dispatch of resources to meet the energy and operating reserve requirements is jointly optimized. In the presence of a binding reserve constraint, the real-time operating reserve price is equal to the opportunity cost of the resource not dispatched for energy to satisfy the operating reserve requirement, capped by the Reserve Constraint Penalty Factor (RCPF).<sup>71</sup>

### 2.2.1 Real-Time Operating Reserve Types and Dispatch

The ISO's operating reserve requirements are described in Operating Procedure No. 8 (OP 8), *Operating Reserve and Regulation*.<sup>72</sup> As specified in OP 8, the ISO must maintain a sufficient amount of operating reserves for the system as a whole and for identified transmission-import-constrained areas to be able to recover from the loss of the first-largest contingency within 10 minutes. The ISO has real-time operating reserve requirements (in MW) for the following categories (or products):

- **10-minute spinning reserve (TMSR):** This is the highest-quality operating reserve product. TMSR is provided by on-line resources able to increase output within 10 minutes, allowing the system a high degree of certainty for being able to recover quickly from a significant system contingency.
- **10-minute non-spinning reserve (TMNSR):** This is the second-highest quality operating reserve product. TMNSR is provided by off-line units that require a successful startup (i.e., electrically synchronize to the system and increase output within 10

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<sup>71</sup> RCPFs are administratively set limits on redispatch costs the system will incur to meet reserve constraints. Each type of reserve constraint has a corresponding RCPF. In December 2014, the RCPF for 30-minute operating reserve was increased to \$1,000/MWh from \$500/MWh, and the RCPF for 10-minute non-spinning reserve was increased to \$1,500/MWh from \$850/MWh.

<sup>72</sup> See Operating Procedure No. 8, *Operating Reserves and Regulation* (May 2, 2014), [http://www.iso-ne.com/static-assets/documents/rules\\_proceeds/operating/isone/op8/op8\\_rto\\_final.pdf](http://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op8/op8_rto_final.pdf)

minutes) to ensure that needed operating reserves actually will be available in response to a contingency.<sup>73</sup>

- **Thirty-minute operating reserve (TMOR):** This is the lowest-quality operating reserve provided by less-flexible resources within the system (i.e., on-line or off-line resources that can either increase output within 30 minutes or electrically synchronize to the system and increase output within 30 minutes in response to a contingency).

TMSR and TMNSR can be used to meet the TMOR requirements but not the other way around.

In the Real-Time Energy Market, the dispatch algorithm optimizes the use of generating resources to meet energy and operating reserve requirements while respecting transmission constraints. The dispatch uses each resource's real-time energy offer; there are no separate real-time operating reserve offers. Other features of the dispatch algorithm include the following:

- In the presence of a binding operating reserve constraint, the system dispatch may reduce the output of an otherwise economic unit in the energy market to create operating reserves on the system. When this occurs, the opportunity cost of altering the dispatch determines the market-clearing price for the operating reserve product.
- The market-clearing software will not redispatch resources to meet operating reserves at any price. When the redispatch costs exceed the RCPF, the price will be set equal to the penalty factor and the market software will not continue redispatching resources to meet operating reserves.<sup>74</sup>
- The market software optimizes the use of local transmission interfaces to minimize the cost of satisfying all operating reserve and energy requirements in the region.

To ensure that the incentives for providing the individual operating reserve products are correct, the market's prices maintain an ordinal ranking consistent with the quality of the operating reserve provided, as follows:

$$\text{TMSR} \geq \text{TMNSR} \geq \text{TMOR}$$

The price of higher-quality operating reserve products must be at least as high as the price of lower-quality products. For example, if the ISO alters the dispatch to provide TMOR at a cost of \$40/MWh, the prices for TMSR and TMNSR both must equal or be greater than \$40/MWh.<sup>75</sup>

### 2.2.2 Real-Time Operating Reserve Outcomes

Average annual operating reserve prices in dispatch intervals with positive operating reserve prices decreased for all products in 2014 compared with 2013. While the number of dispatch

<sup>73</sup> *Ten-minute non-spinning reserve* also is called 10-minute nonsynchronized reserve.

<sup>74</sup> When an RCPF is reached and the Real-Time Energy Market's optimization software stops redispatching resources to satisfy the reserve requirement, the ISO will manually redispatch resources to obtain the needed reserve.

<sup>75</sup> This price "cascading" occurs when a binding operating reserve constraint exists and higher-quality products obtain the same pricing as lower-quality operating reserve products. Because TMSR is the highest-quality product, TMNSR is the second-highest, and TMOR is the lowest-quality operating reserve product, the TMSR price is always greater than or equal to the TMNSR and TMOR prices, and the TMNSR price is always greater than or equal to the TMOR price.

intervals with positive pricing for TMSR increased, the number of dispatch intervals with positive TMNSR and TMOR prices decreased. Although the percentage change in the number of dispatch intervals with positive prices is significant, the absolute number of dispatch intervals with positive prices was still low in 2014. See Table 2-13. Note that large percentage changes in average operating reserve prices seasonally and year-over-year are not uncommon. Fuel-price variation, load forecast errors, unexpected changes in system conditions, and many other factors can influence the frequency and level of operating reserves prices. However, while the change in average price might be large, the low frequency of operating reserve pricing results in very small overall market settlement impacts, as demonstrated by the payment data shown in the table.

**Table 2-13**  
**Average Operating Reserve Prices and Frequencies for Intervals with Positive Prices,**  
**2013 to 2014<sup>(a)</sup>**

Product	Average Annual Price			Frequency		
	2013	2014	% Change	2013	2014	% Change
	(\$/MW/5-Min. Interval)			(% of Total 5-Min. Intervals)		
<b>10-minute spinning reserve (TMSR)</b>	92.44	40.94	<b>-55.7%</b>	3.2%	6.0%	<b>89.3%</b>
<b>10-minute non-spinning reserve (TMNSR)</b>	212.34	187.81	<b>-11.6%</b>	1.1%	0.9%	<b>-25.4%</b>
<b>30-minute operating reserve (TMOR)</b>	202.02	180.61	<b>-10.6%</b>	1.1%	0.9%	<b>-24.1%</b>

(a) Prices are presented for the Rest-of-System reserve zone. Average operating reserve prices are based on the preliminary prices and would not include any ex-post pricing adjustments. Ex-post adjustments to 5-minute operating reserve prices are not available.

Operating reserve pricing occurs when the system must redispatch resources away from the lowest-cost solution for satisfying energy requirements and incur additional costs to meet the system operating reserve requirement. When this happens, the operating reserve price is the opportunity cost of the least expensive resource whose energy output is reduced to provide operating reserves during redispatch. As a practical matter, the cost incurred to redispatch on-line 10-minute operating reserve assets is lower, on average, than the cost incurred to redispatch less flexible resources to provide the 30-minute operating reserves.

Table 2-13 shows that positive nonzero prices for TMSR occurred in approximately six times as many intervals as positive pricing for TMOR, but prices, on average, were significantly lower than for the other products. These low average prices are the result of low prices during the intervals when only the TMSR pricing occurred, and all other products were priced at \$0/MWh. The TMSR interval price was relatively low, reflecting a lower average cost after redispatch.

Table 2-14 compares the frequency and average prices (during nonzero pricing intervals) across operating reserve zones for 2014. The frequency of binding constraints across zones was highly consistent in 2014. Only the NEMA/Boston zone experienced binding constraints and prices that were different from the Rest-of-System zone. NEMA/Boston had a higher frequency for all operating reserve products, higher average prices for TMSR, and reduced average prices for TMNSR and TMOR compared with the other zones.

**Table 2-14**  
**Real-Time Operating Reserve Clearing Prices for Nonzero Price Intervals, 2014<sup>(a)</sup>**

Product	Operating Reserve Zone	Price (\$/MW/5-Minute Intervals)	Frequency (% of 5-Minute Intervals)
TMSR	Connecticut	40.94	6.02%
	NEMA/Boston	43.15	6.26%
	Rest-of-System	40.94	6.02%
	Southwest Connecticut	40.94	6.02%
TMNSR	Connecticut	187.81	0.85%
	NEMA/Boston	167.67	1.09%
	Rest-of-System	187.81	0.85%
	Southwest Connecticut	187.81	0.85%
TMOR	Connecticut	180.61	0.85%
	NEMA/Boston	162.07	1.09%
	Rest-of-System	180.61	0.85%
	Southwest Connecticut	180.61	0.85%

(a) Average operating reserve prices are based on the preliminary prices and would not include any ex-post pricing adjustments. Ex-post adjustments to 5-minute reserve prices are not available.

Table 2-15 summarizes operating reserve payments for 2012 to 2014. The payments declined from 2013 to 2014. Except for NEMA/Boston TMOR payments, operating reserve payments decreased across all products and regions, with the largest decrease occurring for systemwide TMNSR.

**Table 2-15**  
**Operating Real-Time Reserve Payments, 2012 to 2014 (\$ Millions)**

Year	Systemwide TMSR	Systemwide TMNSR	Systemwide TMOR	SWCT TMOR	CT TMOR	NEMA/Boston TMOR	Total
<b>2012</b>	11.4	12.2	1.4	3.2	1.2	0.4	<b>29.8</b>
<b>2013</b>	18.0	26.1	2.9	4.9	1.4	0.7	<b>54.0</b>
<b>2014</b>	14.4	17.4	1.8	3.3	0.6	1.1	<b>38.6</b>

In 2014, the total real-time operating reserve payments were \$38.6 million. In 2013, real-time operating reserve payments totaled \$54.0 million, a significant increase from \$29.8 million in 2012. As discussed in the *2013 Annual Markets Report*, the increase in payments between 2012 and 2013 resulted from several changes in operating reserve programs.<sup>76</sup> Although operating reserve payment totals may change significantly on a percentage basis from year to year as a result of changes in operating reserve programs, fuel prices, and system conditions, total payments for operating reserves are relatively small, compared with overall energy market and capacity market payments.

<sup>76</sup> While changes in the ISO's reserve markets in 2013 and 2014 have increased payments, large year-to-year variation is not unusual for reserve payments. Significant levels of reserve payments are incurred during system

With respect to the implementation of pay-for-performance (see Section 3.4.3.3), the ISO made a compliance filing on July 14, 2014, in response to a FERC order requiring the ISO to increase Reserve Constraint Penalty Factors for 30-minute operating reserves, from \$500/MWh to \$1,000/MWh, and 10-Minute non-spinning reserves, from \$850/MWh to \$1,500/MWh. That change was implemented on December 3, 2014.

## 2.3 Regulation Market

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This section presents data about the participation, outcomes, and competitiveness of the Regulation Market in 2014. The Regulation Market was competitive in 2014.

The Regulation Market is the mechanism for selecting and paying resources needed to balance supply levels with the second-to-second variations in electric power demand and to assist in maintaining the frequency of the entire Eastern Interconnection.<sup>77</sup> The objective of the Regulation Market is to acquire adequate resources such that the ISO meets NERC's *Real Power Balancing Control Performance Standard* (BAL-001-0).<sup>78</sup> NERC establishes technical standards, known as Control Performance Standards, for evaluating area control error (unscheduled power flows) between balancing authority areas (e.g., between New England and New York). For New England, NERC has set the Control Performance Standard 2 (CPS 2) at 90%.<sup>79</sup>

The regulation clearing price (RCP) is calculated in real time and is based on the regulation offer of the highest-priced generator providing the service. Compensation to generators that provide regulation includes a regulation capacity payment, a service payment, and a make-whole payment.<sup>80</sup> Unit-specific opportunity cost payments are included as a component of the regulation clearing price.

### 2.3.1 Regulation Pricing

In 2014, the average regulation price of \$19.06/MWh was 63% higher than the 2013 price of \$11.68/MWh. See Table 2-16.

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contingency periods (such as the loss of a large generator), extreme weather fluctuations, and other events that require the conversion of available reserves into electric energy or that otherwise limit the reserves available to the system. The frequency and magnitude of these events vary each year.

<sup>77</sup> The *Eastern Interconnection* consists of the interconnected transmission and distribution infrastructure that synchronously operates east of the Rocky Mountains, excluding the portion of the system located in the Electric Reliability Council of Texas, Newfoundland, Labrador, and Québec.

<sup>78</sup> This NERC standard (effective April 1, 2014) can be accessed at <http://www.nerc.com/pa/Stand/Pages/AllReliabilityStandards.aspx?jurisdiction=United States>. Additional information on NERC requirements is available at <http://www.nerc.com> (2013).

<sup>79</sup> The primary measure for evaluating control performance, (CPS 2), is as follows:

*Each balancing authority shall operate such that its average area control error (ACE) for at least 90% of clock-10-minute periods (six nonoverlapping periods per hour) during a calendar month is within a specified limit, referred to as L<sub>10</sub>.*

More information on NERC's Control Performance Standard 2 is available at [http://www.nerc.com/files/Reliability\\_Standards\\_Complete\\_Set.pdf](http://www.nerc.com/files/Reliability_Standards_Complete_Set.pdf) (Resource and Demand Balancing; BAL).

<sup>80</sup> These make-whole payments ensure that units providing regulation service are compensated for the capacity cost, service cost, and unit-specific opportunity cost.

**Table 2-16**  
**Regulation Prices (\$/MWh) and Total Payment (Million \$), 2012 to 2014**

Year	Minimum Price (\$/MWh)	Average Price (\$/MWh)	Maximum Price (\$/MWh)	Total Payment (Million \$)
2012	0	6.75	70.33	11.6
2013	0	11.68	692.08	20.4
2014	0	19.06	1,407.43	28.8

Payments to resources providing regulation service totaled \$28.8 million in 2014, a 41% increase from the total regulation payments in 2013.

An interim Regulation Market solution was implemented on July 1, 2013, to address the major elements of FERC Order 755.<sup>81</sup> The interim solution incorporates regulation opportunity costs into the uniform regulation clearing price. Because a regulation unit's opportunity cost is affected by the Real-Time Energy Market price, the volatility of the regulation clearing price is closely related to the Real-Time Energy Market price. The maximum regulation price observed in 2014 of \$1,407.43/MWh is consistent with the real-time price of \$1,116.63/MWh in the prior hour.

The market efficiency and competitiveness are not affected by the interim solution. However, the increase of total regulation payments is largely attributable to the market rule change. The increase in the overall natural gas price, in particular in the first quarter of 2014, has also contributed to the increase in regulation capacity and service costs and therefore the total regulation payment.

### 2.3.2 Requirements and Performance

New England's hourly regulation requirement has been decreasing steadily from an average requirement of 181 MW in 2002, to below 60 MW in 2013 and 2014. The average hourly regulation requirement was virtually unchanged from 59.51 MW in 2013 to 59.52 MW in 2014. The regulation requirement in New England varies throughout the day and typically is highest in the early morning and the late evening. The higher regulation requirement during these hours is the result of load variability.

The ISO seeks to maintain NERC Control Performance Standard 2 within the range of 90% to 100%. The ISO has continually met its more stringent, self-imposed CPS 2 targets. For 2014, the ISO achieved a minimum value of 91.5% and a maximum value of 96.7%.

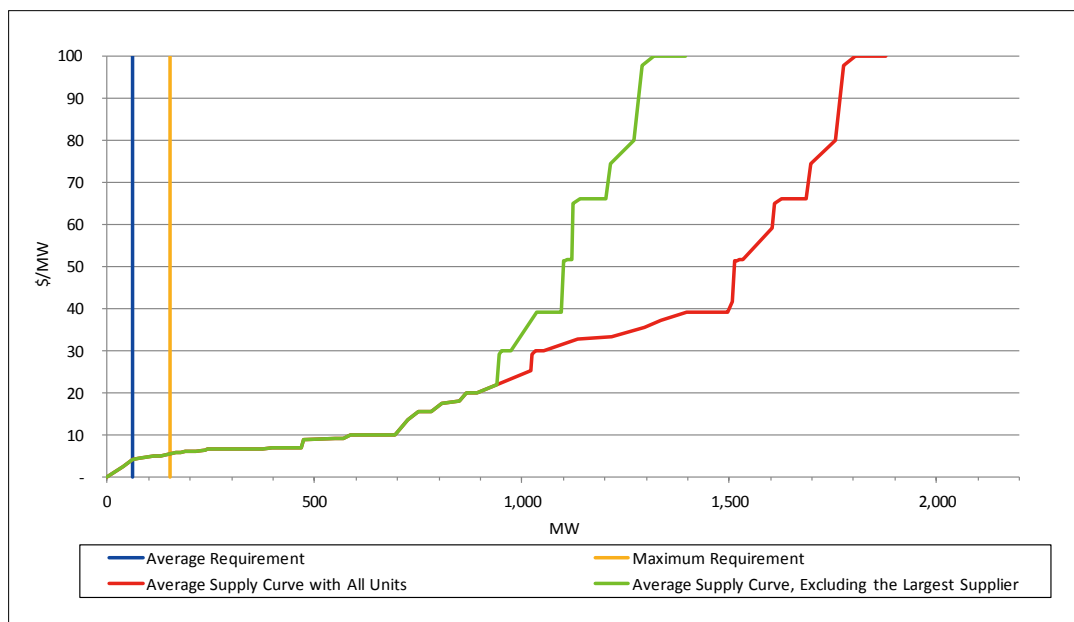
### 2.3.3 Competitiveness of the Regulation Market

The competitiveness of the Regulation Market was reviewed using demand and supply curves and the results of the hourly average residual supply index for the Regulation Market (see Section 2.3). Both these measures examine the market structure and resource abundance. The

<sup>81</sup> *ISO New England Inc. and NEPOOL, Regulation Market Opportunity Cost Change*, Docket No. ER13-1259-000, FERC filing (April 11, 2013), [http://www.iso-ne.com/regulatory/ferc/filings/2013/apr/er13-1259-000\\_4-11-2013\\_reg\\_mkt\\_opp\\_cost\\_chg.pdf](http://www.iso-ne.com/regulatory/ferc/filings/2013/apr/er13-1259-000_4-11-2013_reg_mkt_opp_cost_chg.pdf). FERC, *Regulation Market Opportunity Cost Change*, Docket No. ER13-1259-000, letter order (June 27, 2013), [http://www.iso-ne.com/regulatory/ferc/orders/2013/jun/er13-1259-000\\_6-17-13\\_ltr\\_order\\_accept\\_reg\\_mrkt\\_rev.pdf](http://www.iso-ne.com/regulatory/ferc/orders/2013/jun/er13-1259-000_6-17-13_ltr_order_accept_reg_mrkt_rev.pdf).

abundance of regulation resources implies that market participants have little opportunity to engage in economic or physical withholding. The Regulation Market was competitive in 2014.

Figure 2-19 shows the average and maximum regulation requirement (demand) and the average regulation supply for 2014 with and without the largest supplier. Because both the average and maximum regulation requirement lie to the far left end of the regulation supply curve, regulation prices do not change significantly with changes in regulation supply. If the largest supplier were removed from the Regulation Market, the impact on regulation prices would be very small. Consequently, no Regulation Market supplier can profitably withhold its resource(s) from the market.



**Figure 2-19: Regulation Market demand, average, and maximum requirements and supply curves with and without the largest supplier, 2014 (MW and \$/MW).**

Competitive conditions, along with changes in the regulation requirement, can vary during the day because of load variability and supply uncertainty. As shown in Figure 2-20, the regulation requirement and RSI are inversely correlated. In 2014, the lowest hourly average RSI did not fall below 1,000%, implying that, on average, the system has the capability to serve 10 times the regulation requirement without the largest regulation supplier, even in the hours with the greatest regulation requirement.

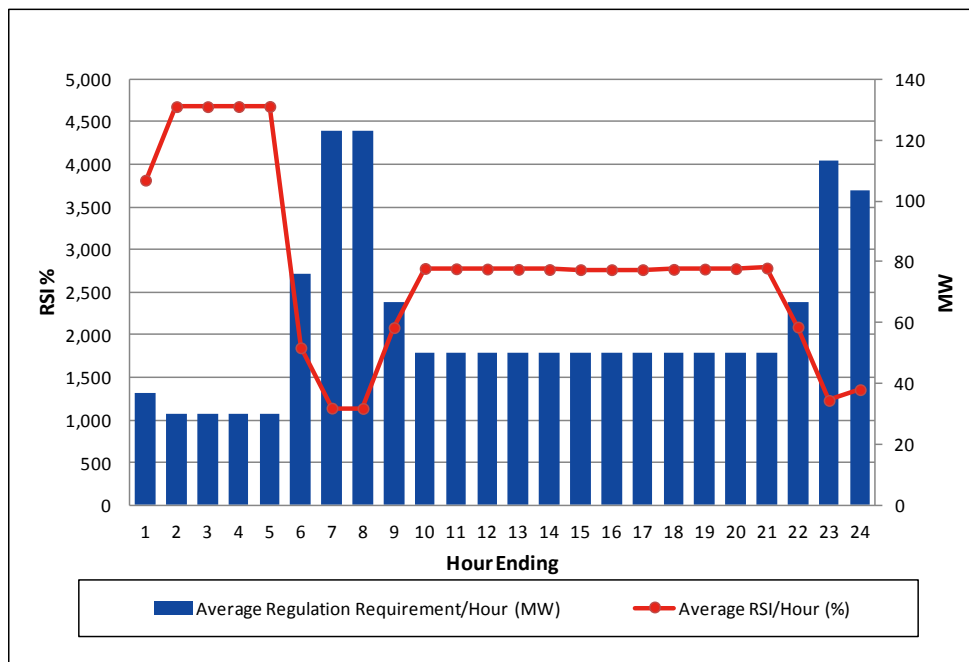


Figure 2-20: Average regulation requirement and residual supply index per hour, 2014.

## Section 3

### Forward Markets

This section describes the 2014 outcomes and recommendation regarding the ISO's forward markets, including the Day-Ahead Energy Market, Financial Transmission Rights, the Forward Reserve Market, and the Forward Capacity Market.

#### 3.1 Day-Ahead Energy Market

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This section provides information on the outcomes of the ISO's Day-Ahead Energy Market for 2014.

The day-ahead market allows buyers and suppliers of electricity to make purchase and sale decisions the day before the operating day. Load-serving entities (LSEs) acting on behalf of end-users may submit energy demand schedules, which express their willingness to buy a quantity of electricity at prescribed prices. Many suppliers have the option to submit day-ahead supply offers, which express their willingness to sell a quantity of electricity at prescribed prices. Suppliers with a capacity supply obligation (CSO) (see Section 3.4) must offer to sell electricity into the day-ahead market at a quantity at least equal to its CSO. In addition, as described in Section 3.1.4, any market participant may submit *virtual* demand bids (i.e., decrement bids) or supply offers (increment offers) into the day-ahead market. As the name implies, virtual demand bids and supply offers do not require a market participant to have physical load or supply.

Generator offers and virtual bids and offers are submitted at a nodal level (see Section 2.1) and indicate the willingness to buy or sell a quantity of electric energy in the day-ahead market at that location. The ISO uses a clearing algorithm that selects bids and offers to maximize social welfare, subject to transmission constraints. The day-ahead market results are posted no later than 1:30 p.m. the day before the operating day. Resources that clear in the Day-Ahead Energy Market but do not recover their as-bid costs from the market receive day-ahead Net Commitment-Period Compensation.

##### 3.1.1 Day-Ahead Pricing

The average day-ahead Hub price in 2014 was \$64.57/MWh. This price is consistent with observed market conditions, including natural gas prices, load levels, and available supply. Price differences among the load zones primarily stemmed from marginal losses, with little congestion at the zonal level. Congestion was typically restricted to smaller, more transient load pockets that formed when transmission or generation elements were out of service.

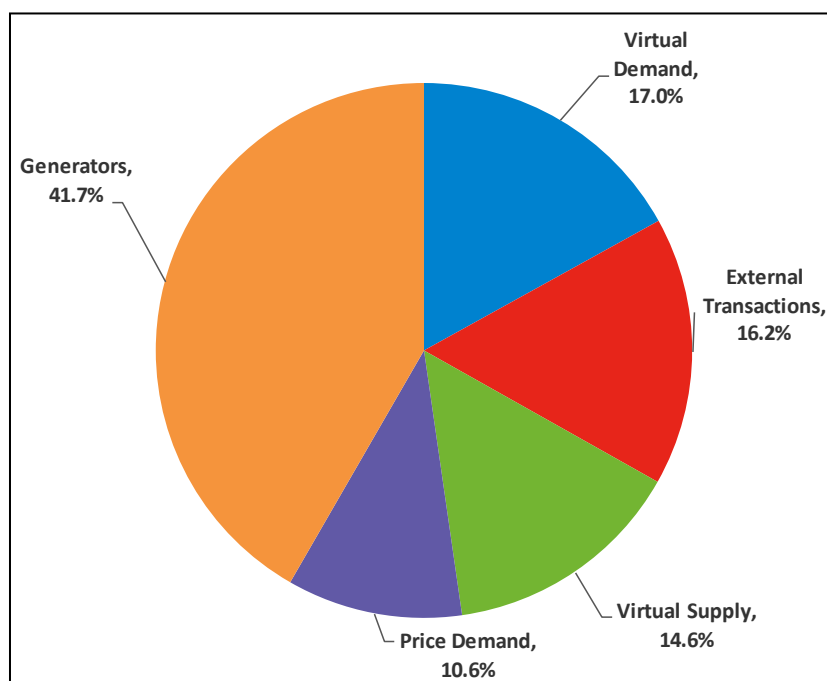
The Maine load zone continues to have the lowest average price in the region. The average LMPs in the Maine load zone were \$2.61/MWh lower than the Hub price, largely because the marginal loss component of the LMPs in Maine were lower than those components at the Hub. The average LMPs in the Northeastern Massachusetts (NEMA), Southeastern Massachusetts (SEMA), and Rhode Island load zones were \$0.41, \$0.14, and \$0.41/MWh greater, respectively, than the average Hub price, largely because the congestion components of the LMP in these zones were higher than those components at the Hub. See Table 3-1.

**Table 3-1**  
**Simple Average Day-Ahead Hub and Load-Zone Prices for 2012, 2013, and 2014 (\$/MWh)**

Location/ Load Zone	2012	2013	2014
Hub	36.08	56.42	64.57
Maine	35.90	54.48	61.95
New Hampshire	35.92	55.98	64.12
Vermont	36.25	55.36	63.81
Connecticut	36.77	55.43	64.09
Rhode Island	36.24	57.79	64.97
SEMA	36.09	57.02	64.71
WCMA	36.98	56.37	64.66
NEMA	36.15	56.90	64.98

### 3.1.2 Price Setting in the Day-Ahead Market

As shown in Figure 3-1, in the day-ahead market, generators set price approximately 42% of the time in 2014, and virtual transactions (see Section 3.1.4) set price approximately 32% of the time. These percentages are similar to 2013, when generators set price approximately 42% of the time, and virtual transactions set price approximately 33% of the time.



**Figure 3-1: Percentage of price setting in the day-ahead market, 2014.**

### 3.1.3 Day-Ahead Demand for Electric Energy

*Fixed demand* (i.e., load that LSEs purchase at any price) increased by 3,284 GWh in 2014 from 2013, which increased fixed demand as a percentage of total demand cleared in the day-ahead market from 70% in 2013 to 74% in 2014. Virtual demand and exports have decreased in both

volume and as a percentage of total cleared demand over the most recent three-year period (see Section 3.1.4 and Section 2.1.3.5). Price-sensitive demand's share of total day-ahead cleared demand declined from 25% in 2013 to 23% in 2014. See Figure 3-2.

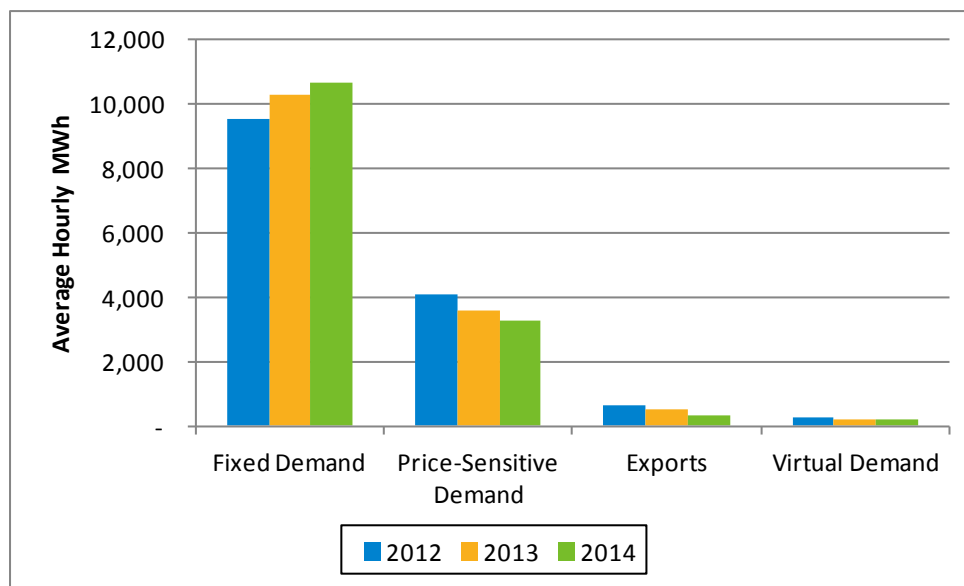


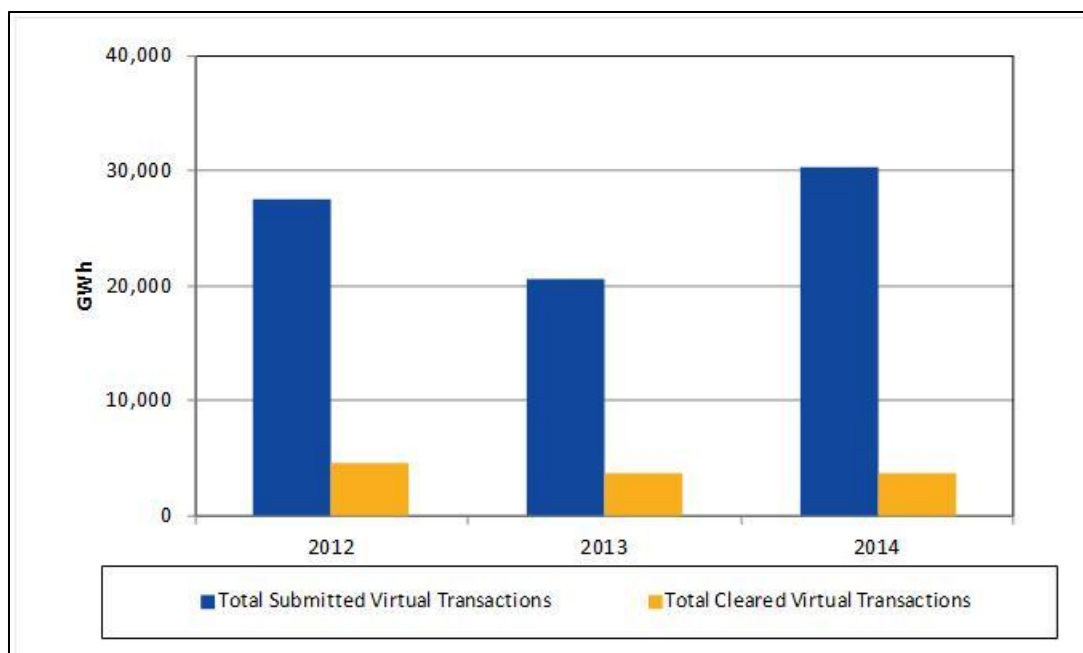
Figure 3-2: Hourly average day-ahead demand cleared, 2012 to 2014 (average MWh).

### 3.1.4 Virtual Transactions

Virtual transactions allow participants to buy or sell power in the Day-Ahead Energy Market without owning physical supply or load. Virtual transactions help converge day-ahead and real-time prices through arbitrage.

Cleared virtual supply offers (*increments*) in the day-ahead market and at a particular location in a certain hour, create a financial obligation for the participant to buy back the bid quantity at the real-time market price at that location in that hour. Cleared virtual demand bids (*decrements*) in the day-ahead market, create a similar financial obligation to sell the bid quantity at the real-time market price. The difference between the hourly day-ahead and real-time LMPs at the location at which the offer or bid clears determines the financial outcome for a particular participant.

*Submitted and Cleared Virtual Transactions.* In 2014, the volume of cleared virtual transactions (in GWh) were slightly lower than 2013, while submitted virtual transactions increased from the previous year. Cleared virtual transactions had decreased significantly in both 2012 and 2013. Together, the volume of submitted virtual demand bids and virtual supply offers totaled 30,305 GWh in 2014. The volume of submitted virtual transactions increased in 2014, the result of three participants' increased activity at external nodes. Most of the virtual transactions submitted by the participants to the external nodes did not clear. In fact, if the activity of these three participants is removed from the total volume, submitted virtual transactions only increased by 4% in 2014. Cleared virtual transactions totaled 3,794 GWh, a 0.4% decrease from 3,809 GWh in 2013. See Figure 3-3.



**Figure 3-3: Total submitted and cleared virtual transactions, 2012 to 2014 (GWh).**

After accounting for the bidding activity of three participants at external nodes, the volume of trading for virtual transactions increased only modestly in 2014. The overall decline of cleared virtual transactions in the long run continues to imply that the effects of high and uncertain transaction costs observed continue to persist, as documented in past Annual Markets Reports.

We continue to support the recommendation that the ISO should revise the market rules so that real-time Net Commitment-Period Compensation charges are not allocated to virtual transactions.

In 2014, the ISO proposed market rule changes to strengthen the incentive for load serving entities, exporters and virtual demand bidders to buy energy in the day-ahead energy market. The proposed rule changes would have excluded positive load deviations from real-time first contingency NCPC charges. However, stakeholders did not support the proposed change and the ISO opted not to file the proposed change with FERC. The ISO plans to commence a stakeholder process in 2015 to address the NCPC cost allocation issues in general including the method used to allocate first-contingency NCPC charges to both virtual demand and supply deviations.

### **3.1.5 Day-Ahead Supply and Self-Scheduling of Electric Energy**

Market participants have the option to self-schedule their generation resources in the day-ahead market. By self-scheduling, the market participant becomes a price taker, essentially offering to sell a specified quantity at the prevailing day-ahead price. Self-scheduling behavior has been consistent over the past several years.

Day-ahead self-schedule volumes decreased by 336 GWh from 2013 to 2014. Day-ahead self-schedule volumes in 2013 and 2014 accounted for 55% of total volumes. Economic supply offers decreased to 25% of the total, slightly lower than the levels observed in 2013. Virtual supply slightly increased in both volume and as a percentage of total cleared supply. Import

volumes increased volume over the past two years and comprised 18% of total cleared supply in 2014. See Figure 3-4.

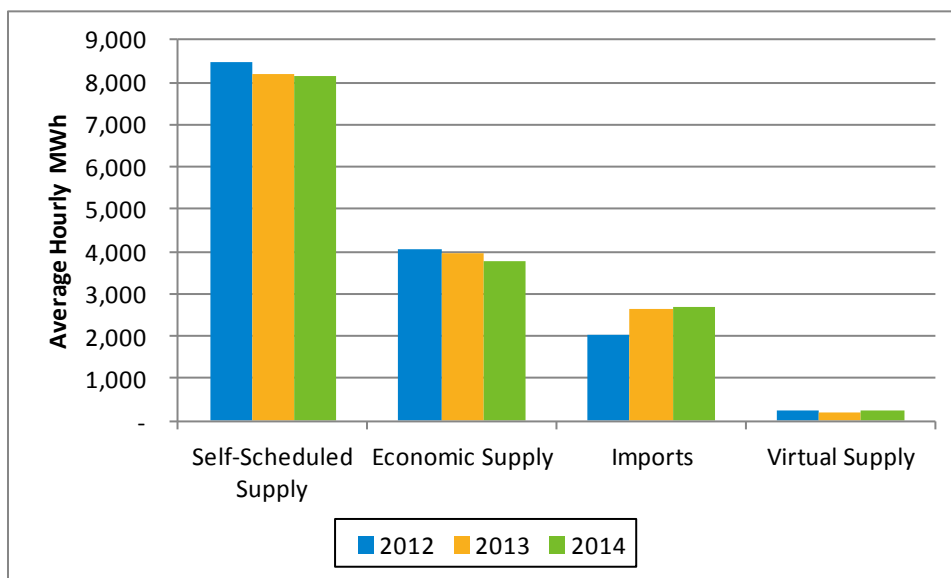


Figure 3-4: Hourly average day-ahead supply cleared, 2012 to 2014 (average MWh).

### 3.1.6 Relationship between Day-Ahead Energy Prices and Other Market Factors

This section compares day-ahead demand with real-time demand and analyzes the bidding behavior of load-serving entities in the day-ahead and real-time markets.

#### 3.1.6.1 Comparison of Day-Ahead Demand with Real-Time Demand

The quantity of demand clearing in the day-ahead market is one of the factors that can have an impact on the amount of supplemental (balancing) commitments made in the reserve adequacy analysis, referred to as RAA commitments. On average, the percentage of demand purchased in the day-ahead market is fairly constant from month to month. The annual percentage of day-ahead demand cleared as a percentage of real-time demand has increased slightly, from 94% in 2013 to 96% in 2014.<sup>82</sup>

### 3.1.7 Day-Ahead Energy Market Lerner Index

This section analyzes market competitiveness and shows that the Day-Ahead Energy Market was competitive in 2014.

In this analysis, the *Lerner Index* estimates the component of the price that is a consequence of offers above cost. The Lerner Index measures price distortion. Since price is the principle means of coordinating short-run production and consumption decisions, when either profits or prices are distorted as a result of the exercise of uncompetitive behavior (i.e., bids above marginal cost), short- and long-term resource-allocation decisions can be distorted and increase overall

<sup>82</sup> The energy purchased in the day-ahead market is a percentage of actual energy consumption in New England and is calculated as follows:

$$\text{Day-Ahead Demand Cleared as a Percentage of Real-Time Load} = \frac{(\text{Cleared Fixed Demand Bids} + \text{Cleared Price-Sensitive Demand Bids} + \text{Cleared Virtual Demand Bids} - \text{Cleared Virtual Supply Offers})}{(\text{Net Energy for Load})}$$

costs. In a perfectly competitive market, all participants' offers would equal their marginal costs. The analysis shows that competition among suppliers limited their ability to offer substantially above marginal cost.

To calculate the Lerner Index, the Day-Ahead Energy Market clearing was simulated under two scenarios:<sup>83</sup>

- Scenario 1 is an *offer case* that uses the actual offers market participants submitted for the Day-Ahead Energy Market.
- Scenario 2 is a *marginal cost case* that assumes that all market participants offer at an estimate of the participant's short-run marginal cost.

The percentage difference between the annual generation-weighted average LMPs for the offer case and the marginal cost case simulations was then calculated. The Lerner Index ( $L$ ) is calculated as follows:

$$L = \frac{LMP_O - LMP_{MC}}{LMP_O} \times 100$$

Where:

$LMP_O$  is the annual generation-weighted average LMP for the offer case.

$LMP_{MC}$  is the annual generation-weighted average LMP for the marginal cost case.

A larger  $L$  means that a larger component of the price is the result of marginal offers above the participant's marginal cost. A change in an inframarginal resource's marginal cost or market share does not change the Lerner Index; only the offers of marginal units have an impact on this measure.

For 2014, offers above marginal cost added no more than approximately 9% to the Day-Ahead Energy Market price. Table 3-2 shows the summary results of the Lerner Index. These results are within normal year-to-year system and modeling variability for this measure.<sup>84</sup>

**Table 3-2**  
**Lerner Index, 2012 to 2014 (%)**

Year	Lerner Index
2012	9.9
2013	4.3
2014	9.0

<sup>83</sup> The IMM uses the PROBE, or "Portfolio Ownership and Bid Evaluation," simulation model for this analysis. The software simulates the day-ahead LMP-based market clearing. See <http://www.power-gem.com/PROBE.htm>.

<sup>84</sup> Note that the IMM's estimates of marginal cost may understate or overstate actual costs, and the simulations are subject to modeling error.

To put these results in context, in constrained areas, the offer-mitigation rules allow participants to submit offers the lesser of \$25/MWh or 50% above reference levels without review. In unconstrained areas, the rules allow offers that are the lesser of \$100/MWh or 300% above reference levels without review.

The size of these threshold limits allow for inaccuracies due to estimation errors and simplifications that must be made as part of the method of estimating each resource's marginal costs. If the market were not competitive, the profit-maximizing strategy, at least some of the time, would be for participants to submit offers \$25/MWh to \$100/MWh above their marginal costs, depending on system conditions. If this strategy were viable, instead of the marginal resources adding 9% on average to their offers, the market would observe a much larger adder above marginal cost on the typical offer.

### 3.2 Financial Transmission Rights

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This section summarizes the 2014 activities and results associated with Financial Transmission Rights (FTRs).

*Financial Transmission Rights* allow participants to hedge transmission congestion costs by providing a financial instrument to arbitrage differences between expected and actual day-ahead congestion. The FTR instrument entitles the holder to receive, over a monthly or annual period, a stream of revenues (or obligates it to pay a stream of charges) that arise when the transmission grid is congested in the Day-Ahead Energy Market. The FTR payoff is based on the difference between the day-ahead congestion components of the hourly LMPs at each of the two pricing locations (nodes) that define the FTR and its megawatt quantity acquired in the FTR auctions.<sup>85</sup> Participants can acquire FTRs for any path on the system defined by two pricing locations. The origin location of an FTR is called the *source* point, and the FTR delivery location is called the *sink* point. The price of a particular FTR is determined by the difference between the prices at the sink location and the source location in the FTR auction.

Annual FTRs are offered in a single auction, and additional monthly FTRs are offered before each month during the year. The annual FTR auction makes available up to 50% of the transmission system capability expected to be in service during the year. In the monthly auctions, up to 95% of the expected transmission capability for the month is available.<sup>86</sup> The total volume of FTRs transacted in each auction is a function of the offers and bids submitted subject to the transmission limits modeled.

Participants buy or sell FTRs for different reasons. Participants with physical generation or load may choose to use FTRs as a tool for managing congestion risk associated with delivery obligations. A load-serving entity may choose to purchase FTRs to protect against transmission costs associated with congestion on particular paths or in particular zones where its load is served. Congestion-paying LSEs receive *Auction Revenue Rights* (ARRs), which are rights to

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<sup>85</sup> The minimum quantity for an FTR is 0.1 MW.

<sup>86</sup> The remaining 5% is reserved to account for unplanned outages.

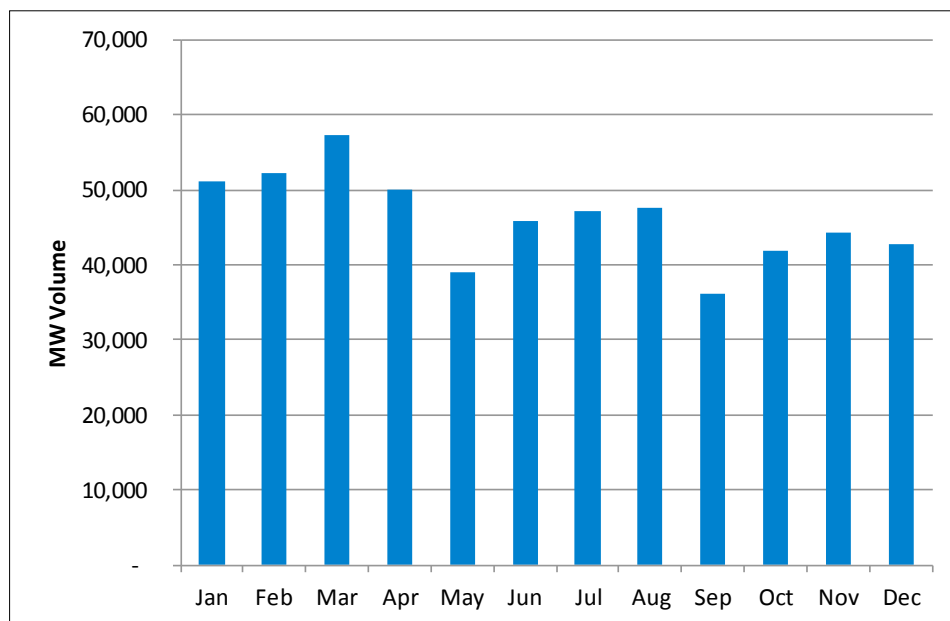
receive a portion of FTR auction revenues. Revenues collected from the auctions are distributed back to congestion-paying LSEs.<sup>87</sup>

Financial participants who have no physical obligations in the ISO markets may also buy and sell FTRs. These participants attempt to profit by arbitraging the difference between the prevailing FTR price and the FTR's true value as reflected in its payout. These activities add liquidity to the FTR auctions. Participation by financial participants can increase or decrease the total auction revenues. FTR paths that clear with a positive price result in increased auction revenues, while paths with negative clearing prices result in decreased auction revenues. Efficient auction outcomes are those that result in average path prices that have a risk-adjusted profit of zero.

### 3.2.1 FTR Auction Results

Forty-seven participants took part in at least one of the 13 FTR auctions in 2014, down from the 48 participants who took part in at least one of the FTR auctions in 2013.

The total megawatts bought and sold in the 2014 FTR auctions, regardless of directional flow, were 604,391 MW. Of this total, the percentage of megawatts associated with counterflow positions was 20%, up from 16% in 2013. Counterflow FTR positions free up transmission capacity that otherwise would have been constrained. Figure 3-5 shows the volume of megawatts bought and sold in each monthly FTR auction in 2014.



**Figure 3-5: FTR monthly volumes, 2014 (MW).**

**Note:** All megawatts, whether prevailing flow or counterflow, are treated as positive megawatts in this figure.

<sup>87</sup> ISO New England Inc. *Transmission, Markets, and Services Tariff*, Section III.5.2, *Market Rule 1 "Transmission Congestion Credit Calculation"* (February 16, 2015), [http://www.iso-ne.com/static-assets/documents/2014/12/mr1\\_sec\\_1\\_12.pdf](http://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf).

The total net revenue from the 12 monthly auctions and the single annual auction was \$31.8 million, a 58% increase from 2013.<sup>88</sup> Of the \$31.8 million in net revenue, \$12.7 million was from the 12 monthly auctions.<sup>89</sup> See Figure 3-6.

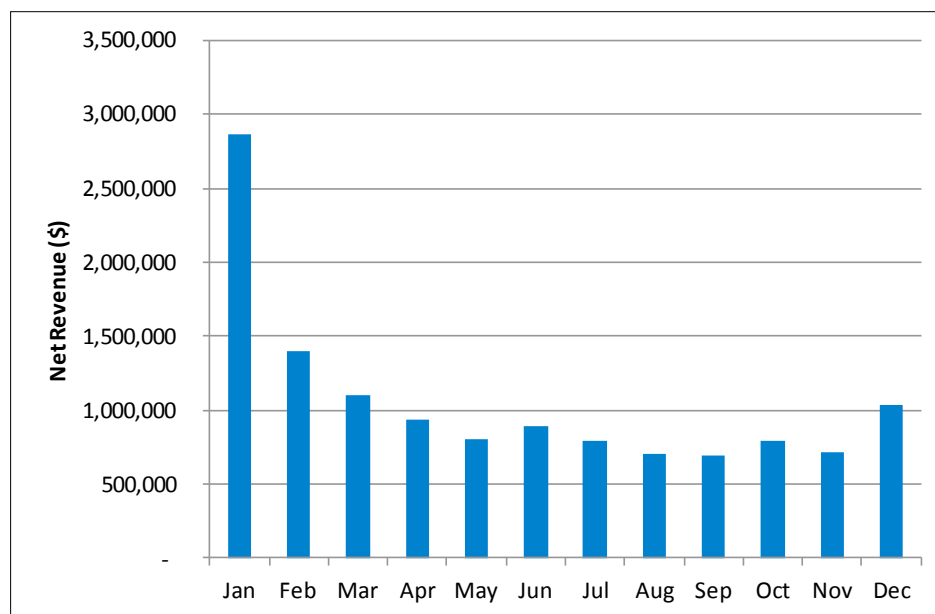


Figure 3-6: FTR monthly net revenues, 2014 (\$).

If FTR participants had perfect foresight, the total auction revenue would equal the day-ahead congestion revenue; however, market prices, the actual availability of generators, and the actual outages on the transmission system differ from the assumptions in the FTR auction, causing actual congestion to be different from what cleared in the auction.

In 2014, the day-ahead congestion revenue was \$34.2 million, a decrease from the \$46.2 million of day-ahead congestion revenue in 2013. Although the day-ahead congestion revenue decreased by 26% in 2014, the total auction revenue increased by 57%, from \$20.1 million in 2013 to \$31.6 million in 2014. In 2014, auction revenues were more representative of day-ahead congestion revenue than for prior years. Despite these shifts, congestion revenue was still adequate to fully fund FTR positions such that there was no shortage that needed to be allocated back to FTR holders. See Table 3-3.

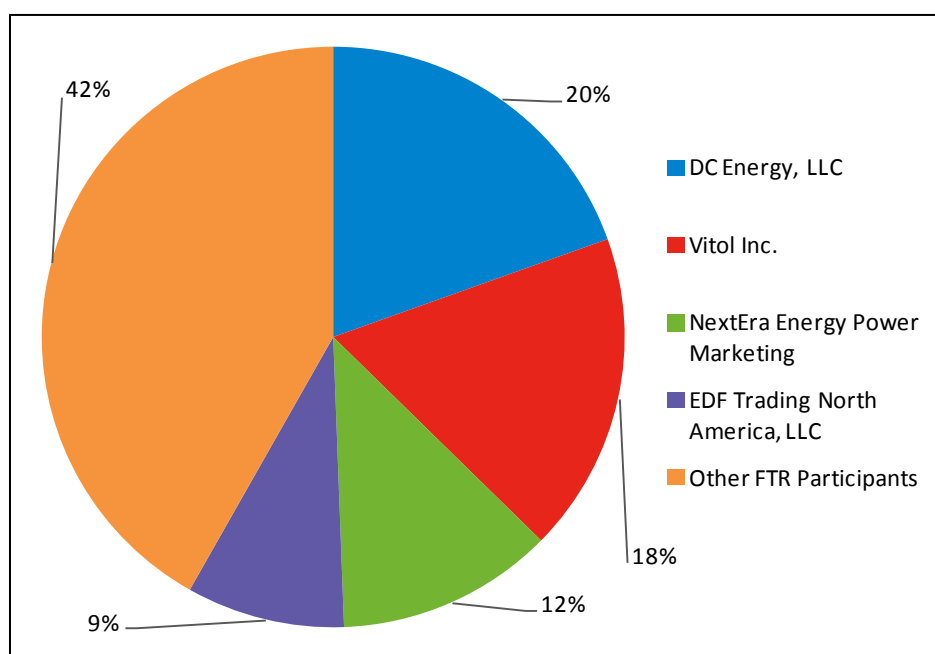
<sup>88</sup> Net revenue for the monthly auctions = (net revenue of bought FTRs) – (net revenue of sold FTRs).

<sup>89</sup> Beginning in 2013, the FTR annual auction was revised from a single-round auction to a two-round auction. See ISO New England Inc. and NEPOOL, *FTR Annual and Monthly Auction Changes*, Docket No. ER12-2195-000, FERC filing (July 3, 2012), [http://www.iso-ne.com/regulatory/ferc/filings/2012/jul/er12-2195-000\\_7-3-12\\_ftr\\_changes\\_part\\_1\\_of\\_2.pdf](http://www.iso-ne.com/regulatory/ferc/filings/2012/jul/er12-2195-000_7-3-12_ftr_changes_part_1_of_2.pdf).

**Table 3-3**  
**Comparison of Day-Ahead Congestion Revenue with Auction Revenue, 2012 to 2014**

	Total Auction Revenue (Millions \$)	Day-Ahead Congestion Revenue (Millions \$)	Auction Revenue as % of Day-Ahead Congestion Revenue
<b>2012</b>	16.1	29.3	55%
<b>2013</b>	20.1	46.2	43%
<b>2014</b>	31.6	34.2	92%

The most active FTR participants in 2014 were reviewed. Activity in this analysis is defined as the sum of all megawatts transacted by a participant, regardless of whether the FTRs were prevailing flow, counterflow, bought, or sold. The two most active participants with FTRs in 2014 were financial players who accounted for approximately 38% of total transacted megawatts. Financial participants are more likely to buy and sell FTR positions many times as new information becomes available. See Figure 3-7.



**Figure 3-7: Participant share of FTR activity, 2014.**

### 3.3 Forward Reserve Market

This section presents the outcomes of the two forward-reserve auctions conducted in 2014.

To maintain system reliability, all bulk power systems maintain operating reserve capacity to respond to contingencies, such as unexpected outages (refer to Sections 2.1.1.2 and 2.1.4). The locational FRM procures operating reserve capacity from participants with resources that can provide reserves, including 10-minute non-spinning reserve (TMNSR), 30-minute operating reserve (TMOR), and locational TMOR. Auctions are held twice a year, for a summer delivery

period and a winter delivery period. Participants submit offers to sell a quantity of an operating reserve type in a particular location and at a specific price. During the delivery period, a participant with an obligation must assign resources daily to meet the obligation or incur nonperformance penalties.

### 3.3.1 Auction Results

In 2014, FRM prices for the systemwide products increased in both the summer and the winter auctions. The 2014 summer systemwide TMNSR price increased 114% relative to summer 2013. Similarly, the 2014 winter systemwide TMNSR price increased by 6%.

The clearing price in the FRM auction in summer 2014 was \$12,709/MW-month. In the winter 2014/2015 auction, the clearing price was \$8,990/MW-month. See Table 3-4.

**Table 3-4**  
**Auction Clearing Price, Four Most Recent FRM Auctions (\$/MW-month)**

Location	Product	Summer 2013	Winter 2013/2014	Summer 2014	Winter 2014/2015
CT	TMOR	5,946	6,290	12,709	8,990
NEMA/Boston	TMOR	5,946	6,290	12,709	8,990
SWCT	TMOR	5,946	6,290	12,709	8,990
Systemwide	TMNSR	5,946	8,451	12,709	8,990
Systemwide	TMOR	5,946	6,290	12,709	8,990

The net payments to FRM resources equal the FRM auction clearing price minus the Forward Capacity Market (FCM) clearing price. The FCM clearing price for the 2014/2015 capacity commitment period (see Section 3.4) was \$3,209/MW-month; therefore, the net payment received by operating reserve providers was \$9,500/MW-month for the summer 2014 auction and \$5,781/MW-month for the winter 2014/2015 auction. Price separation across regions did not occur in the winter 2014/2015 FRM auction. The winter 2013/2014 auction had price separation with the TMNSR and TMOR products, which is attributable to increased systemwide operating reserve requirements.<sup>90</sup>

Several factors contributed to the auction clearing price increase observed in the summer 2014 auction. First, total TMNSR and TMOR requirements increased from 2,072 MW in the summer 2013 auction to 2,464 MW in the summer 2014 auction. The addition of replacement reserves contributed to an increase in the total reserve requirement. During summer 2014, the replacement reserve requirement was 160 MW. The increase in reserve requirement necessitated moving further up the supply curve to higher priced offers in order to clear the required quantity. Second, the FRM penalty structure changed after the winter 2013/2014 delivery period. Market participants who fail to meet their FRM obligation are now subject to higher penalties. Market participants may have quantified their expected exposure to these penalties and incorporated those risks into their offers. Third, the forward-reserve heat rate, used in the calculation of the daily forward-reserve threshold price, increased from 16,010

<sup>90</sup> The ISO proposed higher reserve requirements in 2012 to address risks identified in its Strategic Planning Initiative. This increase in reliability was acquired through the markets, including the local Forward Reserve Market. The increased requirement went into effect for the summer 2013 auction.

Btu/kWh in the summer 2013 auction to 18,310 Btu/kWh in the summer 2014 auction, and it increased from 15,962 Btu/kWh in the winter 2013/2014 auction, to 18,973 Btu/kWh in the winter 2014/2015 auction.<sup>91</sup> These increases imply a higher energy market threshold price at or above which designated resources must offer, and therefore higher opportunity costs of participating in the FRM.

Clearing prices decreased between the summer 2014 auction and the winter 2014/2015 auction. This was the result of a significant increase in supply and a modest decrease in demand between the auctions.

- The amount of supply offered into the auction to meet the TMNSR and TMOR requirements increased by almost 13%. Systemwide TMOR supply offered into the auction increased from 711 MW in the summer 2014 auction to 960 MW in the winter 2014/2015 auction, a 35% increase. Systemwide TMNSR supply offered into the auction increased from 2,509 MW in the summer 2014 auction to 2,669 MW in the winter 2014/2015 auction, a 6% increase.
- Both total TMNSR and TMOR requirements decreased from the summer 2014 auction to the winter 2014/2015 auction by about 3%. The TMNSR requirement went from 1,573 MW to 1,562 MW (a 1% decrease), while the TMOR requirement went from 891 MW to 831 MW (a 7% decrease).

### 3.3.2 Market Requirements

The ISO defines locational requirements, as well as a systemwide requirement, for each operating reserve product procured in the auction.<sup>92</sup> As noted above, in 2013 the ISO filed rules to increase the forward reserve requirements in alignment with other efforts to improve system recovery from contingencies. As a result, the systemwide requirements for TMNSR increased. The summer 2013 and winter 2013/2014 requirements were 1,349 MW and 1,532 MW, respectively. In summer 2014 and winter 2014/2015, these requirements increased to 1,573 MW and 1,562 MW, respectively. This represents a 17% increase in the summer requirements and a 2% increase in the winter requirements. See Table 3-5.

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<sup>91</sup> The heat rate used for a specific Forward Reserve Procurement Period is the implied heat rate value that occurs at the 97.5th percentile. Before the summer 2014 auction, the heat rate was calculated based on the historical period from the start of Standard Market Design (2013) to the most recent available data. Starting in the summer 2014 auction, the historical data were truncated to the last five-year period.

<sup>92</sup> The TMNSR and TMOR requirements are based on first- and second-contingency losses (refer to Sections 2.1.4 and 2.2.1). The methodology to calculate these requirements is described in OP 8 (Section 2.2.1) and *the ISO New England Manual for Forward Reserve* (Manual M-36) (December 3, 2013), [http://www.iso-ne.com/rules\\_proceeds/isone\\_mnls/index.html](http://www.iso-ne.com/rules_proceeds/isone_mnls/index.html).

**Table 3-5  
Local Operating Reserve Requirements  
Summer 2014 and Winter 2014/2015 Forward Reserve Auctions (MW)**

Location Name	Product	Summer 2013	Winter 2013/2014	Summer 2014	Winter 2014/2015
CT	TMOR <sup>(a)</sup>	747	578	900	363
NEMA/Boston	TMOR <sup>(a)</sup>	0	0	0	0
SWCT	TMOR <sup>(a)</sup>	0	155	94	87
Systemwide	TMNSR	1,349	1,532	1,573	1,562
Systemwide	TMOR <sup>(a)</sup>	723	915	891	831

(a) TMNSR also can be used to satisfy this requirement.

The additional systemwide requirement increased the amount of TMNSR that would be procured during the summer 2014 and winter 2014/2015 periods. The local operating reserve requirement for NEMA/Boston was zero because the external operating reserve support exceeded the local second contingency capacity requirement in this location in the auctions held in 2014.

### 3.3.3 External Reserve Support

Through external reserve support (ERS), resources within a local region as well as operating reserves available in other locations, if needed, can satisfy second contingency capacity requirements. As a result of transmission upgrades, the ERS to several import-constrained regions has changed. See Table 3-6.

**Table 3-6  
External Reserve Support in the Past Four FRM Auctions (MW)**

Location Name	Summer 2013	Winter 2013/2014	Summer 2014	Winter 2014/2015
CT	464	650	319	861
NEMA/Boston	1,224	2,109	959	1,723
SWCT	1,172	347	401	686

## 3.4 Forward Capacity Market

This section provides information on the 2014 outcomes of the Forward Capacity Auctions (FCAs), trends in capacity supply obligations, and FCM performance. An update is also provided on recent as well as proposed market rule enhancements.

The Forward Capacity Market is a long-term market designed to procure the resources needed to meet the region's local and systemwide resource adequacy requirements. The FCM is designed to procure and price capacity before the system will need it. This facilitates attracting new capacity resources (e.g., generation, imports, and demand resources), maintaining more efficient existing resources, and retiring less efficient resources through a coordinated market to meet the region's resource adequacy standard. The region developed the FCM in recognition

of the fact that the energy market does not provide sufficient revenue to facilitate new investment or, in many cases, cover the cost of maintaining and operating existing resources. If the capacity market does not replace this “missing” revenue, suppliers could not expect to recover their total costs and would not enter the marketplace—or would soon exit. In this event, additional demand would go unserved and reliable service would not be achieved. A central objective of the FCM is to create a revenue stream that replaces the “missing” revenue and thereby induce suppliers to undertake the investments necessary for reliable electric power service.

To allow enough time to construct new capacity resources, Forward Capacity Auctions are held each year, 40 months in advance of when the capacity resources must provide service. The period during which the resource is to provide service is called the capacity commitment period (CCP). Both new and existing capacity resources must qualify for an FCA to participate in the auction.

Each Forward Capacity Auction is conducted in two stages: a descending-clock auction followed by an auction-clearing process. The descending-clock auction consists of multiple rounds. During one of the rounds in each auction, the amount of capacity willing to remain in the auction at a given price level will equal or fall below the *Installed Capacity Requirement (ICR)*.<sup>93</sup> FCM resources that remain in the auction receive the FCA clearing price, as determined in the auction-clearing stage of the FCA.

Reconfiguration auctions take place before and during the capacity commitment period to allow participants with capacity supply obligations to trade their positions with other resources that do not have CSOs or wish to assume additional CSOs. Annual reconfiguration auctions (ARAs) to acquire one-year commitments are held approximately two years, one year, and just before the capacity commitment period begins. Monthly reconfiguration auctions, held beginning the first month of a capacity commitment period, adjust the annual commitments during the commitment period.

Two key provisions of the capacity payment structure currently are the peak energy rent (PER) adjustment and the penalties incurred for resource unavailability during shortage events (i.e., periods of scarcity).

#### 3.4.1.1 Peak Energy Rent

The *peak energy rent* adjustment is primarily a protection for load against energy prices in real-time that are above a threshold (i.e., *strike price*.), which is an estimate of the cost of the most expensive resource on the system. Load has paid in advance for sufficient capacity to maintain reliability through the FCM. The PER adjustment limits the gains to generators and import capacity resources, even those not producing energy, who sold capacity forward in the FCM in hours with high real-time prices resulting from shortage conditions.<sup>94</sup> This helps ensure that load does not pay through the FCM to maintain a fleet that meets reliability conditions and then later pay when those reliability conditions are not met and result in high real-time prices. The

<sup>93</sup> The ICR is the minimum amount of resources (level of capacity) a balancing authority area needs in a particular year to meet its resource adequacy planning criterion, according to *NPCC Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System*. This criterion states that the probability of disconnecting any firm load because of resource deficiencies shall be, on average, not more than 0.1 day per year.

<sup>94</sup> Demand resources are excluded from the PER adjustment.

PER value is based on revenues that would be earned in the energy market by a hypothetical peaking unit with heat rate of 22,000 British thermal units/kilowatt-hour (Btu/kWh) that uses the more expensive of either natural gas and No. 2 fuel oil.

The PER adjustment also discourages physical and more extreme economic withholding. The revenue adjustment resulting from the PER adjustment is based on the entire quantity sold in the capacity market, not just the portion of that capacity subject to the high real-time price. As a result, a withholding strategy that increases real-time price above the PER strike price can cause a significant revenue adjustment for the portfolio that outweighs the potential benefits of withholding.<sup>95</sup>

#### *3.4.1.2 Performance Incentives and Penalties*

The current FCM design includes penalties for resources that are unavailable during shortage events, in theory, creating an incentive for resources to be available during these events. Paying for actual performance during shortage events provides an incentive to resource owners to make investments to ensure that their resources will be ready and able to provide energy or operating reserves during these periods. To be effective, the capacity market must replicate the performance incentives that would exist in a fully functioning and uncapped energy market by linking payments to performance during scarcity conditions. Without this linkage, individual suppliers would lack the incentive to make investments that ensure the performance of their resources when needed most. Also, absent these incentives, resources that have not made such investments, and are presumably less reliable as a result, would become more likely to clear in future FCAs because they can offer at lower prices. This can create a structural bias in the FCM to clear less reliable resources, which will erode reliability over time.

Under the current FCM design, the consequences for nonperformance are negligible. Even with recent revisions to the shortage-event definition, as described in Section 3.4.3.3, shortage events are extremely rare. Furthermore, the current rules include numerous exemptions under which resources are considered “available” during a shortage event even when they do not provide any energy or operating reserves. Finally, even when a capacity resource is exposed to penalties under the current design, these penalties are capped such that FCM obligations can have no net loss.

The pay-for-performance design, described in more detail in Section 3.4.3.3, will replace the current FCM design starting in the 2018/2019 capacity commitment period with one that is a true, two-settlement forward market. Pay for performance is built around a well-defined product—the delivery of energy and operating reserves when they are needed most. Its rules apply in the same manner to all resource types, without exceptions. Pay-for-performance is expected to create strong incentives for resource performance, consistent with the goals of the capacity market.

### **3.4.2 Capacity Market Auction Outcomes**

This section reviews the outcomes and performance for the fourth through eighth FCAs and represents the auctions conducted through the reporting periods. Information on past capacity commitment periods is included in prior Annual Markets Reports.

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<sup>95</sup> The lower volatility of total payments might not affect the entire amount that load participants pay in the long run because the resources’ capacity bids reflect the lower PER-adjustment amounts.

### 3.4.2.1 Overview of Forward Capacity Market Results<sup>96</sup>

Table 3-7 shows the following data for FCA #4 through FCA #8:

- Total amount of capacity cleared in each auction
- Amount of capacity needed (i.e., the net ICR [NICR])
- Amount of surplus or deficit capacity
- Net capacity additions for that period
- Capacity price

**Table 3-7**  
**FCM Capacity Commitment Period Results, 2013/2014 to 2017/2018**  
**(MW and \$/kW-month)**

Factor	FCM Capacity Commitment Period <sup>(a)</sup>				
	2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017	2017/ 2018
<b>Cleared capacity resources (MW)</b>	37,500	36,918	36,309	36,220	33,702
<b>Net ICR (MW)</b>	32,127	33,200	33,456	32,968	33,855
<b>Surplus (Deficit) (MW)</b>	5,373	3,718	2,853	3,252	(153)
<b>Net capacity additions (MW)<sup>(b)</sup></b>	1,490	1,176	2,041	2,763	1,536
<b>Capacity price (\$/kW-month)</b>	2.95	3.21	3.13	3.15 <sup>(c)</sup>	7.03 <sup>(d)</sup>

(a) The FCM period began June 1, 2010; the capacity commitment period 2013/2014 is for the fourth FCA.

(b) Net capacity additions reflect cleared new capacity, excluding repowering projects and including imports.

(c) The NEMA/Boston capacity price was administratively set to \$14.999/kW-month for new resources. All other resources were paid \$3.15/kW-month.

(d) Insufficient competition was triggered in the auction; existing (non-NEMA/Boston) resources will be \$7.025/kW-month. The Capacity Carried Forward Rule was triggered in NEMA/Boston; new and existing resources in this zone will receive \$15/kW-month.

### 3.4.2.2 Reconfiguration and Bilateral Auction Results

The annual and monthly reconfiguration auctions provide participants the opportunity to exchange the CSOs they have for an annual commitment period or for a particular month. Each reconfiguration auction clears at a different price and quantity depending on the amount of CSO megawatts participants are willing to acquire and transfer. Table 3-8 shows that the clearing prices in the annual reconfiguration auctions increased steadily and were lower than the prices in the corresponding FCAs (shown in Table 3-7). The clearing price, while still less than the corresponding FCA, has been increasing to reflect the lower capacity margins expected for future capacity delivery periods.

<sup>96</sup> Sections 3.4.3.2 and 3.4.3.4 discusses the results of the eighth FCA in more detail.

**Table 3-8**  
**Annual Reconfiguration Auction Clearing Prices and Quantities,**  
**2014/2015 to 2016/2017 (MW and \$/kW-month)**

Commitment Period	Auction	Cleared CSOs (MW)	Clearing Price (\$/kW-month)
2014/2015	ARA #3	628	1.93
2015/2016	ARA #2	486	2.75
2016/2017	ARA #1	814	3.15 <sup>(a)</sup>

(a) In this reconfiguration auction, NEMA/Boston had a clearing price of \$12.11/kW-month.

Table 3-9 shows the clearing prices and quantities in the monthly reconfiguration auctions. Monthly auction clearing prices have increased thus far in the monthly auctions for the 2014/2015 commitment period compared with the 2013/2014 commitment period, the result of generation exiting during the capacity period.<sup>97</sup>

- For the 2013/2014 commitment period, the monthly prices ranged from \$0.25/kW-month to \$2.00/kW-month, and cleared volumes ranged from 169 MW (for June 2013) to 1,344 MW (for February 2014).
- The 2014/2015 commitment period, to date, has obtained prices ranging from \$0.25/kW-month to \$2.65/kW-month, whereas cleared volumes have ranged from 618 MW (for December 2014) to 912 MW (for November 2014).

**Table 3-9**  
**Clearing Prices and Quantities in the Monthly Reconfiguration Auctions,**  
**2013/2014 to 2014/2015 (MW and \$kW-month)**

Commitment Period	Average of Monthly Cleared CSOs (MW)	Weighted Average of Monthly Clearing Price (\$/kW-month)
2013/2014	778	0.87
2014/2015 (to date)	806	1.52

### 3.4.3 Trends in Capacity Supply Obligations

Table 3-10 presents data for generation, demand response, and import capacity cleared in the FCA for each capacity commitment period from 2013/2014 to 2017/2018.

<sup>97</sup> All the monthly reconfiguration auctions have not been completed for all months in the 2014/2015 capacity commitment period.

**Table 3-10**  
**FCA Cleared Capacity Resources for Each FCM Capacity Commitment Period,**  
**2013/2014 to 2017/2018 (MW)**

Factor	FCM Capacity Commitment Period				
	2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017	2017/ 2018
Installed generation <sup>(a)</sup>	32,247	31,439	30,757	31,641	29,425
Demand resources (capacity obligation)	3,261	3,468	3,628	2,748	3,041
External capacity contracts <sup>(a)</sup>	1,992	2,011	1,924	1,830	1,237
Surplus (deficit) above the ICR	5,373	3,718	2,853	3,252	(153)
<b>Total capacity resources</b>	<b>37,500</b>	<b>36,918</b>	<b>36,309</b>	<b>36,220</b>	<b>33,702</b>

(a) Data for FCM commitment periods are based on cleared megawatts, including those for energy efficiency and demand-response resources, which reflect the 600 MW cap for real-time emergency generation (RTEG); see Section 3.5.1.

Historically, more capacity cleared than the amount needed to meet the Installed Capacity Requirement. The committed capacity had risen to a high surplus of 5,373 MW for the 2013/2014 capacity commitment period. However, for the 2017/2018 capacity commitment period, the amount of committed capacity dropped to a deficit of 153 MW.

As shown in Table 3-11, resources have shed a portion of their CSO obtained in the FCA in advance of the commitment period. The changes in CSOs are due to various actions a participant or the ISO can take from the time of the FCA to the start of the commitment period. These actions include the following:

- Electing to prorate (i.e., reduce) a resource's CSO in the event excess capacity is obtained in the FCA<sup>98</sup>
- Submitting offers in the ARA due to changes in the ICR<sup>99</sup>
- Participating in the ARA and monthly reconfiguration auctions to increase or decrease the CSOs between resource types
- Receiving a flag for having a significant decrease in capacity, which may result in a reduction in a resource's CSO
- Terminating a resource in accordance with *Market Rule 1*, Section III.13.3.4 or III.13.1.4.6.2,<sup>100</sup>

Obligations can also be reduced or eliminated if capacity, previously held in the FCA for reliability, is released after the reliability constraint has been addressed.

<sup>98</sup> As described in *Market Rule 1*, Section III.13.2.7.3, resources can elect to prorate the FCA CSO if the capacity clearing price floor was reached in the FCA and capacity in excess of the ICR was procured.

<sup>99</sup> As described in *Market Rule 1*, Section III.13.4.3, the ISO may submit supply offers and demand bids in ARAs to address year-to-year changes in the ICR.

<sup>100</sup> *Market Rule 1*, Section III.13.3.4, is "Covering Capacity Supply Obligation where Resource Will Not Achieve Commercial Operation by the Start of the Capacity Commitment Period." Section III.13.4.2.1.3 is "Significant Decrease in Capacity."

**Table 3-11**  
**FCA Qualified Capacity and Obligations, FCA #4 to FCA #8 (MW)**

<b>FCM Capacity Commitment Period</b>	<b>Resource Type</b>	<b>FCA Qualified Capacity</b>	<b>FCA Obligation<sup>(a)</sup></b>	<b>June Obligation</b>
<b>2013/2014</b>	Demand resource	4,147	3,349	1,665
	Generation	33,665	32,247	29,702
	Import	2,600	1,992	1,258
<b>2014/2015</b>	Demand resource	4,146	3,590	1,888
	Generation	32,863	31,439	29,704
	Import	2,352	2,011	1,167
<b>2015/2016</b>	Demand resource	4,257	3,645	2,483
	Generation	32,209	30,757	29,644
	Import	2,135	1,924	1,337
<b>2016/2017</b>	Demand resource	3,674	2,748	2,465
	Generation	32,463	31,641	29,347
	Import	2,435	1,830	1,616
<b>2017/2018</b>	Demand resource	3,277	3,041	2,856
	Generation	29,790	29,425	29,418
	Import	1,826	1,237	1,237

(a) This represents the FCA obligation before a resource's proration election and does not account for the 600 MW RTEG cap.

Table 3-11 shows the change from FCA qualified capacity, from obtaining the initial obligation, to the result in the delivery month at the beginning of the commitment period. The June obligations shown in the table reflect the CSOs as of February 23, 2015, and the levels of activity that have occurred for that obligation month. Not all annual and monthly reconfiguration auctions have occurred for the 2015/2016, 2016/2017, and 2017/2018 commitment periods. For example, no reconfiguration auctions have occurred for the 2017/2018 commitment, while ARA #1 and a bilateral period have occurred for the 2015/2016 commitment period.

#### 3.4.3.1 Peak Energy Rent Trends

On December 1, 2010, the fuel used to calculate the PER adjustment was changed from the lower price of natural gas and No. 2 fuel oil to the higher price of the two.<sup>101</sup> As a result, the strike price increased from approximately \$116/MWh on November 30, 2010, to \$425/MWh on December 1, 2010. Because the amount of the PER adjustment is calculated from a moving 12-month average, the gas-based strike price and adjustment affected the PER adjustment through November 2011.

PER adjustments decreased through 2011 because of an increase in the strike price. From the effective date (December 2010) of the February 17, 2011, FERC order through the end of 2012

<sup>101</sup> FERC, *Order Accepting Tariff Provisions in Part, and Rejecting Tariff Provisions in Part*, Docket No. ER11-2427-000, (February 17, 2011), [http://www.iso-ne.com/regulatory/ferc/orders/2011/feb/er11-2427-000\\_2-17-11\\_partial\\_accept-reject\\_tariff\\_rev.pdf](http://www.iso-ne.com/regulatory/ferc/orders/2011/feb/er11-2427-000_2-17-11_partial_accept-reject_tariff_rev.pdf). At the beginning of the FCM transition period (December 2006), and during most of the transition period, the prices of natural gas and oil were close to each other. Thus, the difference between adopting one or the other fuel as the standard was not substantial. This changed, however, when gas and oil prices diverged in January 2009.

(and in particular, for all of 2012), no hours had a positive hourly PER.<sup>102</sup> As a result, the PER adjustment fell to zero in December 2011 when all effects from a gas-based calculated strike price ended.<sup>103</sup> PER adjustments have increased from mid-2013 to the present as a result of elevated fuel costs and load levels leading to higher real-time prices, especially during cold and hot weather periods. When real-time energy prices exceed the PER threshold, the PER adjustment is triggered. See Table 3-12.

**Table 3-12**  
**Monthly PER Adjustments, 2011 to 2014 (\$ Millions)**

Month	2011	2012	2013	2014
January	17.6	-	-	3.2
February	17.2	-	0.4	2.9
March	16.8	-	0.4	2.8
April	16.3	-	0.4	2.8
May	16.3	-	0.4	2.8
June	14.0	-	0.4	2.9
July	12.1	-	0.5	2.8
August	7.9	-	1.9	1.3
September	2.9	-	1.9	1.3
October	0.3	-	2.0	1.3
November	0.2	-	2.0	1.3
December	-	-	2.3	1.1
<b>Total</b>	<b>121.7</b>	<b>-</b>	<b>12.6</b>	<b>26.6</b>
<b>Total 2011 to 2014</b>				<b>160.9</b>

On March 6, 2015, the ISO and the New England Power Pool (NEPOOL) filed market rule changes to eliminate PER on a prospective basis starting with the capacity commitment period that begins on June 1, 2019.<sup>104</sup> The mechanism is no longer needed to serve its intended purposes, and retaining the mechanism could result in higher capacity market costs without producing any substantial benefits. Changes to the New England region's electricity market since the mechanism was first put in place has reduced concerns about the exercise of market power:

- First, a number of rule changes have improved real-time price formation, resulting in a high percentage of expected real-time load clearing in the day-ahead market. This

<sup>102</sup> *Id.*

<sup>103</sup> 2011 Annual Markets Report, Section 3.5.3.2, [http://www.iso-ne.com/static-assets/documents/markets/mkt\\_anlys\\_rpts/annl\\_mkt\\_rpts/2011/2011\\_amr\\_final\\_051512.pdf](http://www.iso-ne.com/static-assets/documents/markets/mkt_anlys_rpts/annl_mkt_rpts/2011/2011_amr_final_051512.pdf).

<sup>104</sup> ISO New England Inc. and New England Power Pool, Docket No. ER15-000, PER Mechanism Changes, FERC Filing (March 6, 2015), [http://www.iso-ne.com/static-assets/documents/2015/03/er15-1184-000\\_3\\_6\\_15\\_fcm\\_per.pdf](http://www.iso-ne.com/static-assets/documents/2015/03/er15-1184-000_3_6_15_fcm_per.pdf). The region's private and municipal utilities formed NEPOOL to foster cooperation and coordination among the utilities in the six-state region and ensure a dependable supply of electricity. Today, NEPOOL members serve as ISO stakeholders and market participants; the NEPOOL stakeholder process provides advisory input on market, reliability, and Open Access Transmission Tariff (OATT) matters. More information is available at [http://www.iso-ne.com/committees/nepool\\_part/index.html](http://www.iso-ne.com/committees/nepool_part/index.html).

means that most suppliers who have taken on a day-ahead obligation have a strong disincentive to seek increased prices in real time.

- Second, the pay-for-performance changes that will become effective in 2018 (see Section 3.4.3.3) replicate the intended incentives of the PER mechanism. The potential additional protection provided by peak energy rent while PFP is in place has been evaluated. PFP provides adequate disincentives to exercise market power through physical withholding given the portfolio composition requirements and information barriers to successfully execute physical withholding. Also, the IMM has a range of tools to detect and address physical withholding.
- Third, improved, automated Real-Time Energy Market mitigation measures have been put in place.

These rule changes, combined with the IMM and FERC's authority to investigate and sanction economic withholding, should sufficiently remove any incentive for capacity suppliers to seek to exercise market power. Given this, the IMM did not oppose the proposal eliminating the PER.

#### 3.4.3.2 Detailed Results of the Eighth Forward Capacity Auction

This section presents the FCA #8 results in detail and a review of the results. On February 3, 2014, ISO-NE conducted the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period (FCA #8).

The auction began at the starting price of \$15.82/kW-month and stopped with the withdrawal of capacity at a price of \$14.99/kW-month. At that point, all system and zonal capacity requirements were satisfied and the FCA #8 clearing price was set by an auction clearing function at \$15.00/kW-month. While the auction clearing price was \$15.00/kW-month, the Insufficient Competition rule resulted in two-tiered pricing throughout the system where new resources would receive the auction clearing price of \$15.00/kW-month and existing resources would receive the administrative price of \$7.025/kW-month.<sup>105</sup>

However, the Carry Forward rule applied in NEMA/Boston due to excess procurement in the prior auction. The Carry Forward rule effectively raised the price paid to existing resources in NEMA/Boston to \$15.00/kW-month. The final pricing for FCA #8, after application of the various pricing rules, is shown in Table 3-13 below.

**Table 3-13**  
**FCA #8 Prices**

	<b>New Resources (\$/kW-month)</b>	<b>Existing Resources (\$/kW-month)</b>
<b>NEMA/Boston</b>	\$15.00	\$15.00
<b>Maine, Connecticut and Rest-of-Pool</b>	\$15.00	\$7.03

In most of the prior auctions, new and existing resources were paid the same clearing price. FCA #8 was different. In FCA #8, there were not enough new resources competing to satisfy the

<sup>105</sup> The \$7.025/kW-month administrative price was pre-determined by the ISO and approved by the FERC in a January 24, 2014 Order.

region's capacity requirement. This condition is called "Insufficient Competition" and occurs when there is not enough existing capacity to meet the entire capacity requirement and not enough competition among new capacity to meet the remaining or residual capacity requirement.<sup>106</sup> Under this condition, the Insufficient Competition pricing rule is applied which is a market power mitigation feature of pricing in the capacity market. It is designed to balance the interests of buyers paying for capacity by building in price protection under conditions of scarcity and the interests of developers by paying a price that reflects the need to attract new resources and retain existing capacity.

Applying the insufficient competition rule would have resulted in all new resources in the region being paid the FCA #8 clearing price of \$15/kW-month and all existing resources in the region being paid an administratively set price of \$7.025/kW-month.

Conditions in the NEMA/Boston zone created an exception to the Insufficient Competition rule. In FCA #7, a large new resource cleared (the 674 MW Footprint Power facility) resulting in approximately 500 MW of excess supply in the NEMA/Boston zone. The excess supply in the NEMA/Boston zone from FCA #7 triggered the "carry forward rule" for pricing in the NEMA/Boston zone for FCA #8.<sup>107</sup> The intent of the carry forward rule is to reset the clearing price administratively when new additional capacity would have been needed (and would have set the clearing price), but could not because of excess new capacity procured in the prior auction. The carry forward rule applies the same price to new and existing resources in the zone. In addition, the NEMA/Boston area was an import constrained zone for FCA #8 and resources within an import constrained area cannot be paid less than the price set for resources in the rest of pool.<sup>108</sup> Therefore, new and existing resources in the NEMA/Boston zone were paid the same \$15.00/kW-month capacity clearing price as new resources in the other zones.

The ISO's filing of the results of FCA #8 became effective on September 18, 2014. In its order on FCA #8 results, FERC noted that the tariff may be insufficient to ensure just and reasonable rates, given the changing balance of supply and demand in New England. FERC explained that although it had previously determined that most imports should be treated like existing internal resources for mitigation purposes, the tariff did not at the time require that the importers' delist bids be consistent with their net risk-adjusted going-forward costs and opportunity costs, as it does with respect to the delist bids for other existing resources. FERC concluded that this circumstance may create an opportunity for importers to exercise market power, and it may otherwise result in preferential or unduly discriminatory treatment favoring importers over other capacity resources. As a result, FERC required the ISO to either revise its tariff to provide for a review of import offers before each FCA or to show why it should not be required to do so. The ISO submitted a compliance filing to the show-cause order on October 16, 2014, in which it proposed more comprehensive mitigation rules for imports, and FERC conditionally accepted the tariff revisions on December 15, 2014.<sup>109</sup>

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<sup>106</sup> *Market Rule 1*, III.13.2.8.2.

<sup>107</sup> *Market Rule 1*, III.13.2.7.9.

<sup>108</sup> The import-constrained zone rule ensures that prices in import-constrained zones where capacity is, by definition, less abundant reflect that relative scarcity when compared to prices in zones that are not import-constrained where capacity is more abundant. See *Market Rule 1*, III. 13.2.7.1.

<sup>109</sup> FERC, *Order Conditionally Accepting Tariff Revisions and Directing Compliance Filings*, (December 15, 2014), [http://www.iso-ne.com/static-assets/documents/2014/12/er15-117-000\\_el14-99-000\\_12-15-14\\_order\\_accept\\_show\\_cause\\_compliance.pdf](http://www.iso-ne.com/static-assets/documents/2014/12/er15-117-000_el14-99-000_12-15-14_order_accept_show_cause_compliance.pdf).

*Maximum Capacity limits (MCLs) and Local-Sourcing Requirements (LSRs) for FCA #8.* Table 3-14 shows the system and local capacity requirements for FCA #8. Approximately 33,800 MW of capacity were needed to ensure systemwide resource adequacy. At the local level, capacity purchases from the Maine zone were limited to 3,960 MW because of an export constraint. The Connecticut and NEMA/Boston zones are import-constrained zones. A local-sourcing requirement for the CT zone of approximately 7,300 MW and an LSR for NEMA/Boston of approximately 3,400 MW were included for each region in the auction.

**Table 3-14**  
**Capacity Requirements or Limits for FCA #8 (MW)**

Auction	Net Installed Capacity Requirement	Maximum Capacity Limit	Local-Sourcing Requirement	
	Systemwide	Maine	CT	NEMA/Boston
<b>FCA #8</b>	33,855	3,960	7,319	3,428

*Resource Qualification.* Table 3-15 summarizes the existing and new qualified capacity for FCA #8 by zone and compares this capacity to the relevant capacity requirement (i.e., NICR, MCL, and LSR). Systemwide, existing capacity (34,983 MW) was approximately 1,100 MW greater than the NICR of 33,855 MW. For the local zones, existing capacity slightly exceeded the MCL for Maine; new capacity in Maine added to this excess. In the import-constrained areas, Connecticut was able to satisfy its local capacity requirement with existing capacity, and proposed new capacity for Connecticut added a small amount to the area totals. NEMA/Boston lacked sufficient existing capacity to satisfy the local capacity requirement; therefore, this zone required new capacity to meet its LSR.

**Table 3-15**  
**Qualified Capacity Compared with Requirement or Limit, FCA #8 (MW)**

Zone	Existing	New	Total	Capacity Requirement or Limit
<b>Connecticut</b>	9,275	7	9,282	7,319
<b>Maine</b>	3,536	272	3,808	3,960
<b>NEMA/Boston</b>	3,695	183	3,878	3,428
<b>Rest-of-Pool</b>	16,226	1,699	17,925	19,148
<b>Total</b>	<b>32,732</b>	<b>2,161</b>	<b>34,893</b>	<b>33,855</b>

Table 3-16 shows the breakdown of qualified capacity by resource type for each zone. Proposed new additions to capacity were small compared with import resources in the Rest-of-Pool zone and generator resources in NEMA/Boston. Consistent with the ISO tariff rules, import capacity qualifies as new capacity in each auction. Therefore, import capacity receives an annual, rather than long-term, obligation to supply capacity to the New England market if it clears. For FCA #8, almost all the “new” capacity within the Maine zone was import capacity.

**Table 3-16**  
**Qualified Capacity by Resource Type and Qualification Status, FCA #8 (MW)**

Zone	Existing			Existing Total	New			New Total	Total
	Demand	Generator	Import		Demand	Generator	Import		
Connecticut	833	8,441	-	9,275	7	-	-	7	9,282
Maine	387	3,149	-	3,536	32	6	234	272	3,808
NEMA/Boston	468	3,227	-	3,695	170	14	-	183	3,878
Rest-of-Pool	1,194	14,943	89	16,226	185	11	1,503	1,699	17,925
<b>Total</b>	<b>2,882</b>	<b>29,760</b>	<b>89</b>	<b>32,732</b>	<b>394</b>	<b>30</b>	<b>1,737</b>	<b>2,161</b>	<b>34,893</b>

Fifty delist bids from existing capacity resources were entered in the auction for FCA #8. The ISO retained all these bids for a total of 425 MW, provided by both demand resources (160 MW) and generation resources (265 MW). All the delist bids were for a single year, allowing these resources to retain the option of re-entering the capacity market during FCA #8. See Table 3-17.

**Table 3-17**  
**Delisted Capacity by Zone and Resource Type, FCA #8 (MW)**

Zone	Demand	Generator	Total
Connecticut	81	-	81
Maine	4	1	5
NEMA/Boston	15	21	36
Rest-of-Pool	60	243	303
<b>Total</b>	<b>160</b>	<b>265</b>	<b>425</b>

#### 3.4.3.3 FCM Performance Incentives

As discussed in the *2012 and 2013 Annual Markets Report*, design features of the FCM, built to ensure that resources perform when system reliability is at risk, have not been effective. Through the end of 2014, only one shortage event has occurred, and peak energy rent deductions remain low compared with total FCM payments.

The ISO has undertaken several actions to strengthen the FCM incentive structure:

- Definition of the FCM Shortage-Event Trigger:** A shortage event can be triggered when the Reserve Constraint Penalty factor for 30-minute operating reserves is activated for 30 or more contiguous minutes and Action 2 under OP 4 is implemented for the same 30 contiguous minutes. Under the prior rule, a shortage-event was triggered only when an RCPF was activated for 10-minute non-spinning reserves for 30 or more contiguous minutes. This change was implemented in November 2013.
- FCM Pay-for-Performance Market Design:** The pay-for-performance design is based on the two-settlement logic generally used in forward markets, which entails two key elements. The first element is a forward position in which a quantity of capacity is obligated, or sold, in the capacity auction. Each megawatt is paid at the auction clearing price, and the sale creates a resource-specific physical obligation and forward financial position in the capacity market. A resource's forward financial position is a share of the system's energy and reserve requirements during operating reserve deficiencies. The

second element includes a settlement for deviations. A resource that delivers more than its share of the system's requirements during an operating reserve deficiency (i.e., an overperformer) will be paid for that incremental production. If it delivers less than its share (i.e., it underperforms), it will "buy out" of its position by paying other resources that did deliver. Positive and negative deviations are paid or charged at the same rate specified in the tariff.

The two-settlement approach is standard in forward contracts, both for electricity and commodities, ranging from oil to pork bellies to iron ore. In fact, the two-settlement design underlies the design of New England's day-ahead and real-time electricity markets and is well understood by stakeholders.

Under PFP, buyers will pay the auction clearing price to all resources that clear in the auction. Because the overperformers will be paid by the underperformers, buyers will not bear the short-run risk of covering any unexpectedly high performance payments. This will continue to provide buyers with a predictable capacity price three years out, after the close of each Forward Capacity Auction. Having underperformers pay overperformers will also provide strong incentives for each resource to perform as needed and for overperformers to benefit by helping meet the system's needs. These incentives will place performance risk on all FCM resources, and each resource will be allowed to price this risk in its future capacity auction bids.

Pay-for-performance will become fully effective on June 1, 2018. With respect to the implementation of pay-for-performance, the ISO made a compliance filing on July 14, 2014, in response to a FERC order requiring the ISO to increase Reserve Constraint Penalty Factors for 30-minute operating reserves, from \$500/MWh to \$1,000/MWh, and 10-minute non-spinning reserves, from \$850/MWh to \$1,500/MWh.<sup>110</sup> This change was implemented on December 3, 2014. Other portions of the rule pertaining to certain changes to the tariff's defined terms and FCM rules that must apply during the qualification process for FCA #9 became effective on June 9, 2014.<sup>111</sup>

#### 3.4.3.4 Additional Analysis and Review of Capacity Market Mitigation Rules

The results of the FCA #8 auction and the show-cause order triggered additional analysis and review of the capacity market mitigation rules. Recent and future rule changes that have been or are currently going through the stakeholder process include the following:

**Import cost reviews (FCA #9).** In the October 16, 2014, filing, the ISO submitted rule revisions to provide for the review and potential mitigation of importers' supply offers before each annual Forward Capacity Auction.<sup>112</sup> The rule revisions determine which import suppliers have market power (that is, which are "pivotal") and to mitigate these suppliers in a manner consistent with the mitigation applied to existing resources.

<sup>110</sup> *ISO New England Inc. and New England Power Pool, Docket No. EL14-52-000; Compliance Filing of Two-Settlement Forward Capacity Market Design*, parts 1 and 2 of 2 (July 14, 2014) [http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14\\_2419\\_000\\_pfp\\_comp\\_7\\_14\\_2014.pdf](http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14_2419_000_pfp_comp_7_14_2014.pdf) and [http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14\\_2419\\_001\\_pfp\\_comp\\_7\\_14\\_2014.pdf](http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/jul/er14_2419_001_pfp_comp_7_14_2014.pdf).

<sup>111</sup> FERC, *Order on Compliance Filing* (October 2, 2014), [http://www.iso-ne.com/static-assets/documents/2014/10/er14-2419-000\\_-001\\_10-2-14\\_pay\\_for\\_performance\\_compliance\\_order.pdf](http://www.iso-ne.com/static-assets/documents/2014/10/er14-2419-000_-001_10-2-14_pay_for_performance_compliance_order.pdf)

<sup>112</sup> *ISO New England Inc., Response to Order to Show Cause*, (October 16, 2014), [http://www.iso-ne.com/static-assets/documents/2014/10/er15-117-000\\_show\\_cause\\_10-16-2014.pdf](http://www.iso-ne.com/static-assets/documents/2014/10/er15-117-000_show_cause_10-16-2014.pdf).

Most imports are qualified as new capacity for treatment in the auction. Grandfathered imports (or imports associated with a long-term contract that cleared as new capacity in a prior FCA and are still under contract) are qualified as existing capacity. Because most imports have single-year contracts, most imports are qualified as new capacity each year. This differs from how generation and demand resources are qualified as *new* or *existing*. For these resources, all capacity is *new* until it has cleared in a prior FCA, after which it is always treated as *existing*.

Existing import capacity resources may not exit the FCA above the dynamic delist threshold, unless the IMM has reviewed and approved the participant's submitted delist bid. If the lead market participant of an existing capacity resource is determined to be pivotal, the existing import capacity resources may not exit the FCA at prices above the approved delist bid but rather only at the approved delist bid price. Existing import capacity resources that do not submit a delist bid may exit the auction at prices below the dynamic delist bid threshold without any review.

Under the proposed rule changes, the vast majority of new import capacity resources are treated similar to "existing resources" for determining whether market power mitigation will be needed. These imports will be subject to supplier-side mitigation in the same way that existing resources are currently evaluated, and these imports will be exempt from buyer-side mitigation.

**Comprehensive pivotal supplier test (FCA #10).** The pivotal supplier test that currently applies only to import portfolios will be combined with the test that applies to suppliers generally. The comprehensive pivotal supplier test will do the following:

- Consider both existing internal resources and import resources when assessing the competitiveness of supply
- Account for system constraints (e.g., capacity transfer limits)
- Be conducted closer to the start of the Forward Capacity Auction

Changes associated with the auction process are also being proposed to complement the proposed pivotal supplier test.

**Zonal sloped demand curves (FCA #10).** In its May 30, 2014 order, FERC accepted the systemwide sloped demand curve for the FCM.<sup>113</sup> The sloped demand curve at the system level was in effect for FCA #9.

Along with ISO management we have identified issues regarding the potential for market power to be exercised that can have an inappropriate impact on prices and scarcity pricing within capacity zones with zonal demand curves, specifically within import-constrained capacity zones.<sup>114</sup>

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<sup>113</sup> FERC, *ISO New England Inc. and New England Power Pool Participants Committee, Order Accepting Tariff Revisions*, 147 FERC ¶ 61,173 (May 30, 2014) (the May 30, 2014, order).

<sup>114</sup> Currently, four capacity zones exist for FCA #9. Three are localized and are import constrained, and the fourth is the Rest of Pool zone that represents the balance of the system requirements beyond those reflected in the three import-constrained zones.

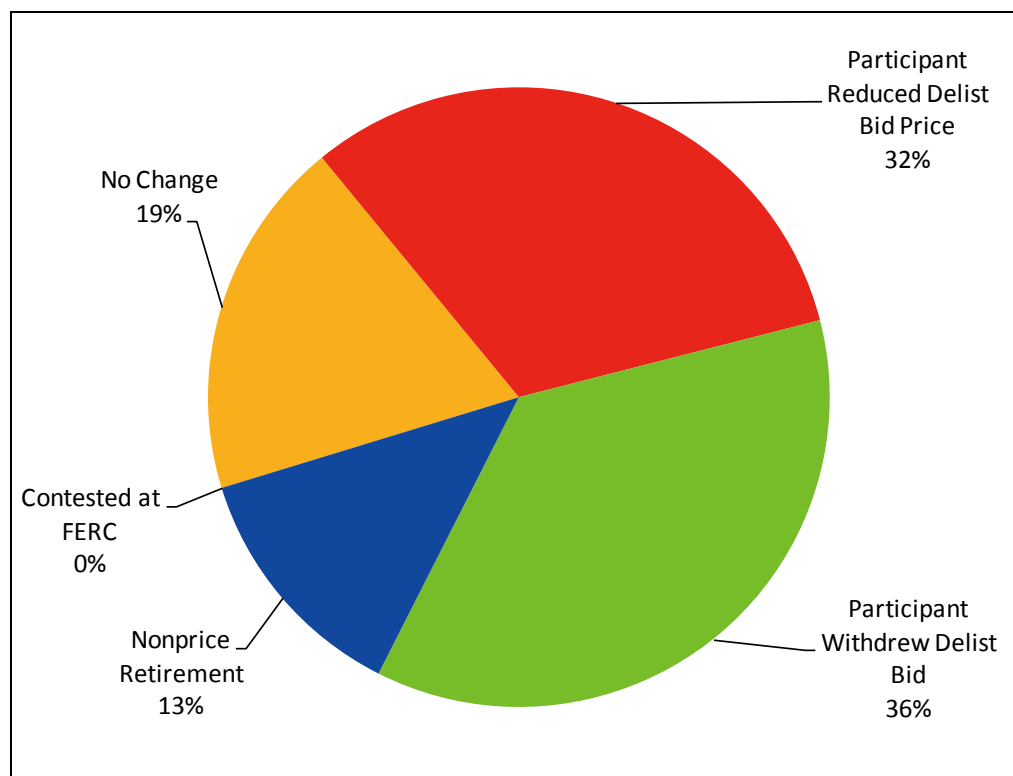
Compared with the system as a whole, import-constrained capacity zones inherently are relatively small and have a higher risk of being structurally uncompetitive. Adding price responsiveness through a sloped demand curve can dampen the financial impact of the exercise of market power. The extent to which zonal curves themselves can address market power depends on several factors, including the degree of price responsiveness (the slope of the demand curve), the concentration of ownership of existing resources within the zone, and the ability of new entry from suppliers without market power to contest the market share of existing capacity.

In zones that do not have adequate supply or sufficient competition, which could be brought on by several factors, the appropriateness of relying solely on the sloped demand curve to address noncompetitive conditions is currently being discussed and evaluated with stakeholders. Two administrative pricing rules are in place in the tariff that prevent the potential for market power and artificially high prices when competition is insufficient (see above) or the supply is inadequate.

**Accuracy of static delist bids (FCA #10).** Flexibility in submitting, modifying, and withdrawing static delist bids was originally created so that the price of one of these bids could be fine-tuned (downward only) should the factors making up the price vary between the submittal of the delist bid and the Qualification Determination Notification (QDN). Under the current rules, a participant may submit a static delist bid and, after a review during the finalization window, can do any one of the following:

- Withdraw the static delist bid, whether or not the bid was mitigated
- Lower the static delist bid price from either the accepted price or, if mitigated, from the mitigated price
- Convert a delist bid into a nonprice retirement request

While this flexibility originally was anticipated to create some upward pressure on submitted prices, the actual degree of price reductions observed during the finalization windows to date has been significant (approximately 32% on average for FCA #8 and #9). See Figure 3-8.



**Figure 3-8: Changes in static delist bids from a review of FCA #8 and FCA #9.**

Figure 3-8 also shows the percentage of submitted static delist bids completely withdrawn (approximately 36% of those submitted for FCA #8 and #9), whether or not the submitted price was mitigated. Without a static delist bid, the resource is a price-taker in the auction, unless the auction price falls below the \$3.94/kW-month, below which stage it can choose to dynamically delist.

On May 1, 2015, the IMM filed market rule changes that address the potential exercise of market power in the Forward Capacity Market. The first two parts of the market rule changes address the treatment of de-list bids. First, the IMM proposed to increase the Dynamic De-List Bid Threshold from \$3.94 to \$5.50/kW-month. This change was intended to avoid having the IMM review de-list bid information at prices that already are low enough to ensure that there will be adequate competition in the market, so that the exercise of market power is not a concern.

Second, the IMM proposed to limit the amount of flexibility that is currently afforded to capacity suppliers to modify Static De-List Bids after those bids have been submitted and reviewed by the IMM and also to eliminate the option to replace a Static De-List Bid with a Non-Price Retirement Request in certain instances. These changes are intended to encourage the submission of Static De-List Bids that are closer to actual cost and remove any incentive for capacity suppliers to use the Static De-List Bid process to explore whether the IMM will allow bid prices that substantially exceed costs. Together, these two changes are motivated by the desire to maintain the continued integrity of the market power mitigation structure in the capacity market and to allow both the IMM and capacity suppliers to focus more closely on those bids that actually raise significant market power concerns.

The third part of the proposed changes involves improvements to the pivotal supplier test that the IMM administers prior to the auction to determine if a capacity supplier has the potential to exercise market power. The proposed market rule establishes a single pivotal supplier test that applies to both capacity imports and existing resources. The improvements include a consistent treatment of interface constraints for purposes of determining whether a supplier is pivotal, moving the performance of the test closer to the time of the auction and a new definition of “control” that will more accurately account for which resources should be included in the assessment of a supplier’s overall capacity portfolio.

The fourth and final part of the proposed changes involves improvements to the rules governing the treatment of import capacity resources in the Forward Capacity Auction. The proposed changes will ensure that capacity imports that are more akin to existing resources receive the same mitigation treatment in the Forward Capacity Auction as existing resources. The changes also will ensure that capacity imports that are more akin to new resources receive the same treatment as other new resources during the conduct of the auction.

**Dynamic delist change (FCA #10).** In the FCM, two types of delist bids enable a resource to leave the capacity market for a single capacity commitment period. Resources that wish to leave the market at prices equal to or above the dynamic delist bid threshold must submit static delist bids in advance of the FCA for review. If resources wish to leave the market at prices below the dynamic delist bid threshold price, they may submit a dynamic delist bid during the FCA without review.

The dynamic delist bid threshold used for FCA #9 did not explicitly account for a risk premium, yet all the submitted static delist bids for FCA #9 included a risk premium. The IMM recommends raising the dynamic delist threshold from \$3.94/kW-month (FCA #9 price) to \$5.50/kW-month (FCA #10 price), which represents a competitive offer from a fossil steam unit, the type of existing capacity resource most likely to seek to leave the auction and therefore could be the marginal unit if more existing capacity exists than needed to meet the ICR. In addition, the IMM will recalculate the dynamic delist bid threshold no less than once every three years. When the dynamic delist bid threshold is recalculated, the results of the recalculation with stakeholders will be reviewed, and the new dynamic delist bid threshold will be filed with FERC before the existing capacity qualification deadline for the associated FCA.

**Uneconomic nonprice retirements (NPRs) (FCA #11).** The owners of existing generators can potentially exercise market power in an import-constrained zone through the uneconomic retirement of an existing resource.<sup>115</sup> When existing and new supply are not abundant in a capacity zone, an incumbent supplier can seek to retire an existing resource to reduce available supply. This action will have a price-increasing effect within that capacity zone, which will benefit the remainder of the supplier’s portfolio in that capacity zone. In cases where capacity zones are sufficiently small, the retirement of even a single resource of moderate size can have a significant price impact even with sloped zonal demand curves.

Market rule changes are being recommended that will provide a process for reviewing options for capacity market participation or retirement, and market power mitigation measures in the capacity auction. The proposed process, with these components, eliminates the potential that a capacity auction will be executed with known market power resident through early resource

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<sup>115</sup> Uneconomic retirement is the premature withdrawal of a generation resource’s capacity from the capacity market if expectations over its remaining life indicate that continued operation of the resource would be economically viable.

retirement. It will also provide a means for resources to retire through the market, as opposed to administratively as is now the case, and potentially be replaced by new generation in that same capacity auction. The External Market Monitor has also recommended that the ISO adopt a measure that addresses the potential for retirement delist bids to be used to increase FCA prices above competitive levels.<sup>116</sup>

### 3.5 Demand Response

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The following section reviews the participation and outcomes of demand resources in New England for 2014.

#### 3.5.1 Background and Review

Demand resources have been part of New England's wholesale electricity market since the start of the markets in 2003 when the ISO implemented a series of demand-response programs. Over the years, the programs were enhanced to include three basic categories: demand response that reduced load to support system reliability, demand response that reduced load in response to wholesale energy prices, and demand resources that reduced load through energy efficiency and other nondispatchable measures.

In 2010, demand resources were integrated into the FCM where they offer in the Forward Capacity Auctions, take on capacity supply obligations, and receive capacity payments comparable to other supply-side resources. The two broad categories of demand resources in the FCM are active and passive demand resources. *Active demand resources* are dispatchable and reduce load in response to ISO dispatch instructions. *Passive demand resources* are not dispatchable and provide load reductions during predetermined periods.

In addition to *real-time demand response* (RTDR) resources, which reduce load within 30 minutes of receiving an ISO dispatch instruction, active demand resources include *real-time emergency generation* (RTEG) resources, which reduce load by transferring load that otherwise would be served from the electricity grid to emergency generators. Passive demand resources include on-peak resources, such as energy-efficiency projects and *distributed generation* (DG) that reduce load during predefined periods, and seasonal-peak resources, such as energy-efficiency projects where the project's load reduction is weather sensitive.<sup>117</sup>

In 2012, from January 1 through May 31, the ISO administered two demand-response programs that provided financial incentives for customers to reduce load in response to day-ahead and real-time energy prices: the Real-Time Price-Response (RTPR) Program and the Day-Ahead Load-Response Program (DALRP). An optional program, the Transitional Price-Responsive Demand (TPRD) Program, designed to comply with FERC Order 745 (Demand-Response Compensation in Organized Wholesale Energy Markets), replaced both the RTPR program and

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<sup>116</sup> Potomac Economics, *2013 Assessment of the ISO New England Electricity Markets*, June 25, 2014, [http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind\\_mkt\\_advsvr/ison\\_e\\_2013\\_emm\\_report\\_final\\_6\\_25\\_2014.pdf](http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsvr/ison_e_2013_emm_report_final_6_25_2014.pdf).

<sup>117</sup> Distributed generators are a subset of demand-side resources and consist of relatively small-scale sources of power (i.e., several kilowatts to tens of megawatts in capacity) connected to the grid at the distribution or substation level, not the regional power system. DG technologies include both renewable resources (e.g., solar photovoltaics, wind turbines, fuel cells, biomass, and small hydro) and conventional resources (e.g., diesel reciprocating engines and gas turbines). RTEG is distributed generation the ISO calls on to operate during a 5% voltage reduction that requires more than 10 minutes to implement (i.e., OP 4 Action 6 or more severe actions) but must limit its operation to 600 MW to comply with the generation's federal, state, or local air quality permit(s) and the ISO's market rules.

the DALRP and is currently in effect.<sup>118</sup> Similar to the DALRP, the TPRD program allows market participants with assets registered as RTDR resources to offer load reductions in response to day-ahead LMPs. Market participants are paid the day-ahead LMP for their cleared offers and are obligated to reduce load by the amount cleared day-ahead. The participant is then charged or credited at the real-time LMP for any deviations in curtailment in real-time compared with the amount cleared day-ahead. The TPRD program will remain in effect until June 1, 2017, at which time new market rules will become effective that will fully integrate dispatchable demand resources into the Day-Ahead and Real-Time Energy Markets.<sup>119</sup>

*FERC Order 745 Legal Status.* FERC Order 745 was challenged in 2012 in the D.C. Circuit of the US Court of Appeals. Order 745 requires regional transmission organizations to pay the full LMP for load reductions produced by demand-response resources participating in organized wholesale energy markets subject to certain conditions. The case was argued in front of three judges in September 2013. In May 2014, the D.C. Circuit issued an opinion (by a 2 to 1 vote) vacating the order, stating that, among other things, FERC lacked jurisdiction to promulgate the rules established by Order 745.<sup>120</sup> However, the D.C. Circuit also stayed the mandate to vacate Order 745 pending the outcome of any further appeal to the United States Supreme Court.

In July 2014, FERC asked the D.C. Circuit to rehear the case *en banc*—a request for rehearing before the full 11-member court. In September 2014, the D.C. Circuit denied FERC's request for this rehearing. In January 2015, the US Department of Justice, on behalf of FERC, petitioned the US Supreme Court to review the D.C. Circuit's decision and overturn its ruling. The US Supreme Court will likely decide on whether to hear the case sometime in spring 2015.

Until a final decision is reached on the D.C. Circuit's vacatur of Order 745 the ISO's demand-response rules contained in the tariff will continue to apply. If vacatur ultimately stands, the D.C. Circuit Court's ruling would be remanded to FERC for further action.

### 3.5.2 Demand Resources in the Forward Capacity Market

As shown in Table 3-18, the total CSOs for all demand resources participating in the FCM increased by 19% in 2014 compared with 2013, a gain of 286 MW.<sup>121</sup> The CSOs of passive demand resources accounted for the vast majority of the increase, 240 MW (84%). The increase in the CSOs over the year is mainly attributable to energy-efficiency programs administered by local utilities.

<sup>118</sup> ISO New England Inc., *Order No. 745 Compliance Filing*, FERC Docket No. ER11-4336-001 (August 19, 2011), [http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/er11\\_4336-001\\_prd\\_filing.pdf](http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/er11_4336-001_prd_filing.pdf).

<sup>119</sup> In April 2012, the ISO requested that the transitional rules remain in effect until June 1, 2017, when FCM rules address how capacity resources will be integrated into the energy markets. *ISO New England Inc., Market Rule 1 Price-Responsive Demand FCM Conforming Changes for Full Integration*, Docket No. ER12-1627-000 (filed April 26, 2012), [http://www.iso-ne.com/regulatory/ferc/filings/2012/apr/er12-1627-000\\_4-26-2012\\_prd.pdf](http://www.iso-ne.com/regulatory/ferc/filings/2012/apr/er12-1627-000_4-26-2012_prd.pdf). RTEG resources will be prohibited from participating in the day-ahead and real-time markets because of air permit restrictions.

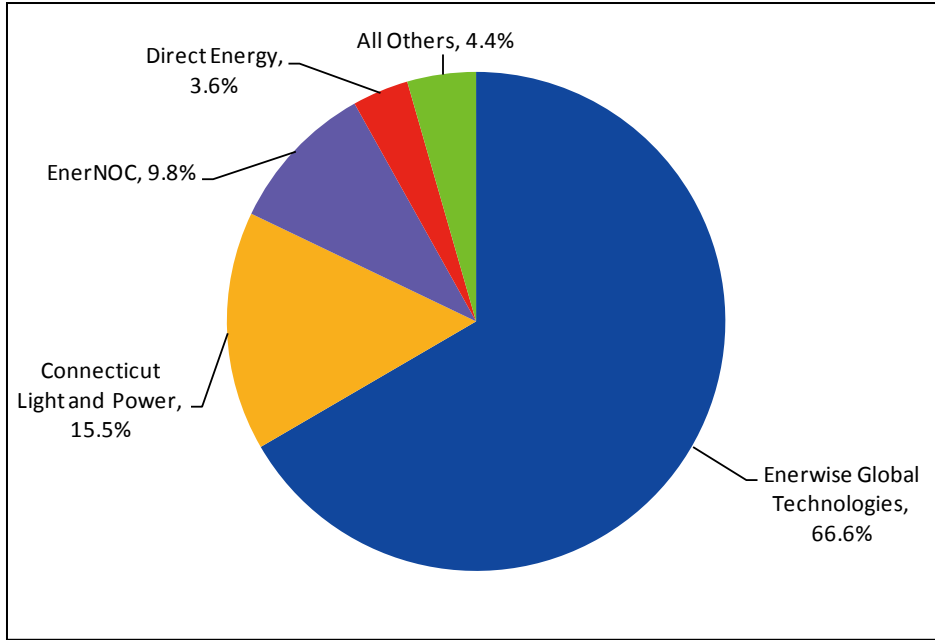
<sup>120</sup> United States Court of Appeals, *Electric Public Supply Association v. FERC* (May 23, 2014), <http://www.cadc.uscourts.gov/internet/opinions.nsf/DE531DBFA7DE1ABE85257CE1004F4C53/%24file/11-1486-1494281.pdf>.

<sup>121</sup> This table shows the net CSO value held by demand resources for December 2013 and December 2014 in time after trading out of obligations awarded in the primary forward capacity auction.

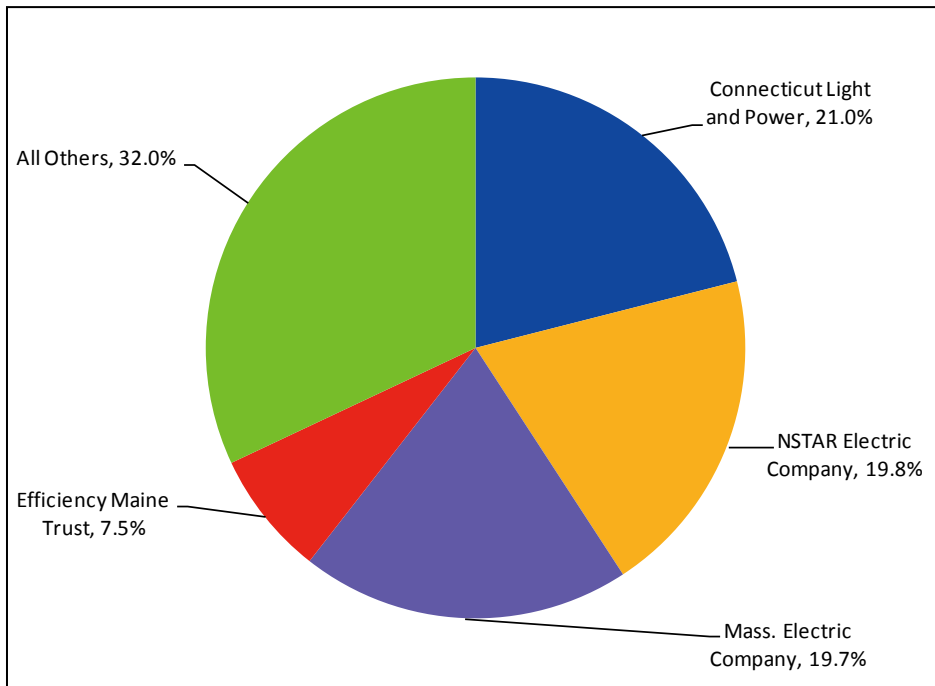
**Table 3-18**  
**Capacity Supply Obligations by Demand-Resource Type, December 2013 and December 2014 (MW)**

	Active Demand Resources			Passive Demand Resources			Total All Demand Resources
	Real-Time Demand Response Resource	Real-Time Emergency Generation Resource	Total Active Demand Resources	On-Peak Demand Resource	Seasonal-Peak Demand Resource	Total Passive Demand Resources	
<b>Dec 2013</b>	268	127	395	812	328	1,140	<b>1,535</b>
<b>Dec 2014</b>	296	145	441	1,033	347	1,380	<b>1,821</b>
<b>2013 to 2014 % change</b>	10%	14%	12%	27%	6%	21%	<b>19%</b>

Figure 3-9 and Figure 3-10 illustrate market participants and their CSO (measured as a percentage of total megawatts) for both active and passive demand resources. Two participants accounted for 82% of the RTDR and RTEG resources. Figure 3-9 illustrates the market participants with active demand resources as of December 2014, as well as the percentage of CSOs (in MW) represented by these participants. These results are similar to December 2013. Figure 3-10 illustrates the market participants with passive demand resources as of December 2014 and the percentage of CSOs represented by these participants. Similar to December 2013, the top two participants accounted for approximately 41% of the total.



**Figure 3-9: Distribution of active demand-resource CSOs (in MW) by lead participant, as of December 2014 (%).**



**Figure 3-10: Distribution of passive demand-resource CSOs (in MW) by lead participant, as of December 2014 (%).**

Typically, the market participants that provide demand-response services offer most of the active demand resources, while the market participants that are investor-owned utilities and part of state-sponsored energy-efficiency programs offer most of the passive demand resources.

### 3.5.3 Demand-Resource Payments

As shown in Table 3-19, demand-resource payments totaled \$90.3 million in 2014 compared with \$87.5 million in 2013, an increase of 3.2%. Capacity payments are based on the FCM capacity clearing price and capacity values determined pursuant to the rules of the FCM. Total demand-resource capacity payments were slightly higher in 2014 compared with 2013. Capacity payment rates (\$/kW-month) were also slightly higher in 2014 relative to 2013.

**Table 3-19**  
**Total Payments to Demand-Response Resources, 2013 and 2014 (\$ Millions)**

Year	Capacity Payments	Transitional PRD Payments	Total Payments
2013	87.5	4.7	92.2
2014	90.3	3.9	94.2
Change	2.8	(0.8)	2.0
% Change 2013 to 2014	3.2%	-17.2%	2.2%

The remainder of the payments to demand resources in 2014, approximately 4%, was for load reductions in the current transitional Price-Responsive Demand Program.

### 3.5.4 2014 Demand-Response Recommendation and Follow Up of 2013 Recommendations

Two recommendations for demand response were made in the *2013 Annual Markets Report*. One recommendation concerned demand-response baselines and their predictive power (accuracy) in forecasting various resource load shapes. The second recommendation addressed third-party verification of meter data submitted by market participants for their demand-response resources.

#### 3.5.4.1 Follow Up and Recommendation on the Methodology for Determining Demand-Resource Baselines

In 2014, the ISO researched various alternative baseline methodologies to improve the accuracy of estimated baselines in predicting actual load shapes. The work performed by the ISO was submitted to an independent consulting firm with expertise in both the power industry and statistical modeling. Currently, the independent consulting firm is reviewing the proposed methodology the ISO submitted, as well as possibly proposing recommendations for further improvements that may be discovered during the review process. The planned implementation date for the new baseline methodology is currently June 1, 2017, at which time new market rules will become effective that will fully integrate dispatchable demand resources into the day-ahead and real-time markets (also see Section 3.5.1). Given the uncertainty in FERC jurisdiction over demand-response participation in energy markets as previously discussed, the ISO's current plan to fully integrate demand response into the energy markets on June 1, 2017, including the implementation of any baseline changes, may need to be modified.

If, and when, the new baseline methodology is implemented, the new methodology's predictive ability in estimating a resource's actual load should be made transparent to the market. The accuracy of the new baseline methodology should be made available to the market by whatever metrics the ISO believes would best describe how well the methodology is performing. While

any methodology will perform better for some demand-response resource load profiles than others, a report reflecting the accuracy over the broad array of resources will give more confidence in the methodology and ultimately its ability to measure load reductions produced by demand-response resources.

#### *3.5.4.2 Follow Up on Third-Party Verification of Meter Data*

A much broader filing with FERC addresses the 2013 AMR's recommendation regarding the validation of meter data from market participants, which becomes effective in capacity commitment periods on and after June 1, 2017.<sup>122</sup> The 5-minute interval meter data reported by the market participant can be from the same revenue-quality meter the distribution company uses for billing purposes. Another requirement is that, if the 5-minute interval meter data from a market participant is *not* from the distribution company's revenue-quality meter used for billing purposes, the market participant must validate and provide documentation to the ISO that the difference between the values recorded by the market participant's meter and the distribution company's billing meter are within  $\pm 2.0\%$ . Linking the participants' submittal data with the local distribution companies' metering should significantly reduce erroneous data submittals.

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<sup>122</sup> *Order Accepting Market Rule Provisions to integrate PRD*, Docket No. ER15-257-000, 001, 002 (filed January 9, 2015), [http://www.iso-ne.com/static-assets/documents/2015/01/er15-257-000-001-002\\_1-9-15\\_order\\_accept\\_rev\\_integrate\\_prd.pdf](http://www.iso-ne.com/static-assets/documents/2015/01/er15-257-000-001-002_1-9-15_order_accept_rev_integrate_prd.pdf).

## Section 4

### Other Market Information

In 2014, the following audits were conducted to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders.

#### 4.1 SOC 1 Type 2 Examination

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In November 2014, the ISO successfully completed a Service Organization Controls (SOC) 1 Type 2 examination, which resulted in an “unqualified opinion” about the description of the market administration and settlements systems. Developed by the American Institute of Certified Public Accountants, the SOC 1 examination covers aspects of a service organization’s systems for processing transactions that may be relevant to a user entity’s internal controls for financial reporting. Entities such as Regional Transmission Organizations complete SOC 1 examinations to assist user entities in evaluating their internal controls over financial reporting.

The ISO’s SOC 1 Type 2 examination is a rigorous examination that entails detailed testing of the business processes and information technology for bidding, accounting, settlement, and billing the market products of electric energy, regulation, transmission, capacity, demand response, reserves, and associated market transactions. The Type 2 examination covered the 12-month period from October 1, 2013, through September 30, 2014. The SOC 1 Type 2 examination reviews the following:

- The fairness of the description of the market administration and settlements systems’ controls designed and implemented throughout the period
- Whether the controls were suitably designed to provide reasonable assurance that the control objectives would be achieved if the controls operated effectively throughout the period and user entities applied the complementary user entity controls contemplated in the design
- The controls tested, which together with the complementary user-entity controls, were those necessary to provide reasonable assurance that the control objectives were achieved throughout the period

The ISO conducts a SOC 1 Type 2 examination annually. The 2014 SOC 1 Type 2 report is available to participants upon request through the ISO external website.<sup>123</sup>

#### 4.2 Market-System Software Recertification

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The ISO has committed to engaging an independent third party, PA Consulting, to review and certify that the market-system software complies with *Market Rule 1*, the manuals, and standard operating procedures.<sup>124</sup> This recertification takes place every two years or sooner, in

<sup>123</sup> KPMG. *Report on Management’s Description of its System and the Suitability of the Design and Operating Effectiveness of Controls Pertaining to the Market Operations and Settlements System for the Period October 1, 2013, to September 30, 2014*. This report is available to participants by request through the ISO external website, <http://www.iso-ne.com/isoexpress/soc-1-type-2-report-request>.

<sup>124</sup> *Market Rule 1*, <http://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1>.

the case of a major market-system enhancement or new market features. After conducting detailed tests and analyses of the applicable mathematical formulations, PA Consulting issues a compliance certificate for each market-system module it audits. The certificates provide assurance that the software is operating as intended and is consistent with *Market Rule 1* and associated manuals and procedures.

In 2014, PA Consulting issued the following certifications:

- Locational Forward Reserve Market Software, July 9, 2014
- Locational Marginal Price Calculator Market Software, June 26, 2014, and December 3, 2014
- Scheduling, Pricing, and Dispatch—Day-Ahead Market Software, January 7, 2014, June 26, 2014, and December 3, 2014
- Scheduling, Pricing, and Dispatch—Unit Dispatch Scheduling Market Software, June 26, 2014, and December 3, 2014
- Forward Capacity Auction Market Clearing Engine Software, December 24, 2014
- Forward Capacity Reconfiguration Auction Clearing Engine Software, July 8, 2014

### **4.3 Internal Audits**

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The ISO New England Internal Audit Department conducted a number of internal controls and compliance audits in the Forward Capacity Market, demand-resource, and information technology areas.

## Acronyms and Abbreviations

Acronyms and Abbreviations	Description
°F	degrees Fahrenheit
AC	alternating current
ACE	area control error
AMR	Annual Markets Report
ARA	annual reconfiguration auction
ARR	Auction Revenue Rights
BAL-001-0	NERC's <i>Real Power Balancing Control Performance Standard</i>
Btu	British thermal unit
C4	four largest competitors
Carry Forward Rule	<i>Capacity Carry Forward Rule</i>
CCGT	combined-cycle gas turbine
CCP	capacity commitment period
CPS 2	NERC <i>Control Performance Standard 2</i>
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CTS	Coordinated Transaction Scheduling
DALRP	Day-Ahead Load Response Program
DFO	dual-fuel override
DG	distributed generation
DOE	US Department of Energy
DOJ	US Department of Justice
ecomax	economic minimum limit
ecomin	economic maximum limit
EIA	US Energy Information Administration (of DOE)
EMM	External Market Monitor
EMOF	Energy Market Offer Flexibility
ERS	external reserve support
F	Fahrenheit
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FPA	fuel-price adjustment
FRM	Forward Reserve Market
FTR	Financial Transmission Right
GPA	generator performance audit
GWh	gigawatt-hour

Acronyms and Abbreviations	Description
HE	hour ending
HHI (also H)	Herfindahl-Hirschman Index
HQ	Hydro-Québec
IC Rule	<i>Insufficient Competition Rule</i>
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
IMM	Internal Market Monitor
ISO	Independent System Operator, ISO New England
ISO tariff	<i>ISO New England Transmission, Markets, and Services Tariff</i>
kW	kilowatt
kWh	kilowatt-hour
kW-mo	kilowatt-month
L	symbol for the competitiveness level of the LMP
LEG	limited-energy generator
LMP	locational marginal price
LNG	liquefied natural gas
LSE	load-serving entity
LSR	local sourcing requirement
M-36	<i>ISO New England Manual for Forward Reserve</i>
MCL	maximum capacity limit
ME	State of Maine and Maine load zone
Min Gen	Minimum Generation (Min Gen Emergency)
M/LCC2	Master/Local Control Center Procedure No. 2, <i>Abnormal Conditions Alert</i>
MMBtu	million British thermal units
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency
NCPC	Net Commitment-Period Compensation
NEL	net energy for load
NEMA	Northeast Massachusetts, Boston load zone
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NH	State of New Hampshire, New Hampshire load zone
NICR	net Installed Capacity Requirement
NPCC	Northeast Power Coordinating Council

Acronyms and Abbreviations	Description
NPR	nonprice retirement request
NY	State of New York
NYISO	New York Independent System Operator
OATT	<i>Open Access Transmission Tariff</i>
OP 4	ISO Operating Procedure No. 4
OP 8	ISO Operating Procedure No. 8
ORP	offer-review price
ORTP	offer-review trigger price
PER	peak energy rent
PFP	pay for performance
PJM	PJM Interconnection, L.L.C.
pnode	pricing node
PRD	price-responsive demand
Q	quarter
QDN	Qualification Determination Notification
RAA	reserve adequacy analysis
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RI	State of Rhode Island, Rhode Island load zone
RSI	Residual Supply Index
RTDR	real-time demand response
RTEG	real-time emergency generation
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTPR	real-time price response
SEMA	Southeast Massachusetts load zone
SOC 1	present audit of market operations and settlement systems
SWCT	Southwest Connecticut
TMNSR	10-minute non-spinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TPRD	transitional price-responsive demand
TTC	total transfer capability
US	United States
VT	Vermont and Vermont load zone
WCMA	Western/Central Massachusetts

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# ISO New England's Internal Market Monitor

First Quarter 2015

Quarterly Markets Report

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June 9, 2015

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## Section 1

### Executive Summary

The Internal Market Monitor<sup>1</sup> has analyzed the performance in the first quarter (“Q1”) of 2015 (the “Reporting period”) of the region’s wholesale electric energy, ancillary services, and capacity markets using supply offers, demand bids, fuel prices, market results, and other economic data. Overall, market prices reflected the cost of providing energy, and energy market outcomes were competitive.<sup>2</sup>

#### 1.1 Summary of Market Outcomes and Performance

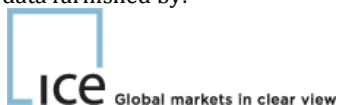
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- The total estimated wholesale market costs in the Reporting Period were \$3.14 billion, a 41% decrease compared to the same period in 2014 (Q1 2014).
  - Lower natural gas prices were the primary driver for the decrease in total energy costs in the Reporting Period. Natural gas prices during the Reporting Period averaged \$11.37/MMBtu. This is a 43% decrease from Q1 2014.
- Day-Ahead Energy Market prices during the Reporting Period averaged \$84.84/MWh at the Hub, and Real-Time prices averaged \$81.97/MWh. Day-Ahead prices were 41% lower than Q1 2014, and Real-Time prices were 43% lower than Q1 2014.
- Total real-time reserve payments were \$2.9 million in the Reporting Period, an 80% decrease from Q1 2014, and Regulation payments totaled \$7.0 million, a 56% decrease from Q1 2014.
- Total Net Commitment Period Compensation (“NCPC”) payments during the Reporting Period totaled \$36.0 million, a 67% decrease from Q1 2014.
- Overall, the energy market was competitive during the Reporting Period. The system-wide concentration of supply ownership remains low. Energy market prices are consistent with input costs.

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<sup>1</sup> Capitalized terms used but not defined in this report are intended to have the meanings given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff (“ISO Tariff”) or in ISO operating procedures. The ISO Tariff is available at [www.iso-ne.com/regulatory/tariff/index.html](http://www.iso-ne.com/regulatory/tariff/index.html). Market Rule 1 is Section III of the ISO Tariff.

<sup>2</sup>This report fulfills the requirement of Market Rule 1, Appendix A, Section III.A.17.2.2, *Market Monitoring, Reporting, and Market Power Mitigation*. Some data presented in this report are still open to resettlement. Underlying natural gas data furnished by:



- The ISO implemented Energy Market Offer Flexibility (“EMOF”) changes on December 3, 2014. EMOF allows market participants to vary energy market offers by hour and to change offers in real time during the Operating Day. The IMM has reviewed aspects of EMOF and found that generators are utilizing the flexibility afforded by the rule changes. Generators are now using price more frequently, and changing price across hours, to signal changes to underlying variable production and opportunity costs. There has been a reduction in the volume of self scheduling in which generators assume a price-taking role and to the extent to which generators vary Economic Minimum parameters to reach desired levels of output. Negative offers have also resulted in a greater frequency of negative pricing in the market. The results of that review are in Section 3.
- The ninth Forward Capacity Auction (FCA 9) was held on February 2, 2015. Conditions existed which caused the capacity zones and external interfaces to close at different rounds and prices. The IMM concluded that the outcome of the auction system-wide was competitive, and no anti-competitive behavior was evident. See Section 4 for a discussion of the ninth FCA.

## Section 2

# Summary of Market Outcomes and System Conditions

This section summarizes the region's wholesale electricity market outcomes and measures of market performance and competitiveness from January 1, 2015 through March 31, 2015 (the "Reporting Period").

### 2.1 Market Outcomes

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#### 2.1.1 Total Wholesale Electricity Market Value

Figure 2-1 and Figure 2-2 show the estimated wholesale electricity market cost by month and quarter (in billions of dollars) by market and average natural gas prices (in \$/MMBtu) in Q1 2015 compared with Q1 2014 and Q4 2014. In Q1 2015 the total estimated market cost decreased by about 41% compared to Q1 2014 (\$3.14 billion compared to \$5.29 billion), and increased by 99% when compared to Q4 2014 (\$1.57 billion).<sup>3</sup> Net Commitment Period Compensation (NCPC) costs in Q1 2015, at \$36 million, increased by 26% compared to Q4 2014 but decreased by 67% compared to Q1 2014. Ancillary service costs which include reserve and regulation payments totaled \$48 million, a decrease of 16% and 5% when compared to both Q1 and Q4 2014, respectively.

As shown in Figure 2-1 and Figure 2-2 below, natural gas prices were the primary driver behind changes in energy costs. As noted in the *2014 Annual Markets Report*, very cold weather throughout the first quarter (January-March) of 2014 resulted in high demand for natural gas and consequently high natural gas prices.<sup>4</sup> Natural gas pipeline conditions were tight and price was sufficiently high during this period that, at times, other fuel types, in particular oil were more economic which resulted in fuel switching among resources. The wholesale cost of electricity during the 2014/15 winter period was significantly lower compared to the previous winter due primarily to lower oil prices, the increase in gas supply from Canada and from within the region from Liquefied Natural Gas and the resulting downward pressure on natural gas prices.<sup>5</sup>

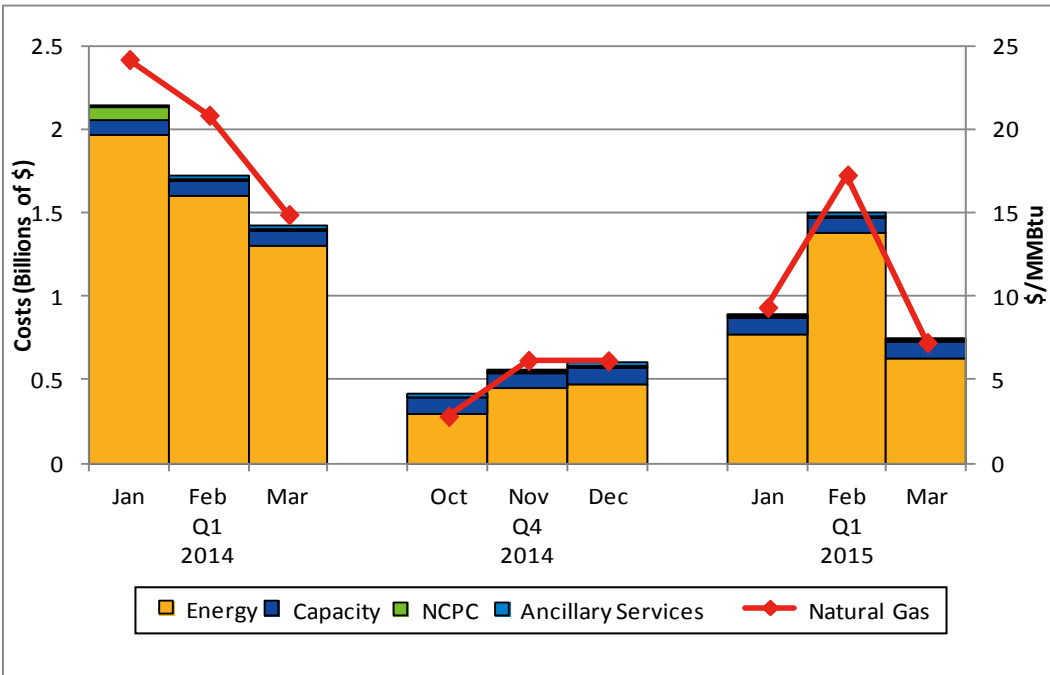
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<sup>3</sup> The total cost of electric energy is approximated as the product of the real-time load obligation for the region and the average real-time locational marginal price ("LMP"). The real-time load obligation is the requirement that each market participant has for providing electric energy at each location (i.e., node, load zone or the Hub) equal to the amount of load it is serving, including external and internal bilateral transactions. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of annual wholesale costs.

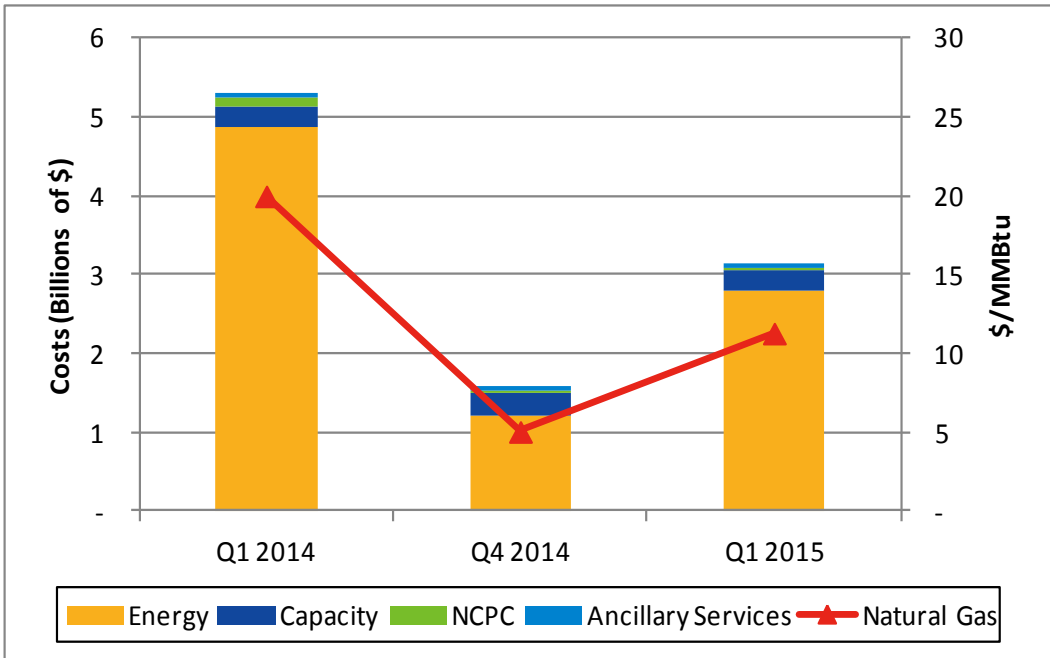
<sup>4</sup>ISO New England, *2014 Annual Markets Report* (May 20, 2015), <http://www.iso-ne.com/static-assets/documents/2015/05/2014-amr.pdf>.

<sup>5</sup> EIA, *Natural Gas Weekly Update, January 21, 2015* (January 22, 2015), [http://www.eia.gov/naturalgas/weekly/archive/2015/01\\_22/index.cfm](http://www.eia.gov/naturalgas/weekly/archive/2015/01_22/index.cfm).

**Figure 2-1: Wholesale market costs and average natural gas prices by month during Quarter 1 2014, Quarter 4 2014, and Quarter 1 2015 (\$ and \$/MMBtu)**



**Figure 2-2: Wholesale market costs and average natural gas prices by quarter, for Quarter 1 2014, Quarter 4 2014, and Quarter 1 2015 (\$ and \$/MMBtu)**



### 2.1.2 Key Market Statistics

Table 2-1 shows selected key statistics for loads, Real-Time and Day-Ahead Energy Market prices, and fuel prices.

**Table 2-1: Key Statistics on Load, LMPs, and Natural Gas**

	Q1 2015	Q4 2014	Percent Change Q1 2015 to Q4 2014	Q1 2014	Percent Change Q1 2015 to Q1 2014
<b>Real-Time Load (GWh)</b>	33,578	30,604	10%	33,528	0%
<b>Weather Normalized Real-Time Load (GWh)</b>	32,440	30,664	6%	32,804	-1%
<b>Peak Real-Time Load (MW)</b>	20,556	19,812	4%	20,887	-2%
<b>Average Day-Ahead Hub LMP (\$/MWh)</b>	84.84	40.90	107%	144.99	-41%
<b>Average Real-Time Hub LMP (\$/MWh)</b>	81.97	39.27	109%	143.66	-43%
<b>Average Natural Gas Price (\$/MMBtu)</b>	11.37	5.02	126%	19.95	-43%

The following factors contributed to market outcomes in the Reporting Period when compared to the corresponding quarter of last year:

- Lower natural gas prices in the first quarter of 2015 was the primary driver for lower day-ahead and real-time prices when compared to the same quarter last year.
  - Natural gas prices during the Reporting Period decreased by 43% from Q1 2014.
  - Oil prices were 51% lower during the Reporting Period compared to Q1 2014.
- Real-Time LMPs were 43% lower and Day-Ahead LMPs were 41% lower than prices observed in Q1 2014.
- The Real-Time Load in Q1 2015 was comparable to the Real-Time load in Q1 2014.
- The peak Real-Time Load, which occurred on January 8, 2015 during the Reporting Period, was 20,556 MW, 2% lower than the peak load observed in Q1 2014.

### 2.1.3 Winter Weather Comparison and Fuel Prices

Temperature is a key driver of natural gas prices in New England due to the increasing reliance on the fuel to meet heating needs. Average New England temperatures in the Reporting Period were colder than in Q1 2014 with February 2015 the coldest of the three months. Average monthly temperatures for January, February and March were 23.4, 16.6 and 32.0 degrees Fahrenheit, respectively, in 2015 compared to 24.2, 25.6 and 30.9 degrees in 2014. February 2015, on average, was 9 degrees colder than February 2014. Figure 2-3 illustrates over the 28-day period how many days the average daily temperature fell into defined temperature ranges.<sup>6</sup>

<sup>6</sup> As an example, in 2015 there were 16 days where the average daily temperature was between 10 and 19 degrees, while in 2014 there were only 8 days that fell in that temperature range. Also, in 2015 there were three days in February where the average daily temperature was below 10 degrees.

**Figure 2-3: February average daily temperatures (degrees Fahrenheit), 2014 and 2015**

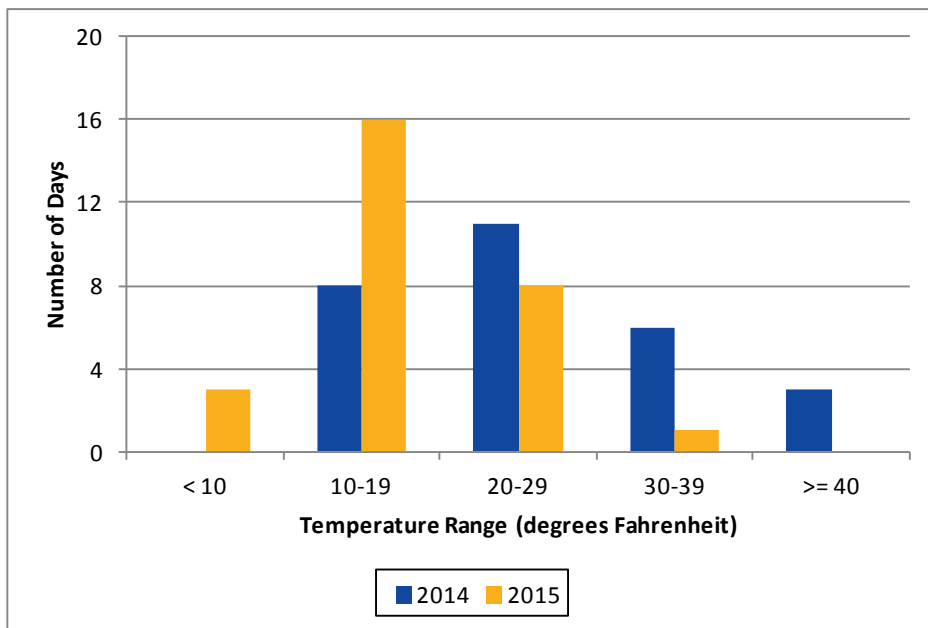
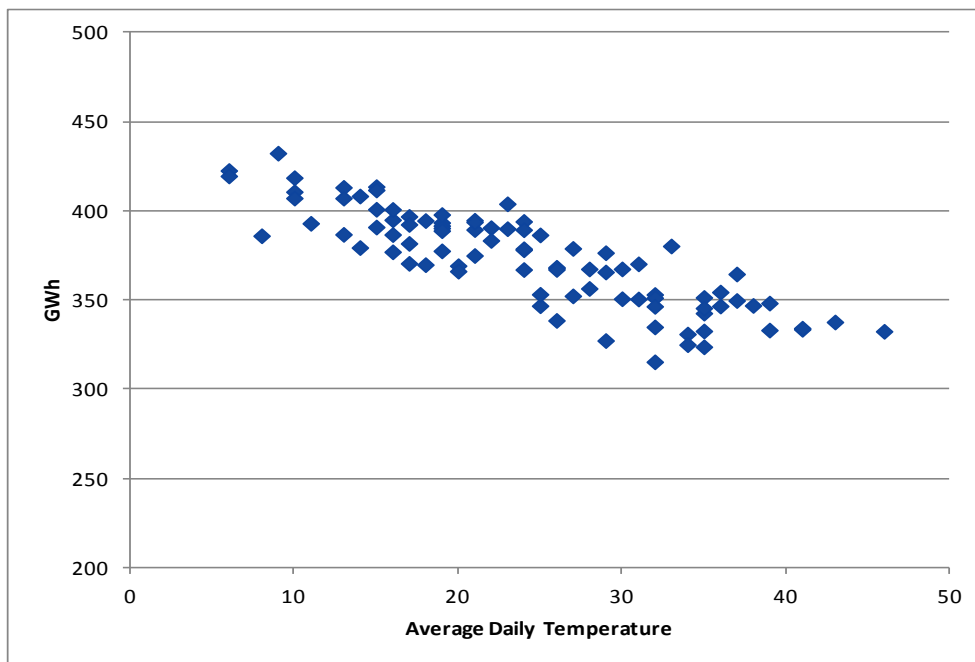


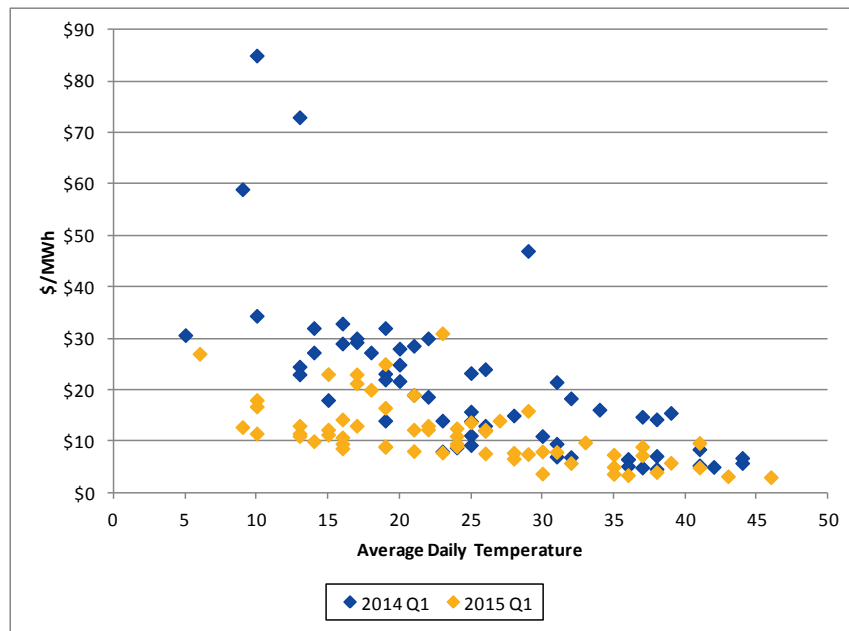
Figure Figure 2-4: New England daily energy from January 1 through March 31, 2015 below shows the relationship between New England daily energy and average temperature for days in the Reporting Period. As expected in winter months, there is an inverse relationship between temperature and load – lower average daily temperatures typically results in higher electricity usage.

**Figure 2-4: New England daily energy from January 1 through March 31, 2015**



Despite colder temperatures during the first quarter 2015, gas prices were lower and less volatile in the Reporting Period when compared to Q1 2014. Figure 2-5 below displays the median daily trade prices for Algonquin next-day trades compared with the average daily temperature for the first quarter for 2014 and 2015.<sup>7</sup> The median daily trade prices in the Reporting Period, given similar temperatures, are not only less volatile but also lower than the first quarter of 2014.

**Figure 2-5: Algonquin next-day trades (median daily price) for the first quarter 2014 and 2015**



The colder weather impacts on the price of natural gas were negated by increases in the supply of natural gas to and from within New England over the course of the winter. The main sources for the increase in natural gas supply include LNG and pipeline imports from Canada.<sup>8</sup>

From Q1 2014 to Q1 2015, there was an increase of over 121%, or more than an 18 bcf, in natural gas from LNG facilities injected into the interstate pipeline system in New England. To put this into context, the increase equates to approximately an additional 1,000 MW each hour of gas generation over the quarter (assuming an average heat rate of 8,000 Btu/KWh).

The increase in LNG has come from several pipeline receipt points in New England including Distrigas (Distrigas Receipt), Everett Int. (Middlesex, MA), Excelerate Energy LP (Essex, MA), and Canaport (Maritimes/Brunswick Pipeline), with the largest increase in capacity coming from Everett Int. In addition, Excelerate Energy LP (Essex, MA) supplied LNG during Q1 2015, compared to Q1 2014 where they did not supply any LNG. See Table 2-2.

<sup>7</sup> For example, if there were 25 trades for Algonquin next-day products, the price displayed for that day would be the median trade value of the 25 trades.

<sup>8</sup> EIA, *Natural Gas Weekly Update, January 21, 2015* (January 22, 2015), [http://www.eia.gov/naturalgas/weekly/archive/2015/01\\_22/index.cfm](http://www.eia.gov/naturalgas/weekly/archive/2015/01_22/index.cfm).

**Table 2-2: LNG Scheduled Capacity Data, Q1 2014 v. Q1 2015 (MMBtu)**

Source	Q1 2014	Q1 2015	Change
Distrigas Receipt	233,857	3,629,944	<b>3,396,087</b>
Everett Int. (Middlesex, MA)	2,013,712	8,686,404	<b>6,672,692</b>
Excelerate Energy LP (Essex, MA)	0	2,675,821	<b>2,675,821</b>
Maritimes/Brunswick Pipeline	12,725,774	18,118,920	<b>5,393,146</b>
<b>Total</b>	<b>14,973,343</b>	<b>33,111,089</b>	<b>18,137,746</b>

Source: Genscape

As gas price decreased by 43% in the Reporting Period compared to the Q1 2014 oil prices experienced a comparable decline of just over 50%.

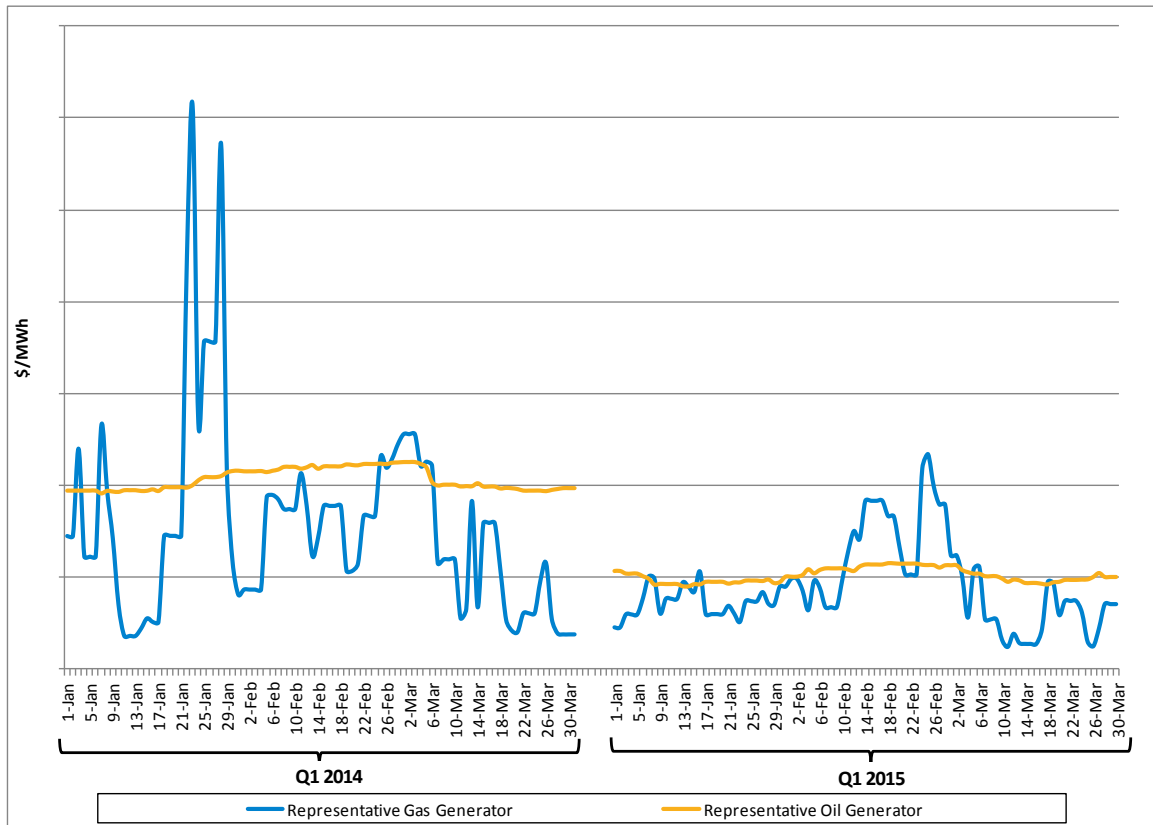
Figure 2-6 below shows the relationship between daily natural gas and oil generation costs over Q1 of 2014 and the Reporting Period.<sup>9</sup> The generation costs are calculated using daily natural gas and oil prices and an assumed heat rate of 7,800 Btu/kWh and 10,000 Btu/kWh for gas and oil, respectively.

Figure 2-6 also shows the marked decrease in both natural gas and oil prices between the two quarters. While natural gas exceeded oil for 24 days in Q1 2015 compared to 19 days in Q1 2014, the figure also shows that the price difference between gas and oil was smaller in the Reporting Period compared to Q1 2014. For instance, gas and oil generation costs were within 10% of each other on 15 days in Q1 2015 compared to 11 days in Q1 2014.

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<sup>9</sup> Prices are not shown on the vertical axis due to contractual restrictions with the providers of our oil data, Argus.

Figure 2-6: Natural gas and oil generation costs of representative generators during Quarter 1 2014 and Quarter 1 2015 (\$/MWh)



## 2.1.4 Real-Time Markets

### 2.1.4.1 Real-Time Energy Market

In the Reporting Period, the average real-time Hub price was \$81.97/MWh, down 43% from \$143.66/MWh in Q1 2014.<sup>10</sup> The decrease in price was primarily driven by lower natural gas prices (see Figure 2-1 and Table 2-1). Price differences among the load zones stemmed primarily from marginal losses, with little zonal congestion.<sup>11</sup> Congestion was restricted primarily to smaller, more transient load pockets that formed when transmission or generation elements were out of service. The Maine zone had lower average pricing (\$76.75/MWh) than other load zones, as it is an export-constrained area with lower cost generating resources than other load zones. See Table 2-3.

<sup>10</sup> Throughout this report, average prices are calculated using a simple average method.

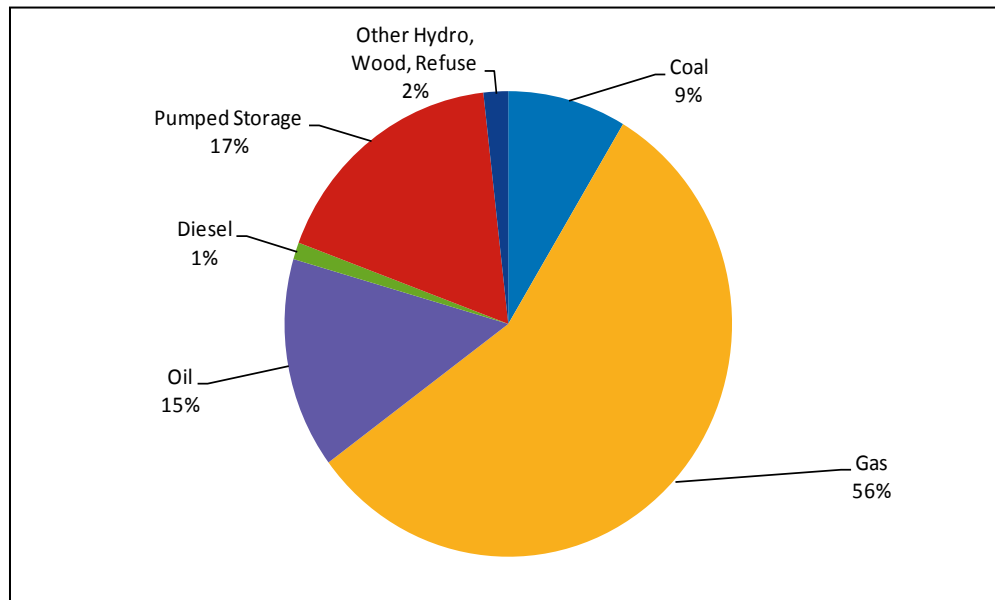
<sup>11</sup> A *load zone* is an aggregation of load pricing nodes (pnodes) within a specific area. The loss component of the LMP is the marginal cost of additional losses caused by supplying an increment of load at the location.

**Table 2-3: Simple Average Real-Time Hub and Load Zone Prices (\$/MWh)**

Location/Load Zone	Q1 2015	Q4 2014	Percent Change Q1 2015 to Q4 2014	Q1 2014	Percent Change Q1 2015 to Q1 2014
<b>Hub</b>	\$81.97	\$39.27	109%	143.66	-43%
<b>Maine (ME)</b>	\$76.75	\$37.22	106%	130.74	-41%
<b>New Hampshire (NH)</b>	\$79.25	\$38.47	106%	137.52	-42%
<b>Vermont (VT)</b>	\$79.98	\$38.07	110%	139.25	-43%
<b>Connecticut (CT)</b>	\$80.36	\$38.89	107%	142.03	-43%
<b>Rhode Island (RI)</b>	\$82.04	\$39.22	109%	144.05	-43%
<b>Southeast Massachusetts (SEMA)</b>	\$82.42	\$39.37	109%	144.23	-43%
<b>Western Central Massachusetts (WCMA)</b>	\$81.72	\$39.20	108%	143.47	-43%
<b>Northeast Massachusetts (NEMA)</b>	\$82.75	\$39.67	109%	144.57	-43%

In the Reporting Period, units burning natural gas were marginal for 56% of the pricing intervals, followed by pump storage units (including pumping demand), which were marginal in 18% of pricing intervals. Coal units were marginal in 9% of the pricing intervals. Units burning oil, diesel, jet fuel, or wood along with traditional hydro units were marginal in the remaining pricing intervals. See Figure 2-7: Marginal units by fuel type, Quarter 1 2015

**Figure 2-7: Marginal units by fuel type, Quarter 1 2015**



#### 2.1.4.2 Real-Time Operating Reserves

In the Reporting Period, the total real-time reserve payments were \$2.9 million; an 80% decrease relative to Q1 2014's \$14.7 million of payments.<sup>12</sup> The total payment reduction from Q1 2014 was primarily the result of lower nonzero pricing frequencies for both TMNSR and TMOR and reduced prices for TMSR. More zero pricing and lower TMSR pricing were the result of different system conditions in the Reporting Period.

Real-time reserve payments also decreased from Q4 2014 to Q1 2015, which is also the result of decreased nonzero pricing frequencies for TMNSR and TMOR and reduced prices for TMSR. See Table 2-4.

**Table 2-4: Real-Time Reserve Payments (\$ and %)**

	Q1 2015	Q4 2014	Percent Change Q4 2015 to Q4 2014	Q1 2014	Percent Change Q1 2015 to Q1 2014
<b>Systemwide TMSR</b>	1,480,492	3,998,731	-63%	4,377,913	-66%
<b>Systemwide TMNSR</b>	1,176,064	2,956,827	-60%	7,507,448	-84%
<b>Systemwide TMOR</b>	45,394	233,178	-81%	940,689	-95%
<b>SWCT TMOR</b>	121,688	542,805	-78%	1,367,631	-91%
<b>CT TMOR</b>	17,803	80,214	-78%	257,712	-93%
<b>NEMA-Boston TMOR</b>	48,357	150,506	-68%	220,386	-78%
<b>Total</b>	<b>2,889,798</b>	<b>7,962,261</b>	<b>-64%</b>	<b>14,671,779</b>	<b>-80%</b>

<sup>12</sup> Payment data represent total payments for real-time reserves, and are not net of settlement adjustments for forward reserve obligation charges.

### 2.1.4.3 Regulation Market

Total Regulation Market payments during the Reporting Period were \$7.0 million, down 56% from \$15.8 million in Q1 2014, and up 20% from \$5.8 million in Q4 2014. The decrease in regulation payments as compared with Q1 2014 is mainly attributable to the decrease in natural gas prices in the Reporting Period.

### 2.1.5 Forward Markets

#### 2.1.5.1 Day-Ahead Energy Market

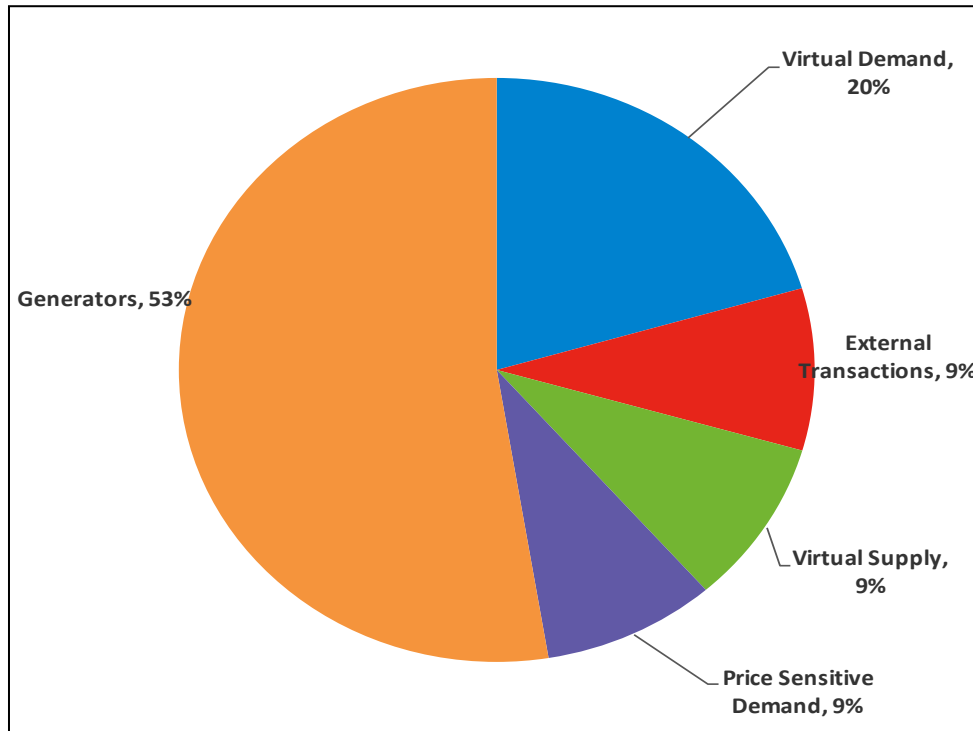
The average day-ahead Hub price in the Reporting Period was \$84.84/MWh, down 41% from \$144.99/MWh in Q1 2014. As in real-time, the decrease in price was primarily driven by lower natural gas prices (see Figure 2-1 and Table 2-1). This price is consistent with observed market conditions. Price differences among the load zones stemmed primarily from marginal losses, with little congestion at the zonal level. Congestion was restricted primarily to smaller, more transient load pockets that formed when transmission or generation elements were out of service. See Table 2-5.

**Table 2-5: Simple Average Day-Ahead Hub and Load Zone Prices (\$/MWh)**

Location/Load Zone	Q1 2015	Q4 2014	Percent Change Q1 2015 to Q4 2014	Q1 2014	Percent Change Q1 2015 to Q1 2014
<b>Hub</b>	\$84.84	\$40.90	107%	144.99	-41%
<b>Maine (ME)</b>	\$81.15	\$39.45	106%	138.38	-41%
<b>New Hampshire (NH)</b>	\$83.88	\$40.71	106%	143.51	-42%
<b>Vermont (VT)</b>	\$83.25	\$39.98	108%	143.59	-42%
<b>Connecticut (CT)</b>	\$82.74	\$40.64	104%	142.84	-42%
<b>Rhode Island (RI)</b>	\$85.18	\$41.29	106%	146.09	-42%
<b>Southeast Massachusetts (SEMA)</b>	\$85.77	\$41.18	108%	145.51	-41%
<b>Western Central Massachusetts (WCMA)</b>	\$84.78	\$40.90	107%	145.11	-42%
<b>Northeast Massachusetts (NEMA)</b>	\$85.75	\$41.46	106%	145.36	-41%

As shown in Figure 2-8, generators set price approximately 53% of the time in the Reporting Period in the day-ahead market. Virtual transactions set price approximately 29% of the time. In comparison, generators set price 47% of the time and virtual transactions set price 32% of the time in the day-ahead market in Q1 2014.

**Figure 2-8: Percentage of price setting in the day-ahead market, Quarter 1 2015**



In the Reporting Period, submitted virtual demand bids and virtual supply offers totaled approximately 7,328 GWh, a decrease of 35% when compared with Q4 2014. Cleared virtual transactions decreased by 14% compared with Q4 2014. Submitted virtual transactions increased by 65% when compared to Q1 2014, which was the result of three participants offering virtual transactions to external nodes. Cleared virtual transactions decreased slightly (4%). See Table 2-6.

**Table 2-6: Total Submitted and Cleared Virtual Transactions, (GWh)**

	Q1 2015	Q4 2014	Percent Change Q1 2015 to Q4 2014	Q1 2014	Percent Change Q1 2015 to Q1 2014
<b>Total Submitted Virtual Transactions</b>	7,328	11,324	-35%	4,452	65%
<b>Total Cleared Virtual Transactions</b>	912	1,064	-14%	954	-4%
<b>Cleared as % of Submitted</b>	12%	9%	-25%	21%	-42%

### 2.1.5.2 Financial Transmission Rights

Three Financial Transmission Rights (“FTR”) auctions were conducted during the Reporting Period for a combined total of 123,253 MW of FTR transactions. The total amount distributed as Auction Revenue Rights (“ARRs”) was \$2.7 million. Thirty-one bidders in January, thirty-two bidders in February and thirty-five bidders in March participated in the monthly auctions for the quarter. The level of participation was consistent with prior auctions.

2.1.5.3 Forward Capacity Market

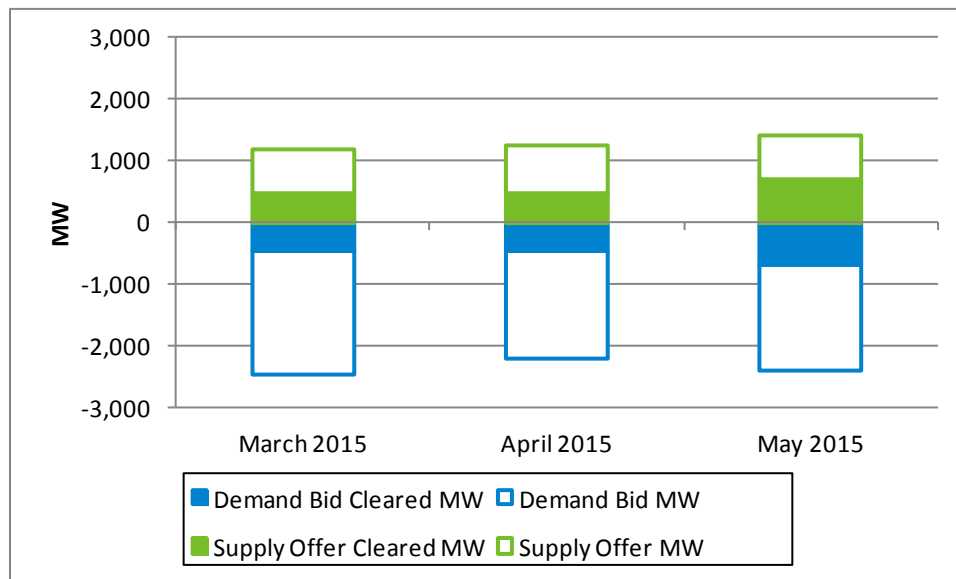
The ninth Forward Capacity Auction (FCA), an annual reconfiguration auction, and several monthly reconfiguration auctions were conducted and contracts bilaterally traded during the Reporting Period. Monthly reconfiguration auctions and bilateral trades for the months of March 2015, April 2015, and May 2015 took place during the Reporting Period.

*Ninth FCA.* FCA 9 was conducted during the Reporting Period on February 2, 2015. See Section 4 for a review of FCA 9.

*Annual reconfiguration auction.* The third annual reconfiguration auction for the 2015-2016 commitment period was conducted during the Reporting Period. The auction cleared 320 MW in capacity with a price of \$11.45/kW-month, the result of mandatory demand bids placed in the auction at the cap by the ISO. This was 233% or \$8.02/kW-month greater than the clearing price in the primary auction for that commitment period.

*Monthly reconfiguration auctions.* Figure 2-9 below shows bid/offered and cleared MWs by monthly auction. The reconfiguration auctions cleared at \$1.50, \$0.70, and \$1.00 per kW-month during each month, with cleared capacity in each auction being 478 MW, 472 MW, and 689 MW for March 2015, April 2015, and May 2015, respectively.

**Figure 2-9: Bid/Offered and Cleared MW, March-May 2015 Monthly Reconfiguration Auctions**



*Bilateral contract periods.* Table 2-7 below shows acquired and transferred MW by resource type for the three bilateral trading periods in the Reporting Period. Exchanged MWs in the bilateral trading periods ranged from 17 to 230 MW. Two generating resources acquired 190 MW in bilateral trades from imports in the May bilateral trading period. Average prices for the bilateral trading periods ranged from \$1.85/kW-month to \$2.34/kW-month.

**Table 2-7: Acquired and Transferred MW for the March-May 2015 Bilateral Contract Periods**

Month	Resource Type	Acquired MW	Transferred MW	Net MW
March 2015	Demand Response	4	34	(30)
	Generator	34	4	30
<b>March 2015 Total</b>		<b>37<sup>13</sup></b>	<b>37</b>	<b>(0)</b>
April 2015	Demand Response	9	14	(5)
	Generator	8	3	5
<b>April 2015 Total</b>		<b>17</b>	<b>17</b>	<b>0</b>
May 2015	Demand Response	9	37	(28)
	Generator	221	3	218
	Import	-	190	(190)
<b>May 2015 Total</b>		<b>230</b>	<b>230</b>	<b>(0)</b>
<b>Total Q1 2015</b>		<b>284</b>	<b>284</b>	<b>(0)</b>

## 2.2 System Conditions

### 2.2.1 Net Commitment Period Compensation

Total Net Commitment Period Compensation (“NCPC”) payments during the Reporting Period totaled \$36.0 million, which includes both reliability NCPC payments and Generator Performance Audit (“GPA”) NCPC payments. NCPC reliability payments during the Reporting Period accounted for most of the payment, while GPA NCPC payments totaled \$31,000.

The majority of NCPC incurred during the Reporting Period was for first contingency.<sup>14</sup> Reliability NCPC payments increased by 28% when compared to last quarter but declined by 67% when compared to Q1 2014.<sup>15</sup> When expressed as a percentage of total energy, NCPC costs were relatively consistent across these periods. Specifically, NCPC costs as a percentage of total energy costs were 1.3%, 2.2%, and 2.1% for Q1 2015, Q4 2014, and Q1 2014, respectively. See Table 2-8.

<sup>13</sup> Sum of individual components do not match subtotal due to rounding.

<sup>14</sup> *Economic/first contingency NCPC payments* include:

- Reliability costs paid for generation committed and dispatched to provide energy on short notice and create operating reserves that allow the system to recover from the loss of the first contingency within the specified period
- Reliability costs paid for the commitment and dispatch of generation to provide systemwide stability or thermal support or to meet systemwide electric energy needs during the daily peak hours
- Reliability costs incurred for generation committed for peak hours but are still on line after the peak hours to satisfy minimum run-time requirements

<sup>15</sup> Reliability NCPC payments include economic/first contingency payments, *local second-contingency NCPC payments* (reliability costs paid to generating units providing capacity in constrained areas), *voltage reliability NCPC payments* (reliability costs paid to generating units dispatched by the ISO to provide reactive power for voltage control or support), and *distribution reliability NCPC payments* (reliability costs paid to generating units that are operating to support local distribution networks).

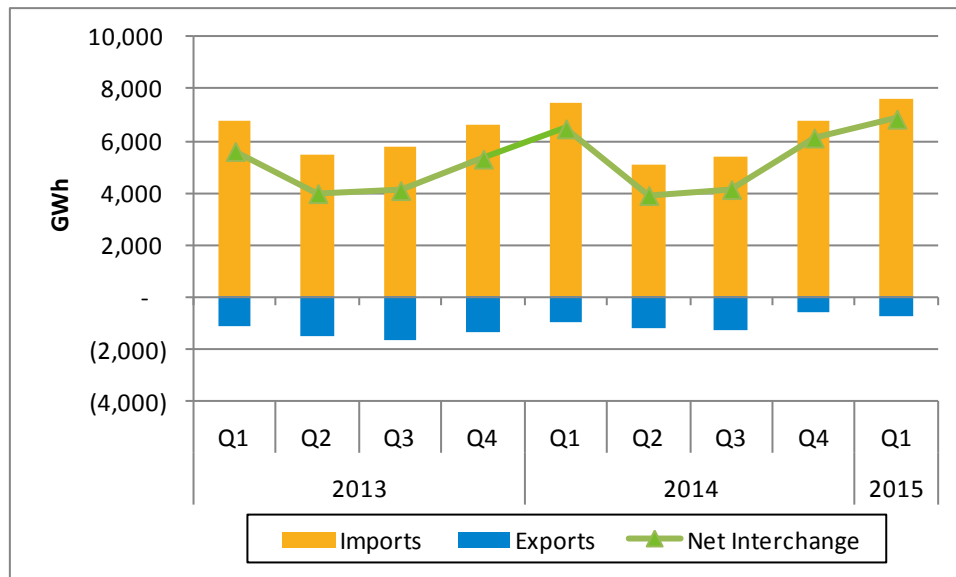
**Table 2-8: NCPC Payments by Quarter and Category (\$)**

	Q1 2015	Q4 2014	Q1 2014
<b>Economic (i.e., First Contingency) Payments</b>	\$27,180,289	\$17,710,980	\$100,715,556
<b>Second Contingency Payments</b>	\$6,334,738	\$8,703,837	\$5,911,018
<b>Voltage Payments</b>	\$2,415,229	\$1,527,817	\$980,917
<b>Distribution Payments</b>	\$22,317	\$1,929	\$93,549
<b>Total</b>	<b>\$35,952,574</b>	<b>\$27,944,562</b>	<b>\$107,701,041</b>

**2.2.2 Net Interchange**

In the Reporting Period, New England was a net importer of power. Net imports from Canada exceeded net exports to New York. Net interchange with neighboring balancing authority areas totaled 6,850 GWh for the Reporting Period, a 12% increase compared with Quarter 4 2014 and a 6% increase when compared to Quarter 1 2014. As shown in Figure 2-10 below, the IMM notes that net interchange has been seasonal in nature, with higher imports occurring during the winter months over the past few years. The increase in net interchange in Q4 2014 was partially due to the loss of a transmission facility between New England and New York that is predominantly a net exporter of power to New York.

**Figure 2-10: Imports, Exports, and Net Interchange, Quarter 1 2013-Quarter 1 2015 (GWh)**



## 2.3 Market Competitiveness

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The Internal Market Monitor calculated the following performance metrics to assess the competitiveness of the wholesale electricity market. Based on the results of the HHI and RSI metrics, the Internal Market Monitor has concluded that the energy market was competitive during the Reporting Period. System-wide concentration remains low. Energy market prices are consistent with costs.

- The *Herfindahl-Hirschman Index* (“HHI”) is a commonly used measure of market concentration. The HHI is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers.<sup>16</sup> The HHI takes into account the relative size distribution of the firms in a market. It approaches zero when a market is occupied by a large number of firms of relatively equal size and reaches its maximum of 10,000 points when a market is controlled by a single firm. The HHI increases both as the number of firms in the market decreases and as the disparity in size between those firms increases.<sup>17</sup> The IMM calculated the HHI for the reporting period and results indicate that the wholesale electric energy markets in New England are well within the “not concentrated” range.<sup>18</sup>
- Table 2-9 summarizes the results of the HHI analysis. The median HHI calculated using the value corresponding to each day’s peak hour is 563 and the median HHI calculated using the value corresponding to each day’s lowest load hour is 674. Using the DOJ’s *Horizontal Merger Guidelines*, the Real-Time Energy Market in New England is not concentrated. In general, the HHI is higher in low-load hours than peak hours. During low-load hours, large baseload units meet much of the demand. These baseload units are owned by a few participants, which increases the market concentration. During peak load hours, more resources owned by additional participants enter the market, lowering the market share of the participants that control the majority of baseload resources, as well as the overall market concentration. This was evident in Q1 2015, when the top-four participants (by market share) comprised 44% of the market in the hours with the lowest load, compared with 37% for the peak hours.

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<sup>16</sup> The HHI is calculated as follows:

$$H = \sum_{i=1}^N s_i^2$$

where  $s_i$  is the market share of firm  $i$  in the market, and  $N$  is the number of firms. The Herfindahl Index ( $H$ ) ranges from  $1/N$  to one, where  $N$  is the number of firms in the market. Equivalently, if percents are used as whole numbers, as in 75 instead of 0.75, the index can range up to  $100^2$ , or 10,000.

<sup>17</sup> The Department of Justice defines markets with an HHI below 1,500 points to be unconcentrated, an HHI between 1,500 and 2,500 points to be moderately concentrated, and an HHI above 2,500 points to be highly concentrated. US Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines* (Washington, DC: US Department of Justice and Federal Trade Commission, August 19, 2010), <http://www.justice.gov/atr/public/guidelines/hmg-2010.html>.

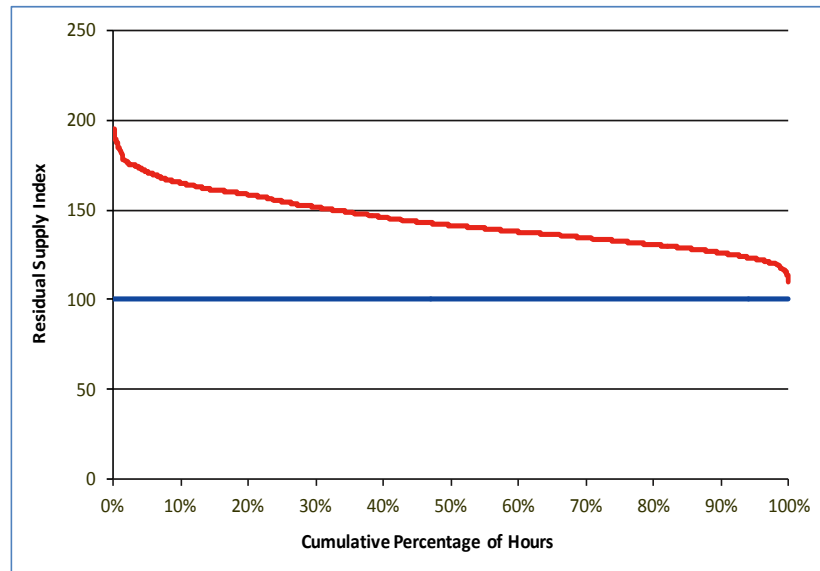
<sup>18</sup> HHI ignores transmission constraints and contractual entitlements to generator output, which would have the effect of increasing and decreasing concentration, respectively. The net effect has not been measured; however, given the low level of overall concentration even if these effects produced a net increase in concentration, the impact would not change our assessment.

**Table 2-9: Median and Maximum HHI, Median Hourly Load, Number of Participants, and Share of Top Participants (by Market Share) for Each Day’s Peak-Load and Lowest-Load Hours in Q1 2015**

	Median HHI	Max HHI	Median Share of Top <i>N</i> Participants				Median Number of Participants	Median Load (MW)
			<i>N</i> = 1	<i>N</i> = 4	<i>N</i> = 8	<i>N</i> = 16		
<b>Peak hour</b>	563	667	12%	37%	59%	80%	126	18,460
<b>Lowest-load hour</b>	674	804	15%	44%	63%	83%	124	13,662

- The systemwide *Residual Supply Index* (“RSI”) measures the percentage of demand in a given hour (in megawatt-hours) that can be met without any capacity from the largest supplier. The RSI also measures the number of hours in which one or more suppliers is pivotal, or can price above the competitive level, subject only to offer caps, mitigation measures, and the price elasticity of demand.<sup>19</sup> The system level analysis shows that there were no pivotal suppliers in any of the hours in the Reporting Period as can be seen in Figure below.

**Figure 2-11: Systemwide Residual Supply Index duration curve, all hours, Q1 2015.**



<sup>19</sup> When the RSI exceeds 100%, the system has sufficient capacity from other suppliers to meet demand without any capacity from the largest supplier. When the RSI is below 100%, a portion of the largest supplier’s capacity is required to meet market demand, and the supplier is pivotal. As RSIs rise, the ability of market participants to unilaterally set prices above competitive levels decreases. RSIs generally are lowest during periods of high demand, indicating a drop in the level of competition as the system approaches its capacity limit.

## Section 3

# Energy Market Offer Flexibility

### 3.1 Overview

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The ISO implemented Energy Market Offer Flexibility (“EMOF”) changes on December 3, 2014.<sup>20</sup> The offer flexibility introduced through EMOF improves a market participant’s ability to reflect in its energy market offer the cost of procuring fuel for each hour of the operating day and to update the cost in real time. Offers that more accurately reflect actual fuel prices improve the efficiency of the dispatch, improve the quality of energy market price signals, and reduce the risk to generators that may be capitalized into their offers.

The following aspects of EMOF were reviewed for this report:

- Generator offer block changes by hour
- The use of negative supply offers
- Negative real-time LMPs
- Self-scheduling and the use of economic minimum and maximum physical parameters, and
- Market power mitigation

In general, the improvements in offer flexibility are being utilized by participants and are working as intended under the market rules. The IMM will continue to monitor how EMOF changes are working and will include updates in upcoming reporting.

### 3.2 Generator Offer Block Changes by Hour

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For this first analysis, we reviewed how market participants revised generator financial parameters for startup fees, no-load fees, and energy offer block pricing.<sup>21</sup>

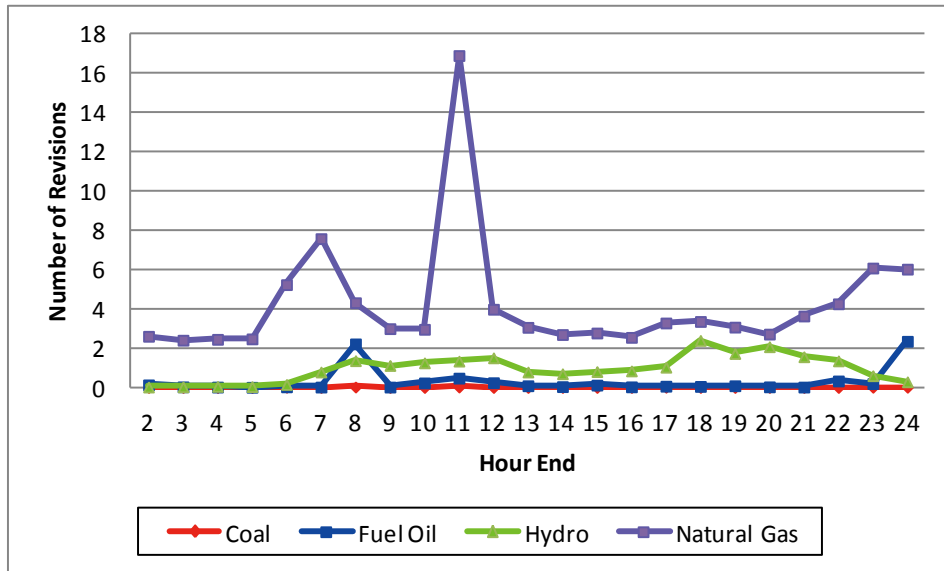
The graphs below show the prevalence of generators altering the price of the first block of their offer during the real-time and day-ahead energy markets. For the real-time energy market, Figure 3-1 shows the average number of these price changes by hour of the day and generator fuel type. Many generators update their offers at the beginning of the electric market day, 12 AM or HE01. The graphs exclude that updating activity. The graph shows that for hour ending 11 an average of 17 gas-fired generators changed the price of the first segment of the energy supply offer compared to an average of three revisions in HE10.

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<sup>20</sup> ISO New England Inc. and NEPOOL, *Energy Market Offer Flexibility Changes*, Docket No. ER13-1877-000, FERC filing, (July 1, 2013), [http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/jul/er13\\_1877\\_000\\_mkt\\_offer\\_flex\\_7\\_1\\_2013.pdf](http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2013/jul/er13_1877_000_mkt_offer_flex_7_1_2013.pdf). FERC, *Order Conditionally Accepting Tariff Revisions*, Docket No. ER13-1877-000 (October 3, 2013), [http://www.iso-ne.com/regulatory/ferc/orders/2013/oct/er13-1877-000\\_10-3-13\\_order\\_condition\\_accept\\_flex\\_rev.pdf](http://www.iso-ne.com/regulatory/ferc/orders/2013/oct/er13-1877-000_10-3-13_order_condition_accept_flex_rev.pdf).

<sup>21</sup> The IMM examined data for economically-offered generation (i.e., generation available for commitment and dispatch and not requesting a “self-schedule”). For the offer blocks, the pricing changes are shown only for the first offer block, to minimize the complexity of the review. Generators can submit up to 10 offer blocks. The pattern of updating offers over the market day is consistent across the financial parameters.

**Figure 3-1: Average number of offer block price revisions by fuel type and hour in the real-time energy market, Q1 2015 (HE02-24)**

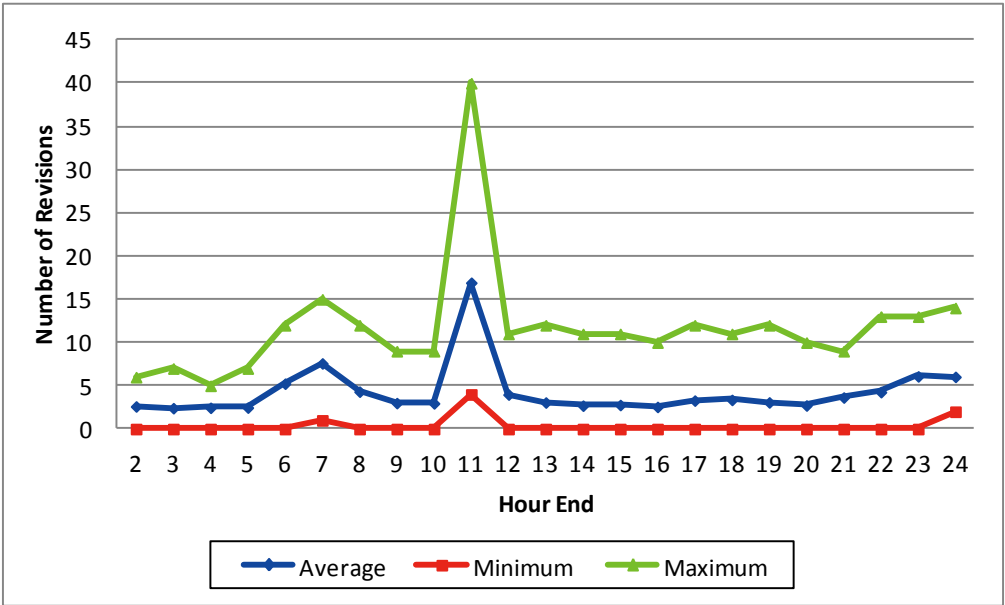


As expected, gas generators, which may experience significant price variation between “gas days” and within the electricity market operating day, alter their financial offer parameters more frequently on average than generators using other fuel types.<sup>22</sup> For non-gas-fired-generators, no more than two offers were being updated, on average, during the real-time energy market day. Figure 3-1 illustrates three noticeable updating periods per day for gas generators: just prior to the end of the gas day and before the morning generator ramping period (HE06 to HE08), at the beginning of the gas day (HE11), and at the beginning of the off-peak electricity market period (HE24).

Figure 3-2 below shows the offer block price revisions for gas generators and shows the average, minimum, and maximum number of offer price revisions by hour of the day for the Reporting Period. Except for the beginning of the gas day, the number of offers being revised was relatively modest. The maximum number of offer block prices revised during any hour was 40 offers in HE11. All other hours exhibit relatively small numbers of pricing revisions ranging from zero in most hours to no more than fifteen in HE07.

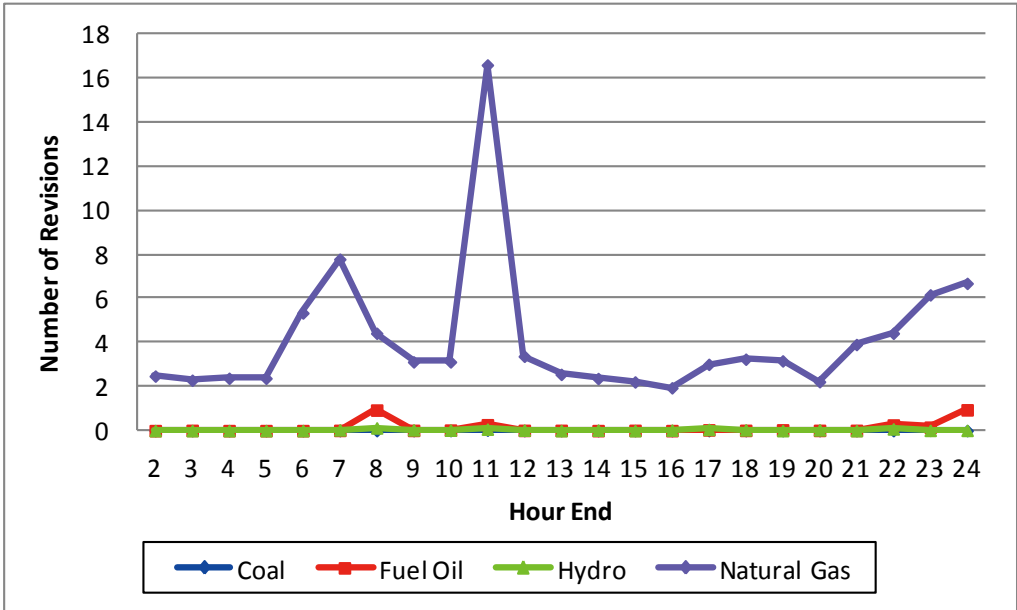
<sup>22</sup> The 24-hour “gas day” begins at 10 AM eastern time and ends the next day at 9:59 AM.

**Figure 3-2: Offer block revisions for natural gas generators by hour of day in the real-time energy market, Q1 2015 (HE02-24)**



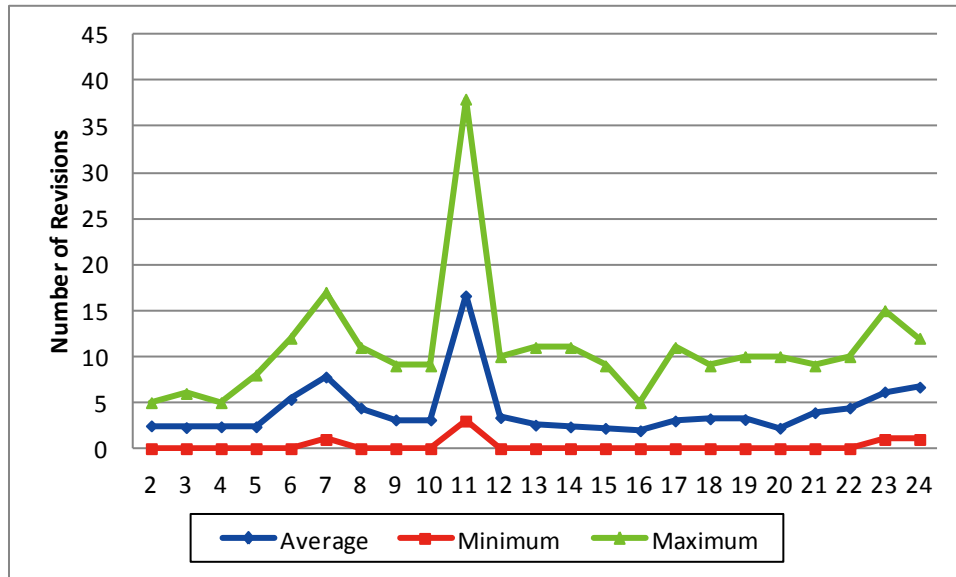
Changes in hourly offer prices in the Day-ahead market are highly consistent with patterns observed in the real-time market. Figure 3-3 shows average revisions by fuel type, again highlighting the higher average frequency of revisions for generators burning natural gas.

**Figure 3-3: Average number of offer block price revisions by fuel type and hour in the day-ahead energy market, Q1 2015 (HE02-24)**



Revisions of Day-ahead offer prices from generators burning natural gas exhibit approximately the same timing and magnitude as observed in the real-time market; see Figure 3-4.

**Figure 3-4: Offer block price changes for natural gas generators by hour of day in the day-ahead energy market, Q1 2015 (HE02-24)**



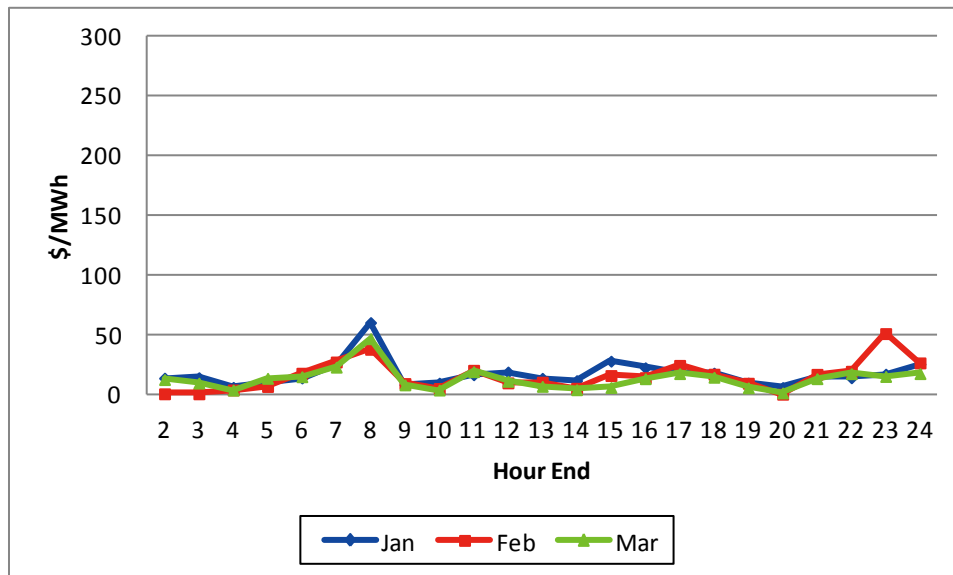
The magnitude of the absolute change in offer prices by generator for each hour of the day in the real-time market was also reviewed for generators that revised offers.<sup>23</sup> Figure 3-6 illustrates the offer price change for the first offer block by hour of the day and month in the Reporting Period.<sup>24</sup> For example, in February 2015, generator offers in hour 8, on average, differed by \$50/MWh from hour 7 offers for those generators that revised their offers.

The large absolute changes in offer prices for some hours are influenced by generators utilizing negative offers (changing from positive to negative offers) to adjust generation levels during certain parts of the day (e.g., the early morning commitment/ramp period). Except for HE07 and HE08 (the beginning of the morning generator ramp period) and HE23 (the final hour of the on-peak period), average absolute variation in offer pricing was relatively modest in most hours across the 3-month period.

<sup>23</sup> In this analysis, generators that did not revise their offers going from one hour to the next hour (that is, an offer price change of \$0/MWh) have been excluded from the calculation of averages.

<sup>24</sup> Certain outliers were removed from the data review as those values obscured the general market trend. The IMM has enquired about the basis for such outliers with individual participants.

**Figure 3-5: Average segment price revision for natural gas generators by month and hour in the real-time energy market, outlier offer removed from dataset, Q1 2015 (HE02-24)**



### 3.3 The use of Negative Supply Offers

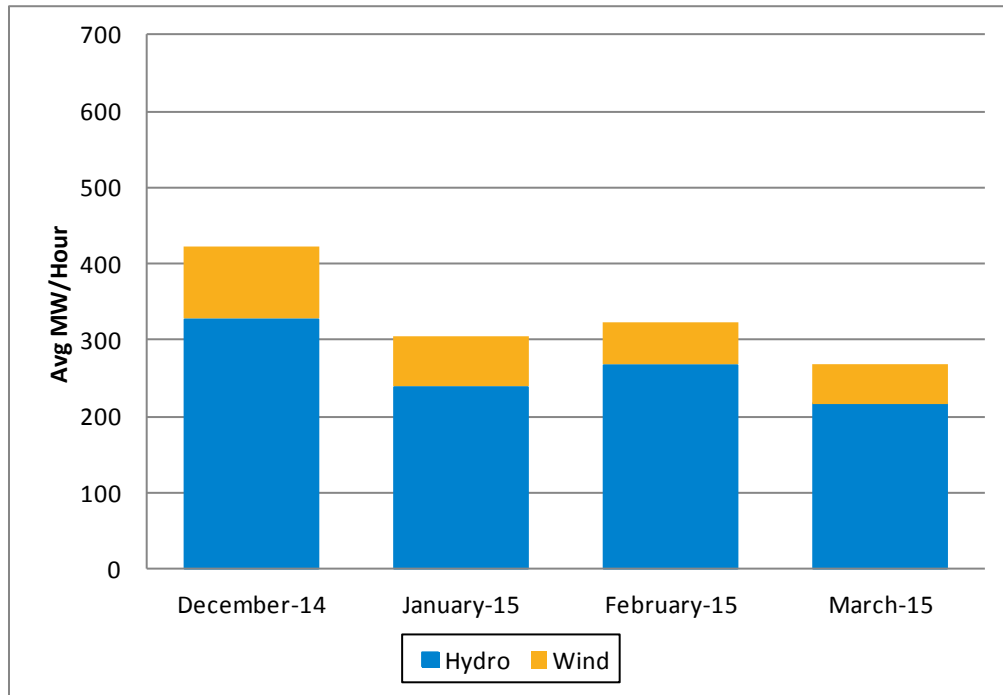
Under the EMOF rules participants were given the ability to price offer blocks below \$0/MWh (and down to as low as negative \$150/MWh) in the day-ahead and real-time energy markets. The negatively-priced offers allow generators to signal the energy market of their desire not be dispatched below a particular loading level, except when the energy market is experiencing significant excess on-line generating capacity and negative pricing occurs.<sup>25</sup>

When negative prices occur in the energy market, on-line generators are required to pay load for the energy they are generating. Typically, generators would be unwilling to remain on-line during periods with negative prices, unless those periods are of short duration or generators have limited control of output (e.g., intermittent generators), significant intertemporal constraints, high shut down or startup costs, or opportunity costs associated with taking the generator off-line.

The use of negative offers by generators from December 3, 2014 (the initiation of negative offers) to March 31, 2015 was reviewed. Figure 3-6 shows the frequency, in average MWs per hour, of negative offers by fuel type in the day-ahead energy market. Over this time period, some hydro and wind generators offered negative prices in the day-ahead market to ensure a desired level of dispatch unless the market price became sufficiently negative, when they were then willing to reduce output. The use of negative offer prices in the day-ahead market declined over this time period.

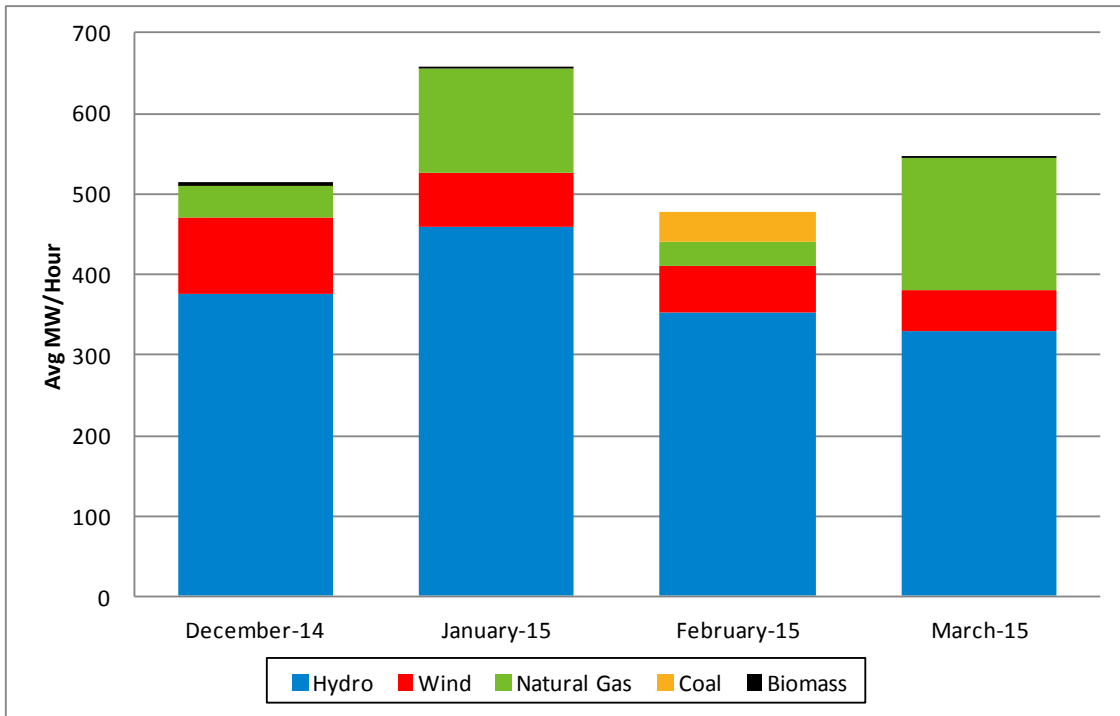
<sup>25</sup> Generators still have the option of self-scheduling generation, which allows generators to maintain a certain level of generation irrespective of market prices. The IMM's data and graphs exclude generator offer levels that have been self-scheduled. Generators may also utilize a limited energy generation (LEG) offer to limit the total amount of daily generation (MWh) available to the energy market during the market day as long as there is a physical limitation that restricts output. The IMM has not attempted to adjust the data to account for such daily total energy limitations, because of the complexities of trying to estimate whether the LEG limitation would bind (effectively reduce offered MWs) in an hour when the generator had a negative offer.

**Figure 3-6: Day-ahead negative offers by month and primary fuel type (average MW/hour)**



In the real-time energy market, negative offers have been used by generators with a variety of fuel types: wind, hydro, natural gas, biomass, and coal. See Figure 3-7. Hydro generators continue to offer the largest quantity of average MWs per hour of all the fuel types, with other fuel types exhibiting a relatively modest use of this pricing. Negative offers by non-intermittent generators can be used to shape the generator’s output over the real-time operating day, or to avoid de-commitment, when it is to the generator’s perceived advantage to stay on-line. On average, the amount of capacity offered in the real-time market at negative prices was equal to roughly 3% to 4% of load.

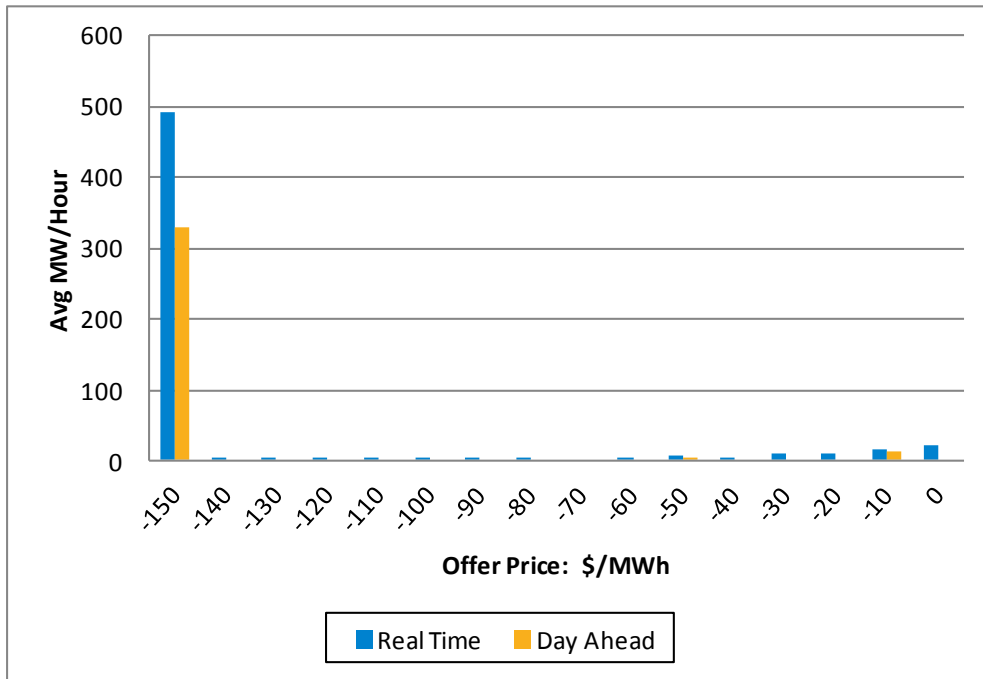
Figure 3-7: Real-time negative offers by month and primary fuel type (average MW/hour)



Lastly, Figure 3-8 shows that the vast majority of negative offers in the day-ahead and real-time energy markets have occurred at, or near, -\$150/MWh. This graph shows the average hourly quantity offered at negative prices, varying from -\$0.01/MWh to -\$150/MWh in \$10/MWh increments. For example, approximately 320 MWs per hour on average were offered in the day-ahead energy market at offer prices between -\$140/MWh and -\$150/MWh. Overall, while generators have utilized the enhanced offer capabilities provided by EMOF (i.e., hourly offer flexibility and negative offer pricing), only a relatively small amount of generating capacity has taken advantage of these capabilities.<sup>26</sup>

<sup>26</sup> This is especially true for negative offer pricing. When compared to generator self-scheduling behavior (which indicates a complete indifference to market pricing: i.e., generator is willing to stay on-line even when prices are below negative \$150/MWh), the capacity utilizing negative offer prices is quite small. See the section of this report describing generator self-scheduling behavior.

**Figure 3-8: Distribution of negative offers by offer pricing, December 2014-March 2015**



### 3.4 Negative Real-Time LMPs

Prior to the implementation of hourly markets, since participants could not offer into the market below \$0/MWh, the only way negative prices could occur was due to congestion, which occurred very infrequently.<sup>27</sup> The ability to submit negative hourly offers and the degree to which negative offers are utilized, will result in units with negative offers at the margin from time to time.

In the Reporting Period, pricing intervals with negative LMPs at the zonal level were observed. For all load zones, there were 1,278 5-minute intervals with negative LMPs, which was less than 1 percent of all possible pricing intervals (see Table 3-1). In addition, approximately 20% of the negative LMP values fell between -\$0.01 and -\$5.00/MWh.

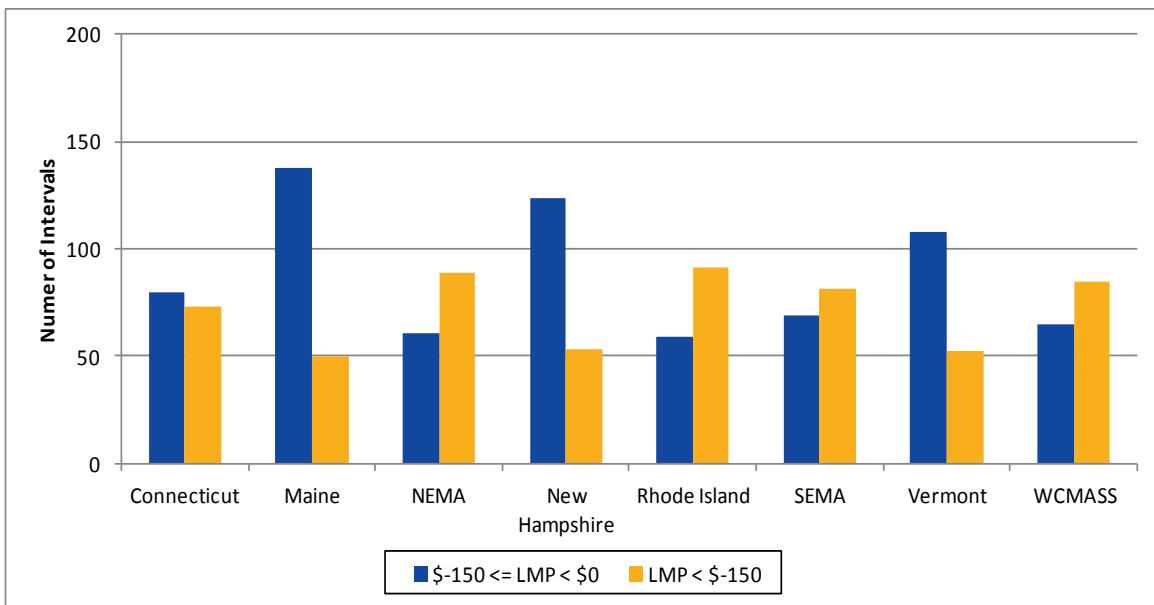
<sup>27</sup> Only five 5-minute intervals of negative LMPs were observed during the first quarter of 2014.

**Table 3-1: Price Distribution and Frequency of Negative LMPs by Load Zone, Q1 2015**

Load Zone	Frequency	Minimum LMP (\$/MWh)	Average LMP (\$/MWh)	Maximum LMP (\$/MWh)	Median LMP (\$/MWh)	Occurrence (%)
Connecticut	153	-\$663.57	-\$112.16	-\$0.01	-\$149.90	0.59%
Maine	188	-\$158.38	-\$100.91	-\$0.01	-\$143.03	0.73%
NEMA	150	-\$168.47	-\$108.80	-\$0.01	-\$151.52	0.58%
New Hampshire	177	-\$164.04	-\$97.41	-\$0.01	-\$147.25	0.68%
Rhode Island	150	-\$169.42	-\$109.08	-\$0.01	-\$151.35	0.58%
SEMA	150	-\$169.44	-\$108.83	-\$0.01	-\$151.61	0.58%
Vermont	160	-\$281.94	-\$102.12	-\$0.01	-\$147.62	0.62%
WCMASS	150	-\$167.34	-\$108.22	-\$0.01	-\$150.61	0.58%
<b>All Zones</b>	<b>1278</b>	<b>-\$663.57</b>	<b>-\$105.60</b>	<b>-\$0.01</b>	<b>-\$148.08</b>	<b>0.62%</b>

The negative LMPs were the result of conditions of relative over-generation in real-time that were resolved by dispatching resources that had submitted offers with negative prices. Figure 3-9 shows the number of 5-minute pricing intervals, by load zone, that had negative LMPs, a total of 1,278 intervals across all load zones. The stacked bars are divided into two segments: LMPs between \$0/MWh and -\$150/MWh and LMPs that are less than -\$150/MWh. Since resources have an offer floor of -\$150/MWh, prices that decreased below -\$150/MWh were the result of losses and congestion contributing to the negative prices. The load zone with the greatest number of negative LMPs was Maine, which is predominantly an exporter of energy to the rest of New England and has a large supply of hydro and renewable resources that offer in below \$0/MWh.

**Figure 3-9: Number of 5-minute Real-Time pricing intervals with negative LMPs by load zone, Q1 2015.**



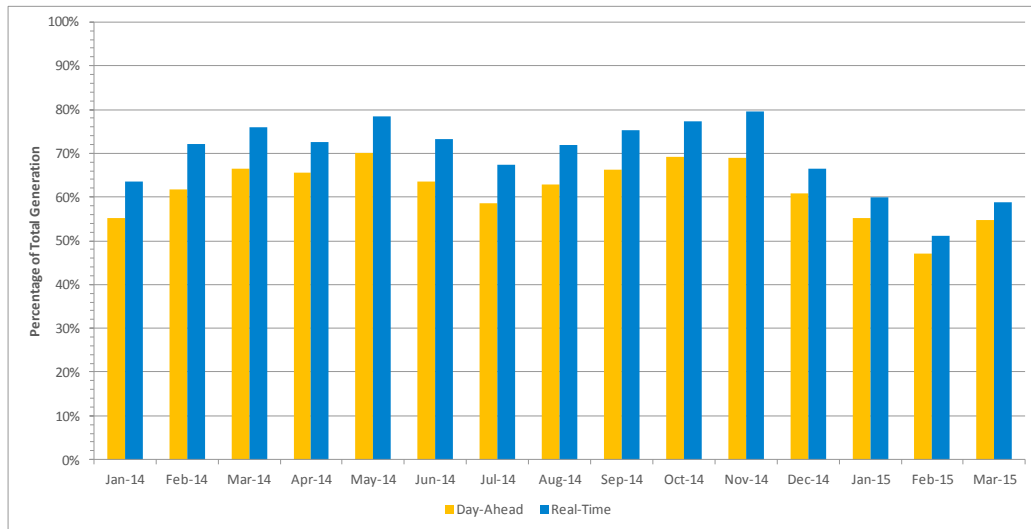
### 3.5 Self-scheduling and the use of Economic Minimum and Maximum Physical Parameters

Changes to the self-scheduling practices of generators were to be expected with the implementation of the Energy Market Offer Flexibility (EMOF) rules in early December 2014. First, with the ability to profile and update offers on an hourly basis, as opposed to a single set of offer prices for an entire operating day, generators with incremental heat rates can no longer leverage Economic Minimum and Maximum parameters of their resources to manage economic output levels.<sup>28</sup> Second, the reduction of the offer floor price from \$0 to negative \$150/MWh allows generators to signal desired levels of output over a greater range of prices and to use price to limit downside risk of potential negative prices rather than self-scheduling and assuming a price-taker role in the energy market.

The amount of self-scheduling as a percentage of total generation has decreased with EMOF implementation. In Figure 3-10, self-scheduled energy as a percentage of total generation is shown by month for both the day-ahead and real-time markets. The reason for the decrease is that under EMOF, dispatchable generators are expected to self-schedule at their physical Economic Minimum output level. For a dispatchable generator to obtain a dispatch point above its Economic Minimum value, it must use its hourly energy offer to reflect the price at which it is willing to operate at various output levels. Prior to EMOF, generators profiled their Economic Minimum value across hours to achieve their desired output levels.

<sup>28</sup> Definition of *Economic Minimum* and *Economic Maximum* can be found in Section 1 – *General Terms and Conditions* of the ISO New England Inc. Transmission, Markets and Services Tariff.

**Figure 3-10: Day-Ahead and Real-Time self-scheduled energy as a percentage of total generation, January 2014 - March 2015**

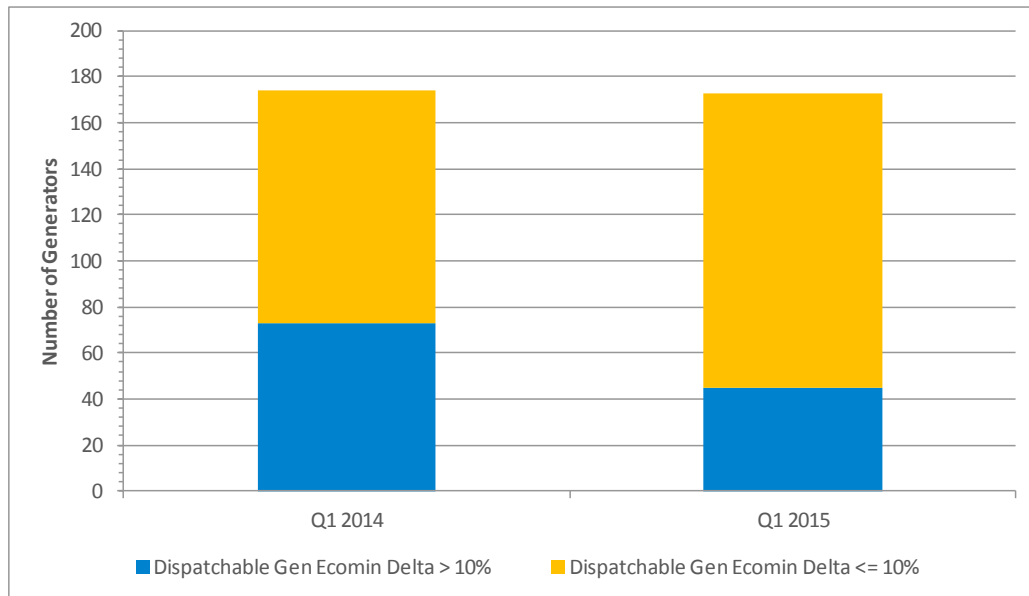


*Real-Time Self-Schedules.* The number and behavior of generators using the self-schedule option in the Real-Time market was examined. In the first quarter of 2015, it was observed that 277 generators self-scheduled in the Real-Time market for at least one hour. This number is down slightly from the 299 generators that used the option in the first quarter of 2014.

In addition, the number of generators adjusting their Economic Minimum values to achieve their desired level of output has also decreased. In the first quarter of 2015, only 45 of the 173 generators that self-scheduled during at least one hour with a dispatchable range adjusted their Economic Minimum values by more than 10%.<sup>29</sup> In the first quarter of 2014, 73 of the 174 generators that self-scheduled during at least one hour with a dispatchable range adjusted their Economic Minimum values by more than 10% (see Figure 3-11).

<sup>29</sup> A 10% threshold was chosen to eliminate the “noise” of small changes in hourly Economic Minimum values.

**Figure 3-11: Number of Real-Time self-scheduled dispatchable generators by change in Economic Minimum, Q1 2014 vs. Q1 2015**



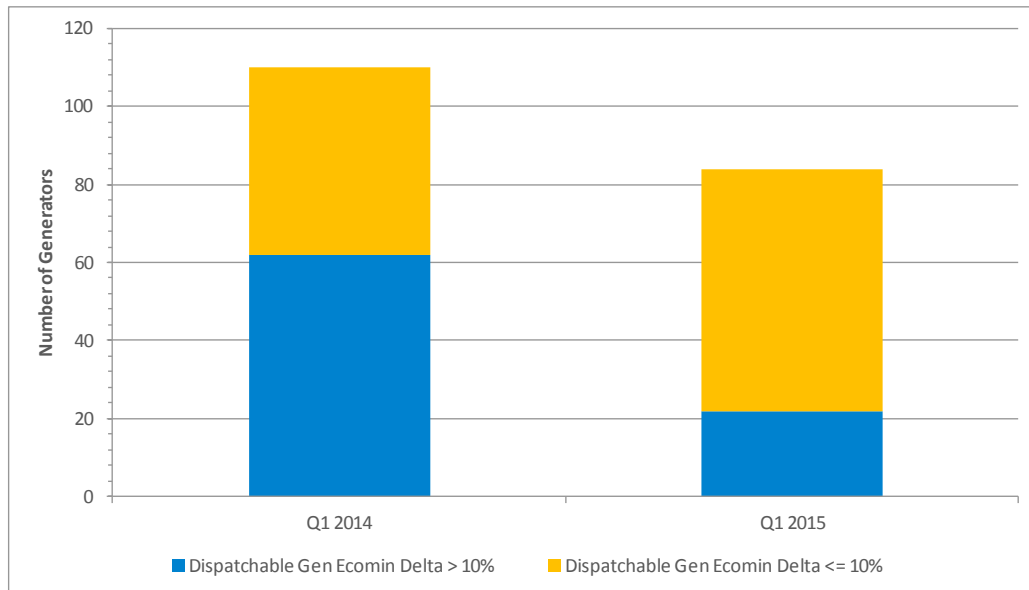
The decrease in the number of generators changing their Economic Minimum is expected since with the implementation of EMOF generators with incremental heat rates can only use their hourly energy offers to achieve an economic level of output above Economic Minimum in both the day-ahead and real-time market. Through the hourly offer the generator communicates the minimum price required to cover its variable production and opportunity costs at various output levels and market and system conditions determine the level of economic output. . Economic Minimum values should only be adjusted to reflect a change in a generator’s physical capability or for facility and equipment testing or auditing.<sup>30</sup>

*Day-Ahead self-schedules.* Additionally, the number and behavior of generators using the self-schedule option in the Day-Ahead market was examined. In the first quarter of 2015, it was observed that 143 generators self-scheduled in the Day-Ahead market for at least one hour. This number is down from the 178 generators that used the option in the first quarter of 2014.

The number of generators adjusting their Economic Minimum values to achieve their desired level of output has also decreased. In the first quarter of 2015, 22 of the 84 generators that self-scheduled during at least one hour with a dispatchable range adjusted their Economic Minimums by more than 10%. In the first quarter of 2014, 62 of the 110 generators that self-scheduled during at least one hour with a dispatchable range adjusted their Economic Minimums by more than 10% (see Figure 3-12).

<sup>30</sup> The exception is that non-dispatchable generators can also adjust Economic Minimum to reflect fuel limitations, environmental regulations and licensing limits.

**Figure 3-12: Number of Day-Ahead self-scheduled dispatchable generators by change in Economic Minimum, Q1 2014 vs. Q1 2015**



*Use of Economic Minimum and Maximum Parameters for resources not self scheduling.* Changes in the economic minimum and economic maximum parameters of generator offers in the Day-Ahead and Real-Time Markets between Q1 2014 and Q1 2015 were analyzed to determine if units were changing these parameters to achieve desired levels of output instead of using price when the unit was offered economically into the energy markets. The IMM found that, on average generators that have not self-scheduled change their economic minimum value less than 2% of the time and the majority of those changes are less than 5% compared to the previous hour; this was the case for both Q1 2014 and Q1 2015. The IMM also observed similar patterns of behavior for the Real-Time economic max maximum parameter as well as changes made to these parameters in the Day-Ahead market.

*Conclusion:* Overall, while the numbers of generators changing their Economic Minimum value has decreased since the implementation of EMOF as expected, the IMM will be monitoring offer behavior in this regard and making enquiries where appropriate to satisfy itself that such changes are the result of a physical limitation on the generator.

### 3.6 Market Power Mitigation

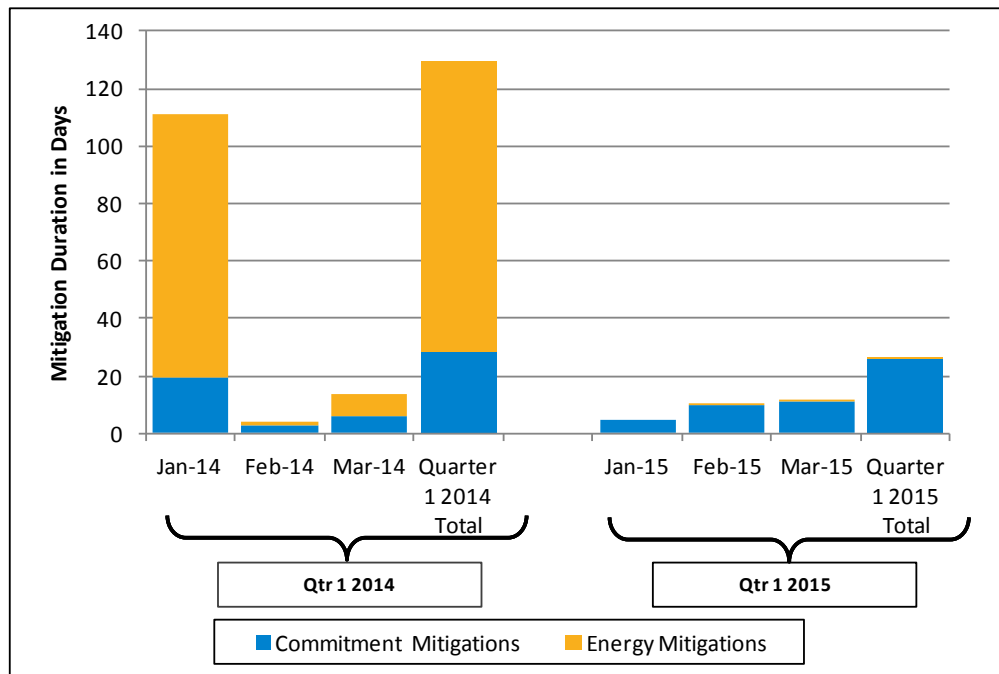
In order to complement the ability to structure and change certain supply offer parameters on an hourly basis, a suite of changes to the IMM’s market power mitigation rules were implemented.<sup>31</sup> With the revisions to the duration of mitigation rules one would expect a higher number of mitigations of *shorter duration*. For example, prior to EMOF if a resource was committed for 4 hours

<sup>31</sup> These changes included: Developing hourly reference levels rather than reference levels that are fixed for an operating day; Modifying commitment mitigation conduct tests so that they account for the low load cost over the commitment period; Modifying the duration of mitigation such that commitment mitigation is in effect for the duration of the commitment period and energy mitigation is in effect until structural market power or market impact are no longer detected; Introduction of limits based on fuel prices, to the amount that start-up fees and no-load fees may be increased in real time; Implementation of mechanisms to permit Market Participants to enter fuel price adjustments to resource reference levels to reflect hourly changes in fuel costs; and Elimination of the requirement that Market Participants with dual fuel resources submit offers based on the resource’s least cost fuel under certain conditions.

and mitigated, it would remain mitigated for the remainder of the day. If there was a further reliability commitment for two hours later that day, the resource supply offer would have already mitigated. This would count as one mitigation event with a duration of 14 hours, whereas under EMOF under the same scenario there would result in two mitigation events totaling 6 hours, the first for 4 hours and the second for 2 hours.

Figure 3-13 below shows the sum of the duration (in days) of all mitigations for each month and the total for the first quarter of 2014 and 2015. To put the scale into perspective, approximately 330 generation resources are subject to mitigation. If every resource was mitigated every day of a 31 day month there would be 10,230 “mitigation” days in that month. This is the maximum number of possible mitigation days. Therefore, in January 2014, the highest duration of mitigations to date, generation was mitigated less than 1.3% of the time.

**Figure 3-13: Commitment and energy mitigations in Quarter 1 2014 and 2015 in days**



Variation in mitigations over time will depend on system and market conditions and generator offer behavior relative to reference levels. In January 2014, import constraints were prevalent and many of the mitigations occurred on three days, January 7, January 23, and January 28. High gas prices meant that the constrained energy mitigation threshold of \$25/MWh was relatively tight in terms of the percentage of the generator offer for some units.<sup>32</sup> Also, many generators that tend to be extra marginal and that violated the mitigation thresholds were brought on-line to address those constraints in January 2014.

System and market conditions were different in January 2015. Compared to January 2014, in January 2015 total Net Commitment Period Compensation costs were down 87% and natural gas

<sup>32</sup> The constrained area energy threshold is the minimum of the reference level times 1.5 and the reference level plus \$25/MWh. For example, assuming an average heat rate of 10,000 British thermal units/kilowatt-hour (Btu/kWh) and an average January 2014 gas price of almost \$24/million Btu (MMBtu), the effective threshold of \$25/MWh represents a conduct test threshold of just over 10% of costs.

prices were 61% lower. Overall, the reduction in energy mitigations observed in the Reporting Period is consistent with system and market conditions. The new mitigation rules under EMOF have had no discernible impact on number of energy market mitigations.

While the IMM has not observed a significant change in the total duration of commitment mitigations in the Reporting Period, there has been an increase in the frequency of commitment mitigations, particularly in mitigations of one-hour durations with units remaining on-line beyond their initial commitment and during ramp-down periods. Many of mitigation occur when an operator takes no action to shut down a unit beyond its initial commitment.

Table 3-2 below shows the number of commitment mitigations in unit days for quarter 1 of 2014 and 2015.<sup>33</sup>

**Table 3-2: Commitment mitigations in Quarter 1 2014 and 2015 in Unit Days**

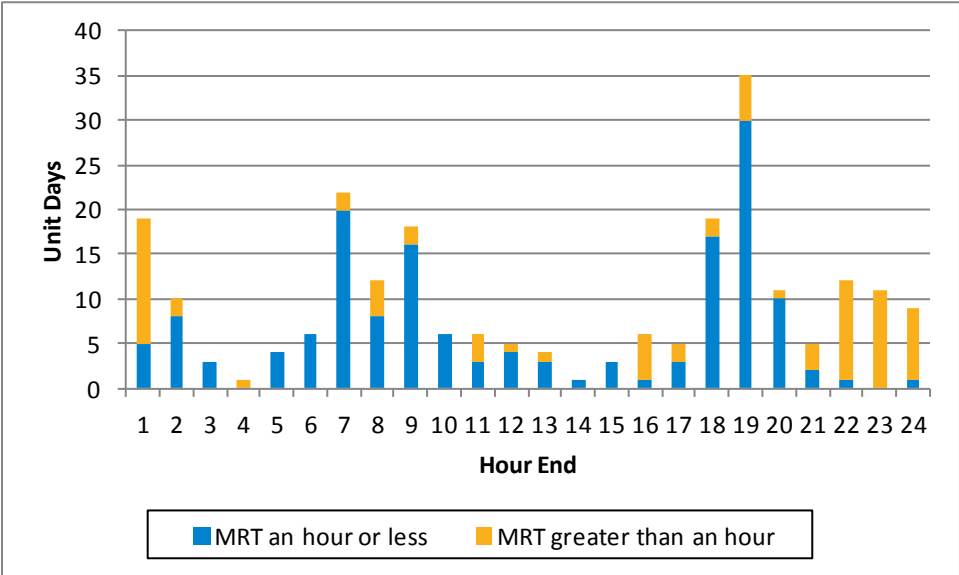
Month	Quarter 1 2014	Quarter 1 2015
January	34	59
February	3	97
March	7	77
<b>Total</b>	<b>44</b>	<b>233</b>

Commitment mitigations were assessed by minimum run time (MRT), with MRT of an hour or less as a proxy for fast start resources and units having a MRT of more than an hour generally representing non fast-start resources. Of the commitment mitigations 155 (67%) were for units that had MRTs of an hour or less. Figure 3-14 below shows that units with a MRT greater than an hour being mitigated for an hour (or more) beyond their original commitment time in the late peak and early morning hours (through HE01). Figure 3-14 also shows a greater concentration of units with a MRT of an hour or less being mitigated in HE07-09 and HE18-20, indicating that these types of units were being kept on over the daily peak periods in the winter. The mitigated resources are violating the reliability conduct test threshold of 10% over the low load cost reference level.

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<sup>33</sup> "Unit Days" counts resources that are mitigated more than once in a given operating day as one mitigation.

Figure 3-14: Commitment mitigations by minimum run time, Q1 2015



## Section 4

### Review of the Ninth Forward Capacity Auction

This section presents a review of the ninth Forward Capacity Auction (FCA), which covers the commitment period from June 1, 2018 to May 31, 2019.

The FCA modeled four capacity zones in the ninth FCA: Southeastern Massachusetts/Rhode Island (SEMA-RI), Connecticut, Northeastern Massachusetts/Boston (NEMA-Boston) and Rest-of-Pool. For the first time, SEMA-RI was modeled as a single capacity zone and was determined to be import constrained. Also for the first time, the system-wide sloped demand curve was applied to determine the price at which system-wide aggregate supply intersected the system-wide quantity demanded.

The IMM concluded that the outcome of the auction system-wide was competitive, and no anti-competitive behavior was evident. However, the SEMA-RI capacity zone lacked sufficient capacity to meet the zonal requirement and was therefore not competitive.

Conditions existed which caused the capacity zones and external interfaces to close at different rounds and prices:

- The auction did not run in the SEMA-RI capacity zone, as conditions were met to trigger inadequate supply.<sup>34</sup> As a result, the payment rate for existing resources located in SEMA-RI was set to the Net Cost of New Entry (or net CONE) of \$11.080/kW-month, and the payment rate for new resources was set to the FCA 9 starting price (\$17.728/kW-month).
- The rest of the system (with the exception of New York AC Ties and New Brunswick Interfaces) closed in round three with a payment rate of \$9.551/kW-month.
- New York AC Ties closed in round four with a payment rate of \$7.967/kW-month.
- New Brunswick closed in round five with a payment rate of \$3.940/kW-month, which concluded the auction.

#### 4.1 Sloped Demand Curve

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In FCA 9, the demand for system installed capacity was defined by a downward sloping demand curve for the first time. The purpose of a system sloped demand curve is to improve price formation in the capacity market – specifically, to reduce price volatility and establish efficient price signals to maintain the region’s reliability criteria in the long run.

The system-wide sloped demand curve was applied to determine the price at which system-wide aggregate supply intersected the system-wide quantity demanded. The system-wide sloped demand curve replaced the Net Installed Capacity Requirement (NICR) as the determinant of system-wide capacity demand for purposes of clearing the auction.

The system-wide sloped demand curve's shape is defined by pertinent financial and reliability parameters. At prices below the FCA Starting Price of \$17.728/kW-month, the system-wide quantity demanded increases linearly as the price decreases. The demand curve is designed to

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<sup>34</sup> See Market Rule 1, III.13.2.8.

procure over time capacity sufficient to meet the resource adequacy requirement for the New England Control Area, the NICR.

The demand curve is based, in part, on an administrative Net CONE value of \$11.08/kW-month, which is the estimated capacity market revenue a combined cycle unit would need in its first year of operation. The demand curve is designed to ensure that prospective resource developers are able to recover just enough money in the New England markets to make it financially viable to build a power plant in New England when the region is short of its resource target.

## 4.2 Requirements and Resource Qualification

Table 4-1 shows the system and local capacity requirements for FCA 9. About 34,000 MW of capacity was needed to ensure systemwide resource adequacy. The Connecticut (CT), SEMA-RI, and NEMA-Boston zones are import-constrained zones. Local sourcing requirements, approximately 7,300, 7,500, and 3,600 MW respectively, were included for each region in the auction.

**Table 4-1: Capacity Requirements or Limits for FCA 9 (MW)**

Auction	Net Installed Capacity Requirement (NICR)	Local Sourcing Requirement (LSR)		
	System-wide	CT	SEMA-RI	NEMA-Boston
FCA 9	34,189	7,331	7,479	3,572

Table 4-2 summarizes the existing and new qualified capacity for FCA 9 by zone and compares that capacity to the relevant capacity requirement (i.e., NICR and LSR). Systemwide, existing capacity (32,101 MW) was approximately 2,100 MW less than the NICR of 34,189 MW. As a result, the IMM determined that all participants with existing resources were pivotal suppliers for the purpose of the application of de-list bid mitigation. In the import-constrained areas, Connecticut and NEMA-Boston were able to satisfy its local capacity requirement with existing capacity. SEMA-RI lacked sufficient capacity to satisfy the local capacity requirement.

**Table 4-2: Qualified Capacity Compared to Requirement or Limit, FCA 9 (MW)**

Zone	Existing	New	Total	Capacity Requirement or Limit
Connecticut	8,918	1,445	10,364	7,331
NEMA-Boston	3,833	362	4,195	3,572
SEMA-RI	6,888	353	7,241	7,479
Rest-of-Pool	12,461	3,271	15,733	n/a
<b>Total</b>	<b>32,101</b>	<b>5,432</b>	<b>37,533</b>	<b>34,189</b>

Table 4-3 shows the breakdown of qualified capacity by resource type for each zone. It is useful to note that, consistent with the ISO-NE Tariff rules, import capacity qualifies as new capacity in each

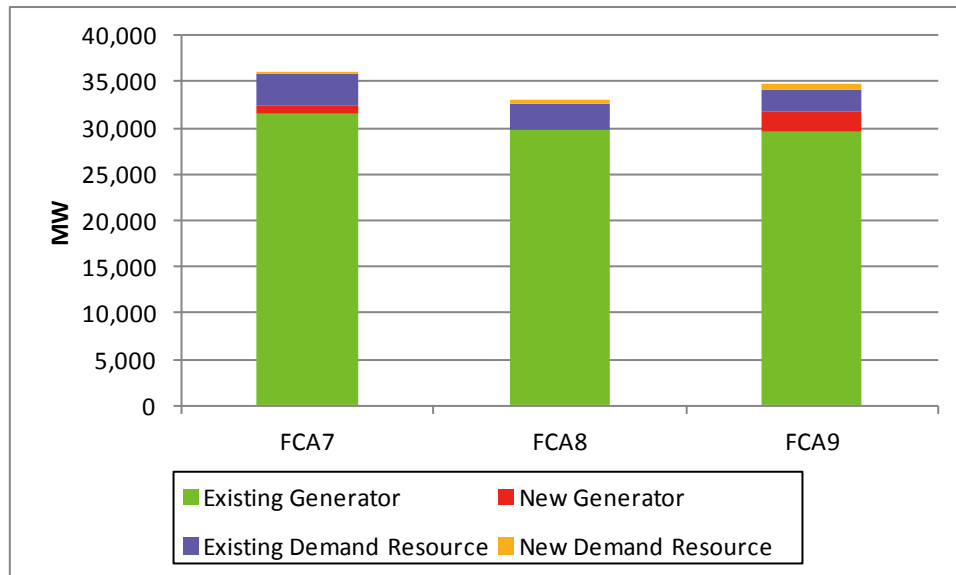
auction. Therefore, import capacity receives an annual, rather than long-term, obligation to supply capacity to the New England market if it clears.

**Table 4-3: Qualified Capacity by Resource Type and Qualification Status, FCA 9 (MW)**

Zone	Existing			Existing Total	New			New Total	Total
	Demand	Generator	Import		Demand	Generator	Import		
Connecticut	486	8,432	0	8,918	113	1,332	0	1,445	10,364
NEMA-Boston	532	3,301	0	3,833	166	196	0	362	4,195
SEMA-RI	475	6,413	0	6,888	139	214	0	353	7,241
Rest-of-Pool	945	11,428	89	12,461	199	350	2,722	3,271	15,733
<b>Total</b>	<b>2,438</b>	<b>29,574</b>	<b>89</b>	<b>32,101</b>	<b>618</b>	<b>2,092</b>	<b>2,722</b>	<b>5,432</b>	<b>37,533</b>

Total qualified capacity for Demand and Generators increased in FCA 9 when compared to FCA 8 by 5%. Even though additions to new capacity were small for generator resources in the Rest of Pool, SEMA-RI, and NEMA-Boston in FCA 9, total additions to new capacity for Demand and Generators increased by 539% when compared to FCA 8, and 139% when compared to FCA 7, as shown in Figure 4-1.

**Figure 4-1: New and Existing Qualified Capacity for Demand Resources and Generators, FCA 7, FCA 8, and FCA 9**



### 4.3 Auction Results

Table 4-4 below summarizes the auction results by round.

**Table 4-4: Results by Auction Round, FCA 9**

Auction Rounds	Systemwide (Includes NEMA and CT)	SEMA-RI	External Interface NY AC Ties	External Interface New Brunswick
<b>Round 1 Pricing</b>	\$17.728-\$14.00	Inadequate Supply	\$17.728- \$14.00	\$17.728-\$14.00
<b>Round 1 Capacity Excess</b>	1,907		1,148	213
<b>Round 2 Pricing</b>	\$14.000- \$11.000		\$14.000- \$11.000	\$14.000-\$11.000
<b>Round 2 Capacity Excess</b>	1,193		450	213
<b>Round 3 Pricing</b>	\$11.000-\$8.000		\$11.000- \$8.000	\$11.000-\$8.000
<b>Round 3 Capacity Excess</b>	0		100	213
<b>Round 4 Pricing</b>			\$8.000- \$3.940	\$8.000-\$3.940
<b>Round 4 Capacity Excess</b>			0	36
<b>Round 5 Pricing</b>				\$3.940-\$1.970
<b>Round 5 Capacity Excess</b>				0
<b>Capacity Clearing Price – New</b>	<b>\$9.551</b>	<b>\$17.728</b>	<b>\$7.967</b>	<b>\$3.94</b>
<b>Capacity Clearing Price - Existing</b>	<b>\$9.551</b>	<b>\$11.08</b>	<b>\$7.967</b>	<b>\$3.94</b>

*Systemwide.* The auction started with a price of \$17.728/kW-month. The auction ended in the third round when it bound system-wide when a new capacity offer was withdrawn. This resulted in aggregate supply falling short of demand, after accounting for the 238 MW capacity shortfall in the SEMA-RI Capacity Zone. As a result, Resources in NEMA-Boston, Connecticut and Rest-of-Pool Capacity Zones will be paid the Capacity Clearing Price set to the system-wide sloped demand curve, which was \$9.551/kW-month.

*SEMA-RI.* In the SEMA-RI Capacity Zone, there were inadequate resources to meet the zone's Local Sourcing Requirement, and the auction did not run. As a result, the Inadequate Supply administrative pricing rules were triggered. Under these rules, the 353 MW of new capacity in the zone will receive the auction starting price of \$17.728/kW-month, while 6,632 MW of existing resources in the zone will receive \$11.08/kW-month. 256 MW of existing self-supply resources will not receive payments through the Forward Capacity Market.

The Local Sourcing Requirement in SEMA-RI was 7,479 MW. There were 6,888 MW of existing capacity offers in the SEMA/RI Capacity Zone. The amount of New Capacity Required was 591 MW. Since the 353 MW of qualified new capacity in SEMA-RI was less than the New Capacity Required, the administrative pricing provisions of Inadequate Supply were triggered.

The amount of capacity procured in the SEMA-RI Capacity Zone was 238 MWs less than the Capacity Zone's Local Sourcing Requirement. The ISO will seek to procure additional resources to make up for this shortfall in the upcoming reconfiguration auctions for the 2018-2019 Capacity Commitment Period.

*New Brunswick and AC Ties.* The auction continued for one additional round for New York AC Ties imports, closing at \$7.967/kW-month and two additional rounds for New Brunswick imports,

closing at \$3.94/kW-month. The Capacity Clearing Price for the remaining external interfaces was \$9.551/kW-month.

The New Brunswick and New York AC Ties external interfaces had greater amounts of capacity offered than the capacity transfer limits for the interfaces at the Rest-of-Pool Capacity Clearing Price of \$9.551/kW-month. Accordingly, the New Brunswick and New York external interfaces were treated in the auction as if they comprised separately modeled export-constrained capacity zones. Therefore, additional bidding was required to determine the Capacity Clearing Price for each of those external interfaces.

*De-List bids.* For FCA 9, 118 delist bids from existing capacity resources were entered in the auction. The ISO accepted 12 these bids for a total of 194 MW. All of the delist bids were for a single year, allowing these resources to retain the option of re-entering the capacity market during FCA 10. See Table 4-5.

**Table 4-5: Delisted Capacity by Zone and Resource Type, FCA 9 (MW)**

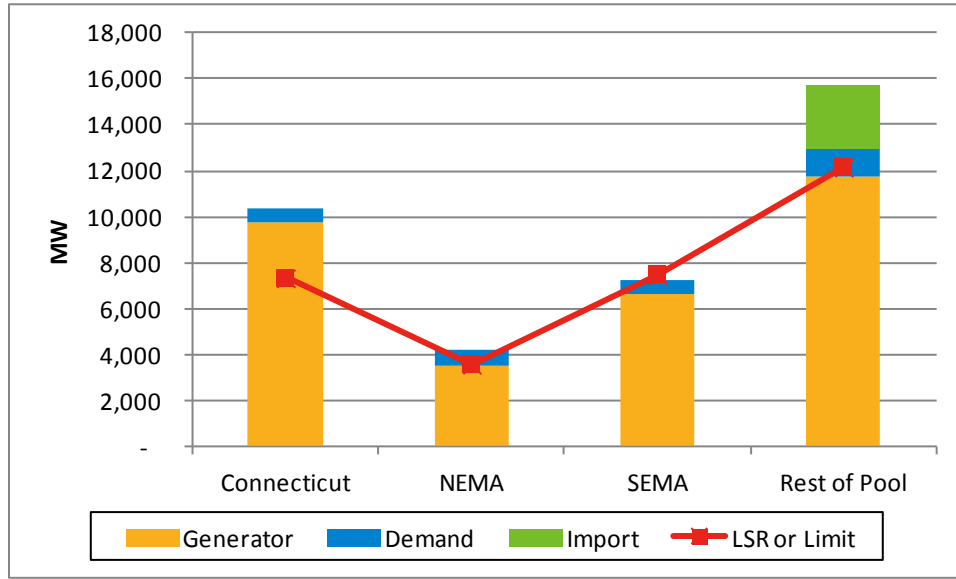
Zone	Demand	Generator	Total
Connecticut	-	17	17
NEMA-Boston	2	-	2
SEMA-RI	-	-	-
Rest-of-Pool	-	175	175
<b>Total</b>	<b>2</b>	<b>192</b>	<b>194</b>

#### 4.4 Cleared Capacity and Competitiveness of the Auction

Figure 4-2 below summarizes the cleared capacity (MW) from the auction, by capacity zone and resource type. Generators represented approximately 84% of cleared capacity, while demand and import resources represented 8% and 7%, respectively.<sup>35</sup> These results by resource type are comparable to prior auctions.

<sup>35</sup> The capacity requirement and excess capacity values are implied values for Rest-of-Pool, as those values are not explicitly modeled for the auction. The requirement for Rest-of-Pool is implied by the NICR less the zonal requirements and the excess capacity in NEMA-Boston and Connecticut.

**Figure 4-2: Cleared Capacity compared to Local Requirement or Limit, FCA 9**



*Competitiveness.* The outcome of the ninth FCA system-wide was the result of a competitive auction. However, there was insufficient capacity to meet the zonal requirement in the SEMA-RI zone. As a result of the capacity shortage, there could not be sufficient competition in this zone. The combination of offer mitigation and administrative pricing rules served to protect the auction from uncompetitive outcomes in this zone through the exercise of market power. Systemwide, there were insufficient existing resources to meet the Installed Capacity Requirement. As a result, the IMM determined that all participants with existing resources were pivotal suppliers. The IMM reviewed the cost basis of all submitted de-list bids and imposed mitigation, where necessary, on submitted de-list bids. Under the Tariff, new resources, with the exception of New Import Capacity Resources associated with pivotal suppliers, can leave the auction at any price at or above their New Resource Offer Floor Price. However, sufficient new resources remained in the auction long enough such that, with the IMM mitigation of existing resources and New Import Capacity Resources associated with pivotal suppliers, the outcome of the auction system-wide was competitive, and no anti-competitive behavior was evident.

**EXECUTIVE SUMMARY**  
**Status Report of Current Regulatory and Legal Proceedings**  
**as of August 5, 2015**

The following activity, as more fully described in the attached litigation report, has occurred since the report dated June 24, 2015 was circulated. New matters/proceedings since the last Report are preceded by an asterisk '\*'. Page numbers precede the matter description.

**I. Complaints**

1	NRG Canal 2 2015/16 ARA3 Complaint/Waiver Request (EL15-57)	Jul 16	FERC denies complaint/waiver request
4	Base ROE Complaints (2012 & 2014) Consolidated (EL14-86 & EL13-33)	Jun 25 Jun 25-Jul 2 Jul 13 Jul 15 Jul 23	Judge Sterner adopts unopposed motion for protective order Hearings held Parties submit joint transcript corrections and final index of exhibits Judge Sterner issues order adopting transcript corrections TOs file motion to lodge portion of testimony filed in Southwestern Public Service Co. ROE proceeding
5	206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices to be Adopted in Docket RM14-2 (EL14-23)	Jul 23	ISO files response explaining why changes to the ISO Tariff in response to the FERC's rule-making are not necessary

**II. Rate, ICR, FCA, Cost Recovery Filings**

6	FCA9 Results Filing (ER15-1137)	Jul 20	UWUA requests rehearing of <i>FCA9 Results Order</i>
6	Opinion 531-A Compliance Filing: TOs (ER15-414)	Jul 8	FERC accepts amended compliance filing, effective Oct 16, 2014
7	FCA1 Results Remand Proceeding (ER08-633)	July 15-17	ISO submits initial brief; initial briefs also submitted by Bridgeport Energy, Dominion, PSEG; reply briefs due Aug 17
* 7	2015/16 Power Year Transmission Rate Filing (ER09-1532; RT04-2)	Jul 31	PTO AC submits informational filing identifying adjustments to regional transmission service charges for the Jun 1, 2015 to May 31, 2016 period; this filing will not be noticed for public comment

**III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests**

* 8	CSO Terminations: Enerwise Global Technologies (ER15-2232)	Jul 21 Jul 27	ISO files to terminate Enerwise CSOs for Resource #s 16700, 37922 NEPOOL intervenes
* 9	CSO Termination: Hampshire Council of Gov'ts (ER15-2229)	Jul 21 Jul 27	ISO files to terminate CSO for Resource # 38110 NEPOOL intervenes
* 9	Jump Ball Filing: Winter Reliability Program (ER15-2208)	Jul 15 Jul 17- Aug 5  Aug 4-5	NEPOOL and ISO submit jump ball filing; comment date Aug 5 Brookfield, ConEd, Calpine, CT OCC, Emera, Exelon, Eversource, GDF Suez Energy North America, Noble Americas, NRG, UI, VT DPS intervene NESCOE, CT PURA, TransCanada support NEPOOL Proposal; Essential Power supports NEPOOL Proposal in part; Energy/NextEra/Dominion support ISO Proposal; Dynegy/Brayton Point support ISO Proposal in part; NEPGA/EPGA and PSEG protest both Proposals
10	CSO Terminations: Enerwise Global Technologies (ER15-1944)	Jun 29 July 16	NEPOOL intervenes FERC accepts termination

10	Waiver Request: FCM Interconnection Deposit Qualification Deadline (Bellingham) (ER15-1934)	Jun 29-Jul 2 Jul 1 Jul 16	NRG, NESCOE intervene ISO opposes waiver request NEA answers ISO's Jul 1 answer
10	CSO Terminations: Direct Energy Business (ER15-1867)	Jul 1	FERC accepts terminations
10	CSO Termination: Efficiency Maine Trust (ER15-1866)	Jul 1	FERC accepts termination
10	eTariff Corrections (ER15-1768)	Jul 15	FERC accepts corrections
10	IMM FCM Mitigation Package (ER15-1650)	Jun 30 Jul 22 Jul 30	FERC accepts in part, and rejects in part, proposed changes; ISO directed to file tariff changes removing proposed Static De-List Bid changes by Jul 30 MC unanimously recommends Participants Committee support for proposed compliance changes ISO files compliance changes; comment date Aug 20
11	DNE Dispatch Changes (ER15-1509)	Jul 23	FERC accepts, in part, and rejects, in part, MR1 revisions; FERC directs compliance filing due on or before Aug 24
12	Demand Curve Changes (ER14-1639)	Jul 2 Jul 7 Jul 8	ISO answers NEPGA request that the FERC order Zonal Curves for effect in FCA-10 EPSA submits comments supporting NEPGA request NEPOOL submits comments

#### IV. OATT Amendments / TOAs / Coordination Agreements

* 13	ISO <i>Order 676-H</i> Compliance: Additional Schedule 24 Revisions (ER15-519)	Jul 20	ISO submits additional compliance filing; comment date Aug 10
13	TOs <i>Order 676-H</i> Compliance: Additional OATT Revisions (ER15-517)	Jul 16	TOs submit additional compliance filing; comment date Aug 6
14	Second <i>Order 1000</i> Interregional Compliance Filings (ER13-1960; ER13-1957)	Jul 13 Aug 3	ISO files revisions to ISO-NE Tariff and Protocol in response to the <i>Order 1000 Interregional Compliance Filing Order</i> NEPOOL files comments supporting Protocol changes
14	<i>Order 1000</i> Compliance Filing (ER13-193; ER13-196)	Jun 26	LS Power answers ISO Jun 18 answer

#### V. Financial Assurance/Billing Policy Amendments

*No Activity to Report*

#### VI. Schedule 20/21/22/23 Changes

* 15	Schedule 23: GMP SGIA (ER15-1838)	Jul 28	ISO and GMP file SGIA; comment date Aug 18
15	Schedule 21-NEP: MECO/Paxton Facilities Coord. & Backup Service Agreement (ER15-1838)	Jul 15	FERC accepts Agreement, effective Apr 1, 2015
15	Schedule 21-UI: Pootatuck Project Non-Pool Supported Cost Recovery (ER15-1808)	Jul 1	FERC accepts Pootatuck revisions to Schedule 21-UI

16	LGIA – NU/CPV Towantic (ER15-200)	Jun 29 Jul 1  Jul 14  Jul 17 Aug 4	FERC Staff supports Settlement Agreement CPV Towantic submits reply requesting prompt FERC order accepting Settlement Agreement Trial Judge Sterner certifies uncontested settlement to the Commission Chief Judge Wagner terminates settlement judge procedures FERC approves settlement
16	Schedule 21-FG&E Annual Informational Filing (ER09-1498)	Jun 25	FG&E submits annual update to its Revenue Requirement recovered through the ISO Tariff and Schedule 21-FG&E for the Jun 1, 2015 – May 31, 2016 period
* 16	Schedule 21-NSTAR Annual Informational Filing (ER09-1243; ER07-549)	Jun 30	NSTAR submits CWIP supplement to Jun 1 annual informational filing
* 16	Schedule 21-CMP Annual Informational Filing (ER09-938)	Jun 30	CMP files updated formula rates reflecting actual 2014 cost data and estimated 2015 cost data

### VII. NEPOOL Agreement/Participants Agreement Amendments

*No Activity to Report*

### VIII. Regional Reports

* 17	Opinion 531-A Refund Report: FG&E (EL11-66)	Jun 29	FG&E files refund report
17	Capital Projects Report - 2015 Q1 (ER15-1710)	Jun 26	FERC accepts 2015 Q1 Report
* 17	LFTR Implementation: 26 <sup>th</sup> Quarterly Status Report (ER07-476)	Jul 15	ISO files its 27th quarterly report

### IX. Membership Filings

* 18	August 2015 Membership Filing (ER15-2339)	Jul 31	Memberships: AmericaWide Energy; CLEARResult Consulting; Guzman Energy; and Harborside Energy of Massachusetts; comment date Aug 21
18	July 2015 Membership Filing (ER15-2088)	Jun 30  Jul 27	Memberships: Bucksport Generation; Bath Iron Works and Longreach Energy; Interstate Gas Supply; Terminations: Great Bay Energy IV, LaBree's Inc. and LaBree's Energy, Solios Power FERC accepts filing
18	June 23, 2015 Membership Filing (ER15-1959)	Jul 22	FERC accepts New England Energy Connection membership and Talen Energy Marketing name change
18	June 2015 Membership Filing (ER15-1807)	Jul 2	FERC accepts May 1 termination of New England ITC


### X. Misc. - ERO Rules, Filings; Reliability Standards

* 19	FFT Report: July 2015 (NP15-32)	Jul 30	NERC files report
* 19	FFT Report: June 2015 (NP15-30)	Jun 30	NERC files report
* 19	Revised Reliability Standards: PRC-004-5; PRC-010-2 (RD15-5)	Jul 7	NERC files revised VRFs; comment date Aug 7
19	Revised Reliability Standard: CIP-014-2 (RD15-4)	Jul 14	FERC approves CIP-014-2, effective Jul 14
20	NOPR: Revised CIP Reliability Standards (RM15-14)	Jul 16	FERC issues NOPR proposing to approve Revised CIP Standards (includ. Supply Chain Cyber Controls); comment date Sep 21


20	NOPR: New Reliability Standard: TPL-007-1 (RM15-11)	Jul 20-28	Over 20 parties submit comments, including ISO-NE with other RTO/ISOs, EEI, Exelon, and NERC
22	NOPR: Revised Reliability Standard: PRC-002-2 (RM15-4)	Jul 13	NERC submits reply comments
* 23	Compliance Filing: BES Exclusions for Local Network Configurations (RM12-6)	Jul 1	NERC identifies in detail the types of local network configurations that may be excluded from the bulk electric system
* 23	Removal of LSEs from Compliance Registry (RR15-4)	Jul 17	NERC files to remove the LSE category from the NERC Compliance Registry; comment date Aug 17
* 23	Revised Regional Delegation Agreements (RR15-12)	Jun 26 Jul 27	NERC files revised RDAs APPA/TAPS, Large Public Power Council, PUD1 of Snohomish County, WA, and Avista, Idaho Power, Portland General Electric, Puget Sound Energy, and the Tri-State Generation Association submit comments

<b>XI. Misc. - of Regional Interest</b>	
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* 25	Study Agreement Termination: Eversource/Brookfield (ER15-2218)	July 16	Eversource files notice of termination of Study Agreement; comment date Aug 6
* 25	E&P Agreement MEPCO/Number Nine Wind Farm (ER15-2060)	Jun 29	MEPCO files Amended and Second Restated E&P Agreement
* 26	FERC Enforcement Action: Staff Notices of Alleged Violations (Etracom/M. Rosenberg)	Jul 27	Staff issues notice of preliminary determination that Etracom violated the FERC's Anti-Manipulation Rule (CAISO trades)
27	FERC Enforcement Action: City Power Marketing and Tsingas (IN15-5)	Jul 2	FERC finds City Power Respondents violated Anti-Manipulation Rules by engaging in fraudulent PJM Up To Congestion transactions; disgorgement of <b>\$1,278,358</b> and <b>\$15 million</b> in civil penalties

<b>XII. Misc. - Administrative &amp; Rulemaking Proceedings</b>	
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28	AWEA Petition for LGIA/LGIP Rulemaking (RM15-21)	Jul 23	FERC extends date for comments on AWEA Petition to Sep 8
* 28	Order 812: Revisions to Public Utility Filing Requirements (RM15-3)	Jul 16	FERC issues Order 812; effective date Oct 6, 2015

<b>XIII. Natural Gas Proceedings</b>	
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31	Order 809: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (RM14-2)	Jul 31	FERC issues order clarifying Order 809's implementation date and directing initial comments on the proposed default recall rights for capacity release transactions by Aug 20; reply comments by Aug 31
* 32	Enforcement Actions: Columbia Gas Transmission, LLC (IN15-7)	Jul 16 Jul 30	FERC Staff issues notice of alleged violation FERC approves <b>\$350,000</b> civil penalty for Columbia Gas failure to post notices of auctions of its available firm capacity on the public side of its electronic bulletin board

<b>XIV. State Proceedings &amp; Federal Legislative Proceedings</b>	
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*No Activity to Report*

**XV. Federal Courts**



*	34	Base ROE Complaints (2012 and 2014) (15-1212)	Jul 13 Jul 16	TOs appeal 2012 and 2014 Base ROE Complaint decisions Court issues scheduling order
	34	<i>Order 1000</i> Compliance Filings (15-1139**)	Jul 2 Jul 16	Court grants all motions to intervene Court directs parties to submit proposed briefing formats within 30 days
	34	Base ROE Complaint (2011) (15-1118)	Jul 9	Court directs parties to file proposed briefing formats by Aug
	35	Demand Curve Changes (15-1070**)	Jun 26	CT PURA requests permission to file its own brief in support of FERC; NESCOE, CPV, NHEC file statement re: briefing format
	35	FCA8 Results (14-1244, 14-1246 (consolidated))	Jul 1	Court issues briefing schedule
	36	Orders 745 and 745-A (FERC v. EPSA, Supreme Court, 14-840 and 14-841)	Jul 9 Jul 16 Jul 29	EnerNOC, FERC, CA PUC, Joint States, PJM submit briefs Amicus curiae briefs submitted Oral argument scheduled for Oct 14, 2015

## M E M O R A N D U M

**TO:** NEPOOL Participants Committee Member and Alternates

**FROM:** Patrick M. Gerity, NEPOOL Counsel

**DATE:** August 6, 2015

**RE:** Status Report on Current Regional Wholesale Power and Transmission Arrangements Pending Before the Regulators, Legislatures, and Courts

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission (“FERC”), state regulatory commissions, and the Federal Courts and legislatures through August 5, 2015. If you have questions, please contact us.<sup>1</sup>

<b>I. Complaints</b>
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- **NRG Canal 2 2015/16 ARA3 Complaint/Waiver Request (EL15-57)**

On July 16, the FERC denied the emergency complaint and alternative waiver request filed by GenOn Energy Management, which related to the third annual reconfiguration auction (“ARA”) for the 2015/16 Capacity Commitment Period (“2015/16 ARA3”).<sup>2</sup> As previously reported, GenOn requested that the FERC find that the ISO violated the Tariff in conducting the 2015/16 ARA by submitting a demand bid into the March 2015 ARA as if Unit 2 at the Canal Generating Plant (“NRG Canal 2”) was still de-rated (303 MW), rather than treating Canal 2 at its full capability (577 MW). Absent that finding, GenOn requested waiver of all necessary Tariff provisions to permit the ISO to recalculate the results of the 2015/16 ARA3 to reflect NRG Canal 2’s full capability.

In denying the Complaint and waiver request, the *Canal 2 Order* found that the ISO reasonably determined GenOn’s restoration plans were not submitted within the 10-day window required by the Market Rules and reasonably interpreted “in effect after the most recently completed winter period” with respect to Canal 2’s winter Seasonal Claimed Capability as requiring the use of a figure in effect “as of or very shortly after” the most recently completed winter period, rather than the value taken eight months after the end of the winter period as GenOn had argued.<sup>3</sup> The *Canal 2 Order* denied GenOn’s waiver request because GenOn’s request did not meet the FERC’s standards for such a waiver and the FERC found “no reason to disrupt market participants’ settled expectations under the circumstances presented.”<sup>4</sup> The FERC again emphasized that “[i]t is important to abide by the FCM rules, including deadlines, in order to enable ISO-NE to effectively administer its capacity market.”<sup>5</sup> Challenges, if any, to the *Canal 2 Order* are due on or before August 17.

If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; [dtodot@daypitney.com](mailto:dtodot@daypitney.com)) or Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

<sup>1</sup> 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” or “ISO-NE”) Transmission, Markets and Services Tariff (the “Tariff”).

<sup>2</sup> *GenOn Energy Management, LLC v. ISO New England Inc.*, 152 FERC ¶ 61,044 (July 15, 2015) (“*Canal 2 Order*”).

<sup>3</sup> *Id.* at PP 41-46.

<sup>4</sup> *Id.* at PP 48-49.

<sup>5</sup> *Id.* at P 50.

- **NEPGA Peak Energy Rent (PER) Complaint (EL15-25)**

Rehearing remains pending of the FERC's January 30 order denying NEPGA's PER Complaint.<sup>6</sup> As previously reported, the *PER Complaint Order* found that NEPGA had failed to meet its burden under Section 206 of the Federal Power Act to demonstrate that the existing ISO Tariff provisions were unjust and unreasonable.<sup>7</sup> On March 2, NEPGA and Entergy challenged the *PER Complaint Order*. NEPGA argued the FERC should "reverse its finding ... that NEPGA did not satisfy its Section 206 burden in the Complaint with respect to the relief sought for Capacity Commitment Periods 5 through 8" and "clarify that the [FERC], not the complainant, carries the burden under Section 206 of establishing a just and reasonable "replacement" rate". If rehearing is denied, NEPGA asked the FERC to clarify that it "did not intend to prejudge any future proceeding on the PER Adjustment issue by establishing a required evidentiary standard" in the *PER Complaint Order*. In its request, Entergy, adopting and incorporating NEPGA's request, provided additional bases to support its request for rehearing of the *PER Complaint Order*. Entergy challenged further the FERC's reliance on (i) the ISO's assessment of the PER adjustment's reliability impacts and, with respect to Capacity Commitment Periods 5-8, (ii) the stakeholder process considering changes to the PER rules. On April 1, 2015, the FERC issued a tolling order affording it additional time to consider NEPGA's and Entergy's rehearing requests, which remain pending before the FERC. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; [jfagan@daypitney.com](mailto:jfagan@daypitney.com)) or Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

- **New Entry Pricing Rule Complaint (EL15-23)**

Exelon and Calpine's request for rehearing of the FERC's January 30 order denying the New Entry Pricing Rule Complaint<sup>8</sup> remains pending. As previously reported, the *New Entry Pricing Rule Complaint Order* found that Exelon and Calpine had failed to show that the existing pricing rules governing lock-in capacity result in unjust, unreasonable or unduly discriminatory price suppression. In their rehearing request, Exelon and Calpine assert, among other things, that the *New Entry Pricing Rule Complaint Order* (i) did not provide a reasoned basis for finding that there is no artificial price suppression in post-entry FCAs; (ii) did not address Exelon/Calpine's arguments regarding artificial price suppression in the entry FCA; and (iii) ignored arguments regarding the undue discrimination that results from the current Market Rules. On April 1, 2015, the FERC issued a tolling order affording it additional time to consider Exelon's and Calpine's rehearing request, which remains pending before the FERC. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; [dt\\_doot@daypitney.com](mailto:dt_doot@daypitney.com)) or Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

- **NEPGA DR Capacity Complaint (EL15-21)**

NEPGA's November 14, 2014 complaint remains pending before the FERC. As previously reported, the complaint requests that (i) Demand Response ("DR") Capacity Resources be disqualified from FCA9 and (ii) the Tariff be revised to exclude DR from FCM participation going forward (as a result of *EPSA v. FERC*). Interventions were filed by AEP, Brookfield, Calpine, ConEd, CSG, Direct, Dominion, EEI, ELCON, Emera, EnergyConnect, EnerNOC, Entergy, Exelon, FirstEnergy, Maryland Public Service Commission ("MD PSC"), NextEra, NRG, PPL, and Wal-Mart stores. NEPOOL filed comments on November 26 asking the FERC to reject the NEPGA Complaint without prejudice to a complaint being resubmitted if and as

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<sup>6</sup> *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 150 FERC ¶ 61,053 (Jan. 30, 2015) ("*PER Complaint Order*"), *reh'g requested*.

<sup>7</sup> NEPGA's Dec. 3, 2014 complaint requested that the ISO be directed (i) to increase the daily PER Strike Price by \$250/MWh for Capacity Commitment Periods 5 through 8, and (ii) to eliminate the PER Adjustment for FCA9 and beyond, or, alternatively, to continue the \$250 per MWh increase in the PER Strike Price for FCA9. The changes proposed in the Complaint were considered but not supported by the Participants Committee at its Oct. 3, 2014 meeting.

<sup>8</sup> The FERC stated that much of the complainants' argument rested on the assertion that ISO-NE's lock-in resource requirements differ from PJM's. The FERC acknowledged that ISO-NE's and PJM's differing mechanics may yield different prices paid to existing resources, but the FERC was not persuaded that the difference itself renders ISO-NE's rules unjust and unreasonable. *Exelon Corp. and Calpine Corp. v. ISO New England Inc.*, 150 FERC ¶ 61,067 at P 35 (Jan. 30, 2015) ("*New Entry Pricing Rule Complaint Order*"), *reh'g requested*.

appropriate following consideration of specifically-proposed changes to the Tariff within the Participant Processes. Eversource and UI jointly protested the complaint on December 3, requesting that the FERC either dismiss or hold the Complaint in abeyance. The ISO answered the Complaint on December 4. Also on December 4, Advanced Energy Management Alliance, NESCOE, Conn/RI,<sup>9</sup> Enerwise, Environmental Advocates,<sup>10</sup> NGrid, Public Systems, and the Sustainable FERC Project opposed the Complaint; EPSA and PSEG supported the Complaint; Genbright submitted comments. On December 15, CT PURA moved to lodge the December 15 DC Circuit Court order extending the stay of the mandate in *EPSA v. FERC*. On December 19, NEPGA answered the ISO response and the other pleadings submitted in response to its Complaint. On January 7, just as they had on December 23 in the FirstEnergy Complaint (*see* Section XI below), Environmental Advocates moved to lodge the US Solicitor General's application for an extension of time in which to file a petition for writ of certiorari, the Supreme Court Clerk's notice to the DC Circuit that the extension had been granted, and the DC Circuit's order extending the stay of its mandate pending the Supreme Court's final disposition of the writ of certiorari. As noted, this matter remains pending before the FERC. If you have any questions concerning these matters, please contact Dave Doot (860-275-0102; [dtdoot@daypitney.com](mailto:dtdoot@daypitney.com)) or Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

- **206 Proceeding: Importers' FCA Offers Review/Mitigation (EL14-99; ER15-117)**

As previously reported, the FERC initiated this proceeding, on September 16, 2014, pursuant to Section 206 of the Federal Power Act ("FPA"). The FERC directed the ISO to either revise its Tariff to provide for the review and potential mitigation of importers' offers prior to each annual Forward Capacity Auction ("FCA") or show cause why it should not be required to do so.<sup>11</sup> The FERC directed the ISO to submit those Tariff revisions or support for why Tariff revisions should not be required on or before October 16, 2014. September 24, 2014 was the refund effective date.<sup>12</sup> On October 16, the ISO submitted Tariff revisions in response to the Show Cause Order and Public Citizen requested that the FERC expand this proceeding (i) to determine whether the rates produced by FCA8 are just and reasonable and if not, to fix the just and reasonable rates to be charged; and (ii) to include in this proceeding "stakeholder reform and transparency". On December 15, 2014, the FERC conditionally accepted, subject to two additional compliance filings, the ISO's October 16 Tariff revisions.<sup>13</sup> Each of the additional compliance filings have been filed and accepted.<sup>14</sup> All remaining requests and protests, including those of Public Citizen, were rejected. Public Citizen requested rehearing of the *Imports Mitigation Order* on January 14, 2015 (ER15-117-003). On January 26, NEPGA answered Public Citizen's request. On February 12, 2015, the FERC issued a tolling order affording it additional time to consider Public Citizen's rehearing request, which remains pending before the FERC. Other than FERC action on the January Public Citizen rehearing request, this matter is concluded. If you have any questions concerning these matters, please contact Dave Doot (860-275-0102; [dtdoot@daypitney.com](mailto:dtdoot@daypitney.com)), Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)), or Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

<sup>9</sup> "Conn/RI" is the Connecticut Public Utilities Regulatory Authority ("CT PURA"), George Jepsen, Att'y Gen. for the State of Conn. ("CT AG"), the Conn. Department of Energy and Environmental Protection ("CT DEEP"), the Conn. Office of Consumer Counsel ("CT OCC"), and the Rhode Island Div. of Public Utilities and Carriers ("RI PUC").

<sup>10</sup> "Environmental Advocates" are the Sustainable FERC Project, Sierra Club, Environmental Defense Fund, and Acadia Center.

<sup>11</sup> *ISO New England Inc.*, 148 FERC ¶ 61,201 (Sep. 16, 2014) ("*September 16 Order*").

<sup>12</sup> The Sep. 17 notice of this proceeding was published in the *Fed. Reg.* on Sep. 24, 2014 (Vol. 79, No. 185) p. 57,075.

<sup>13</sup> *ISO New England Inc.*, 149 FERC ¶ 61,227 (2014) ("*Imports Mitigation Order*"), *reh'g requested*.

<sup>14</sup> The first compliance filing corrected an incorrect cross-reference in Section III.13.1.3.5.7 (Qualification Determination Notification for New Import Capacity Resources). The second compliance filing included tariff revisions "which allow importers to submit up to five price-quantity pairs, together with any necessary mitigation provisions to address the exercise of market power" for implementation in FCA-10.

- **Base ROE Complaints (2012 and 2014) Consolidated (EL13-33 and EL14-86)**

As previously reported, the FERC, in response to second (EL13-33<sup>15</sup>) and third (EL14-86<sup>16</sup>) complaints regarding the TOs' 11.14% return on equity ("Base ROE"), issued orders establishing trial-type, evidentiary hearings and separate refund periods. The first, in EL13-33, was issued on June 19, 2014 and established a 15-month refund period of December 27, 2012 through March 27, 2014;<sup>17</sup> the second, in EL14-86, was issued on November 24, 2014, established a 15-month refund period beginning July 31, 2014,<sup>18</sup> and, because of "common issues of law and fact", consolidated the two proceedings for purposes of hearing and decision, with the FERC finding it "appropriate for the parties to litigate a separate ROE for each refund period."<sup>19</sup> The TOs requested rehearing of both orders. On May 14, the FERC denied rehearing of both orders.<sup>20</sup> On July 13, the TOs appealed those order to the DC Circuit Court of Appeals (see Section XV below).

**Hearings.** The hearings in this mater began June 25, 2015 and were completed on July 2. Just prior to the commencement of the hearing, pursuant to an unopposed motion of the TOs, Judge Sterner adopted a proposed protective order to permit the exchange and use during hearing of certain confidential materials provided by Thomson Reuters. Joint Transcript Corrections and a Final Index of Exhibits were submitted on July 13, 2015. Judge Sterner adopted the transcript corrections on July 15. On July 23, the TOs filed a motion to lodge portion of testimony filed in the Southwestern Public Service Co. ROE proceeding (EL15-8) to show inconsistent positions of FERC Trial Staff. On July 29, 2015, a Joint Procedural History was submitted, as were initial briefs by the Complainant-Aligned Parties, TOs, EMCOS and FERC Staff. The next procedural milestone will be the submission of Reply Briefs and a Joint List of Appearances, which are due on August 26, 2015. As noted previously, an initial decision is to be issued by December 30, 2015. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; [jfagan@daypitney.com](mailto:jfagan@daypitney.com)) or Eric Runge (617-345-4735; [ekrunge@daypitney.com](mailto:ekrunge@daypitney.com)).

- **206 Investigation: FCM Performance Incentives (Compliance Proceedings) (EL14-52; ER14-2419)**

Rehearing remains pending of the FERC's May 30, 2014 *PI Order*<sup>21</sup> on the FCM PI Jump Ball Filing and its *October 2 Order*<sup>22</sup> on the first compliance filing in response to the *PI Order*. As previously reported, the FERC instituted this proceeding, pursuant to Section 206 of the FPA, in its May 30 *PI Order* on the FCM

<sup>15</sup> The 2012 Base ROE Complaint, filed by Environment Northeast (now known as Acadia Center, "ENE"), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"), challenged the TOs' 11.14% return on equity, and seeks a reduction of the Base ROE to 8.7%.

<sup>16</sup> The 2014 Base ROE Complaint, filed July 31, 2014 by the Massachusetts Attorney General ("MA AG"), together with a group of State Advocates, Publicly Owned Entities, End Users, and End User Organizations (together, the "2014 ROE Complainants"), seeks to reduce the current 11.14% Base ROE to 8.84% (but in any case no more than 9.44%) and to cap the Combined ROE for all rate base components at 12.54%. 2014 ROE Complainants state that they submitted this Complaint seeking refund protection against payments based on a pre-incentives Base ROE of 11.14%, and a reduction in the Combined ROE, relief as yet not afforded through the prior ROE proceedings.

<sup>17</sup> *Environment Northeast, et al. v. Bangor Hydro-Elec. Co., et al.*, 147 FERC ¶ 61,235 (June 19, 2014) ("2012 Base ROE Initial Order"), *reh'g denied*, 151 FERC ¶ 61,125 (May 14, 2015).

<sup>18</sup> *Mass. Att'y Gen. et al. -v- Bangor Hydro et al.*, 149 FERC ¶ 61,156 (Nov. 24, 2014), *reh'g denied*, 151 FERC ¶ 61,125 (May 14, 2015).

<sup>19</sup> *Id.* at P 27 (for the refund period covered by EL13-33 (i.e., Dec. 27, 2012 through Mar. 27, 2014), the ROE for that particular 15-month refund period should be based on the last six months of that period; the refund period in EL14-86 and for the prospective period, on the most recent financial data in the record).

<sup>20</sup> *Environment Northeast, et al. v. Bangor Hydro-Elec. Co., et al. and Mass. Att'y Gen. et al. -v- Bangor Hydro et al.*, 151 FERC ¶ 61,125 (May 14, 2015).

<sup>21</sup> *ISO New England Inc. and New England Power Pool*, 147 FERC ¶ 61,172 (May 30, 2014) ("*PI Order*"), *clarif. and reh'g requested*.

<sup>22</sup> *ISO New England Inc.*, 149 FERC ¶ 61,009 (Oct. 2, 2014) ("*October 2 Order*"), *reh'g requested*.

Performance Incentives Jump Ball filing. In the *PI Order*, the FERC concluded that the ISO's FCM payment design was "unjust and unreasonable, because it fails to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits."<sup>23</sup> The FERC directed the ISO to submit "Tariff revisions reflecting a modified version of its [PFP] proposal and an increase in the Reserve Constraint Penalty Factors, consistent with NEPOOL's proposal."<sup>24</sup> The FERC-established refund effective date was June 9, 2014.<sup>25</sup> Requests for clarification and/or rehearing of the *PI Order* were filed by: NEPOOL, Connecticut and Rhode Island,<sup>26</sup> Dominion, MMWEC, Indicated Generators,<sup>27</sup> NEPGA, NextEra, Potomac Economics, and PSEG/NRG. On July 28, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC.

***FCM PI Jump Ball Compliance Filing I (ER14-2419-001)***. On October 2, 2014, the FERC accepted in part, subject to condition, and rejected in part, the ISO's July 14, 2014 compliance filing ("Compliance Filing I") that, as previously reported, had been filed in response to directives in the *PI Order*. While accepting nearly all of the provisions proposed in Compliance Filing I, the *October 2 Order* rejected the ISO's compliance proposal concerning improper price signals caused by binding intra-zonal transmission constraints.<sup>28</sup> The FERC found that an exemption was not necessary for resources on the export side of an intra-zonal transmission constraint during a Capacity Scarcity Condition and directed the ISO to submit a further compliance filing (since filed and accepted) to revise Market Rule Section 13.7 by removing the language that reflected that aspect of the ISO's July 14 compliance proposal and restoring language in Sections III.13.7.2.2(a) and III.13.7.2.2(b) ISO-NE originally proposed by the ISO in its January 17 Filing. The Tariff sections accepted were accepted effective June 9, 2014, December 3, 2014, and June 1, 2018, as requested.<sup>29</sup> Connecticut/Rhode Island<sup>30</sup> and Public Systems<sup>31</sup> requested rehearing of the *October 2 Order* on November 3, 2014. On December 3, 2014, the FERC issued a tolling order affording it additional time to consider the rehearing requests, which remain pending before the FERC.

If you have any questions related to these proceedings, please contact Dave Doot (860-275-0102; [dttdoot@daypitney.com](mailto:dttdoot@daypitney.com)), Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)), or Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

- **206 Investigation: Consistency of ISO-NE (DA) Scheduling Practices with Natural Gas Scheduling Practices to be Adopted in Docket RM14-2 (EL14-23)**

As previously reported, on March 20, 2014, the FERC initiated this proceeding, pursuant to Section 206 of the FPA, to ensure that the ISO's scheduling, particularly its Day-Ahead scheduling practices, correlate with any revisions to the natural gas scheduling practices to be ultimately adopted by the FERC in RM14-2 (*see* Section XIII below).<sup>32</sup> Noting its concern about the lack of synchronization between the Day-

<sup>23</sup> *PI Order* at P 23.

<sup>24</sup> *Id.* at P 1.

<sup>25</sup> The June 3 notice of this proceeding was published in the *Fed. Reg.* on June 9, 2014 (Vol. 79, No. 110) pp. 32,937-89.

<sup>26</sup> "Connecticut and Rhode Island" are: the CT PURA, CT OCC, CT AG, CT DEEP, the United Illuminating Company ("UI") and the RI PUC.

<sup>27</sup> "Indicated Generators" are: Exelon Corp. ("Exelon"), EquiPower Resources Management, LLC ("EquiPower"), Essential Power, LLC ("Essential Power"), and Dynegy Marketing and Trade, LLC and Casco Bay Energy Company, LLC (together, "Dynegy").

<sup>28</sup> *October 2 Order* at P 56.

<sup>29</sup> *October 2 Order* at P 1; Ordering Paragraph (A).

<sup>30</sup> "Connecticut/Rhode Island" are the CT PURA, CT AG, CT OCC, CT DEEP, and the RI PUC.

<sup>31</sup> "Public Systems" are CMEEC, MMWEC, NHEC, and VEC.

<sup>32</sup> *Cal. Indep. Sys. Op. Corp. et al.*, 146 FERC ¶ 61,202 (Mar. 20, 2014). The New England 206 proceeding was docketed as EL14-23.

Ahead scheduling practices of interstate natural gas pipelines and electricity markets, the FERC directed each ISO and RTO, including ISO-NE, within 90 days after publication of a Final Rule in Docket RM14-2 in the *Federal Register* (or, as discussed in Section XIII below, Thursday, July 23, 2015):

(1) to make a filing that proposes tariff changes to adjust the time at which the results of its day-ahead energy market and reliability unit commitment process (or equivalent) are posted to a time that is sufficiently in advance of the Timely and Evening Nomination Cycles, respectively, to allow gas-fired generators to procure natural gas supply and pipeline transportation capacity to serve their obligations, or (2) to show cause why such changes are not necessary. In their responses, each ISO and RTO must explain how its proposed scheduling modifications are sufficient for gas-fired generators to secure natural gas pipeline capacity prior to the Timely and Evening Nomination Cycles.<sup>33</sup>

**ISO Response to Show Cause Order.** On July 23, the ISO filed its response. In that filing, the ISO described why changes to the time at which the results of the Day-Ahead Energy Market and RAA process are posted are not necessary in response to the FERC's rule making. Comments on the ISO's filing are due on or before August 18, 2015. The FERC expects to issue a final order in this Section 206 proceeding by October 21, 2015 (or within 90 days of the filings required under the March 20 order). If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; [dt\\_doot@daypitney.com](mailto:dt_doot@daypitney.com)), Joe Fagan (202-218-3901; [jfagan@daypitney.com](mailto:jfagan@daypitney.com)), or Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

## II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA9 Results Filing (ER15-1137)**

As previously reported, the FERC accepted, on June 18, the results of the ninth FCA ("FCA9"), effective June 27, 2015, as requested.<sup>34</sup> On July 20, 2015, the Utility Workers Union of America Local 464 and Robert Clark ("UWUA") requested rehearing of the *FCA9 Results Order*. The UWUA request for clarification is pending before the FERC, with FERC action required on or before August 19, 2015, or the UWUA request will be deemed denied. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)) or Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **Opinion 531-A Compliance Filing: TOs (ER15-414)**

On July 8, the FERC accepted the TO's amended *Opinion 531-A* compliance filing. As previously reported, the New England TOs submitted, on November 17, 2014, tariff changes to both the regional and local rates in the ISO OATT in response to *Opinion 531-A*.<sup>35</sup> Protests to that filing were submitted by EMCOS and the Complainant-Aligned Parties. In light of *Opinion 531-B*, the TOs indicated in a March 31 motion that further amendments would be required (and that such amendments would likely resolve the contested issues raised by EMCOS and Complainant-Aligned Parties) and requested that the FERC defer action on the compliance filing until after the amendments were filed and the corresponding period for comments passed. The TOs submitted their amended *Opinion 531-A* compliance filing on April 22. They indicated that the April 22 filing reflected certain clarifications provided in *Opinion 531-B* and amended the

<sup>33</sup> *Id.* at P 19.

<sup>34</sup> *ISO New England Inc.*, 151 FERC ¶ 61,226 (June 18, 2015) ("*FCA9 Results Filing*").

<sup>35</sup> Specifically, Section II.A.2.(a)(iii) of the Attachment F Implementation Rule was revised to reflect an ROE of 11.07% – the 10.57% base ROE directed by the Commission in *Opinion 531-A* plus the 50 basis point adder for ISO-NE participation. The TOs also revised Section II.A.2.(a)(iii) of the Attachment F Implementation Rule to require the PTOs to calculate their total ROE each year under both regional and local rates and to reduce any ROE incentives included in regional rates to the extent necessary to ensure that the PTOs' total ROE does not exceed 11.74% (the TOs' maximum ROE as identified by the FERC). The TOs also revised a number of provisions of the Attachment F Implementation Rule to include cross-references to Section II.A.2.(a)(iii).

Attachment F Annual Transmission Revenue Requirements used for determining RNS rates and the Schedule 21 Local Service Schedules for determining revenue requirements applicable to the TOs. No comments on the amended *Opinion 531-A* compliance filing were filed. As noted above, the amended *Opinion 531-A* compliance filing was accepted on July 8, effective October 16, 2014, as requested. Unless the July 8 order is challenged, with any challenges due on or before August 7, this proceeding will be concluded. If you have any questions concerning these matters, please contact Joe Fagan (202-218-3901; [jfagan@daypitney.com](mailto:jfagan@daypitney.com)) or Eric Runge (617-345-4735; [ekrunge@daypitney.com](mailto:ekrunge@daypitney.com)).

- **2015/16 Power Year Transmission Rate Filing (ER09-1532; RT04-2)**

On July 31, 2015, the Participating Transmission Owners (“PTOs”) Administrative Committee (“PTO AC”) submitted a filing identifying adjustments to regional transmission service charges under Section II of the ISO Tariff for the period June 1, 2015 through May 31, 2016. The filing reflected the charges to be assessed under annual transmission formula rates, reflecting actual 2014 cost data, Forecasted Annual Transmission Revenue Requirements associated with projected PTF additions for the 2015 Forecast Period, and the Annual True-up including associated interest. The PTO AC states that the annual updates results in a Pool “postage stamp” RNS Rate of \$98.70 /kW-year effective June 1, 2015, an increase of \$8.90 /kW-year from the charges that went into effect on June 1, 2014. In addition, the annual update to the Schedule 1 formula rate results in a charge of \$1.61 kW-year, a \$0.09/kW-year decrease over the Schedule 1 charge that last went into effect on June 1, 2014. This filing was reviewed at the July 14-15 RC/TC Summer Meeting. The filing will not be noticed for public comment. If there are questions on this proceeding, please contact Eric Runge (617-345-4735; [ekrunge@daypitney.com](mailto:ekrunge@daypitney.com)).

- **2014/15 Power Year Transmission Rate Filing: Public Representatives’ Protest (ER09-1532; RT04-2)**

On April 28, 2015, “Public Representatives”<sup>36</sup> filed a protest, in part, of the July 31, 2014 PTO AC filing identifying adjustments to regional transmission service charges under Section II of the ISO Tariff for the period June 1, 2014 through May 31, 2015. Specifically, Public Representatives protest the Annual Transmission Revenue Requirements calculation and the resulting RNS rates to the extent they included planning costs for NHT’s proposed “SeaLink” project, costs they asserted were contrary to the terms of the TOA and should be disallowed from RNS rate recovery. Public Representatives stated that the partial protest was filed in April 2015, rather than closer to the July 2014 informational filing, due to lengthy, but unsuccessful, discussions between the MA AG’s office and NHT to resolve this dispute. Interventions were filed by CMP, Eversource, National Grid, and UI. NESCOE filed comments on May 8. On May 15, NHT answered Public Representatives’ protest. There has not been any activity since the last Report and this matter is pending before the FERC. If there are questions on this proceeding, please contact Eric Runge (617-345-4735; [ekrunge@daypitney.com](mailto:ekrunge@daypitney.com)).

- **FCA1 Results Remand Proceeding (ER08-633)**

As previously reported, the DC Circuit issued on December 23, 2011, a *per curiam* order<sup>37</sup> that PSEG’s May 2010 petition for review be granted, remanding the FERC’s orders in this proceeding<sup>38</sup> for further consideration. In particular, the FERC was directed to (i) determine whether PSEG’s position (that it should receive the full (unprorated) floor price for all its resources that it could not prorate) would be an appropriate way to interpret the then-existing Market Rules and, if not, (ii) respond to PSEG’s objections that

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<sup>36</sup> “Public Representatives” are the MA AG, CT OCC, CT PURA, the RI PUC, the Attorney General of the State of Rhode Island (“RI AG”), the Maine Public Advocate (“MOPA”) and the Vermont Department of Public Service (“VT DPS”).

<sup>37</sup> *PSEG Energy Res. & Trade LLC and PSEG Power Conn. LLC v. FERC*, No. 10-1103, 2011 U.S. App. LEXIS 25659, (D.C. Cir. Dec. 23, 2011).

<sup>38</sup> *ISO New England Inc., 123 FERC ¶ 61,290 (2008); reh’g denied, 130 FERC ¶ 61,235 (2010), remanded, PSEG Energy Res. & Trade LLC and PSEG Power Conn. LLC v. FERC*, No. 10-1103, 2011 U.S. App. LEXIS 25659, (D.C. Cir. Dec. 23, 2011).

any contrary result would result in “undue discrimination” and would be “inconsistent with the fundamental policy goals” of FCM.

On June 2, 2015, in a long-awaited order, the FERC reversed its prior determination and found that, given that the ISO had prohibited resources needed for reliability from prorating quantity based on its interpretation of the Proration Rule, it was appropriate to consider resettlements to those resources that were not able to prorate quantity.<sup>39</sup> “[W]here resources needed for reliability were prohibited from prorating quantity under the Proration Rule, they should have received the full market clearing price for each megawatt offered.”<sup>40</sup> Although the FERC found that the ISO reasonably interpreted the Proration Rule as allowing it to limit certain suppliers’ ability to prorate quantity, in order to maintain reliability, and the FERC disagrees with PSEG’s argument that it would be unduly discriminatory under the FPA to make unavailable to certain resources the option to choose quantity proration instead of price proration, the FERC found that resources prevented from prorating quantity must also receive “a just, reasonable, and not unduly discriminatory or preferential rate,” (i.e. the full clearing price for each megawatt offered).

Accordingly, the FERC established a briefing schedule to permit the parties to address issues relating to the amounts of such resettlements (i.e., the difference between a resource’s actual payment and what the payment would have been had proration of the resource not been rejected for reliability reasons), and the parties to which those payments should be charged and to whom they should be paid (taking into consideration any possible changes in ownership, retirements, or similar new circumstances of the resources in question).

In its initial brief filed on July 17, the ISO identified:

- the Connecticut resources that were unable to prorate quantity in FCA1, and the number of MWs for which each resource received a CSO;
- the resettlements due to each such entity, based on the difference between (1) the prorated price that the resources did receive (4.254/kW-mo.), and (2) the un-prorated capacity clearing price that the resources would have received absent price proration (4.50/kW-mo.), plus interest (total refunds with interest will total approximately \$ 20.4 million);
- the parties to whom the resettlements would be charged (those with Regional Network Load within Connecticut during that time); and
- the mechanism by which the ISO would make such resettlements.

The ISO did not identify any considerations that would render the resettlements inappropriate or difficult. For purposes of its brief, the ISO assumed a December 14, 2015 resettlement date. Initial briefs were also submitted by Bridgeport Energy, Dominion, and Bridgeport Energy. Reply briefs are due on or before August 17, 2015. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)) or Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

### III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **CSO Terminations: Enerwise Global Technologies (ER15-2232)**

Pursuant to Market Rule 1 § 13.3.4(c), the ISO filed on July 21 to terminate CSOs for Resource #s 16700 and 37922 held by Project Sponsor Enerwise Global Technologies (“Enerwise”). The ISO indicated that, upon FERC acceptance of the filing, the ISO will draw down the applicable amount of financial assurance provided by Enerwise with respect to the CSOs and portions of the CSOs being terminated. NEPOOL filed a doc-less

<sup>39</sup> *ISO New England Inc.*, 151 FERC ¶ 61,196 (June 2, 2015) (“*FCA1 Remand Order*”).

<sup>40</sup> *Id.* at P 14.

intervention on July 27. Comments on this filing are due on or before August 11, 2015. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **CSO Termination: Hampshire Council of Governments (ER15-2229)**

Also pursuant to Market Rule 1 § 13.3.4(c), the ISO filed on July 21 to terminate a CSO for Resource # 38110 held by Project Sponsor Hampshire Council of Governments. The ISO indicated that, upon FERC acceptance of the filing, the ISO will draw down the applicable amount of financial assurance provided by the Hampshire Council of Governments with respect to the CSO being terminated. NEPOOL filed a doc-less intervention on July 27. Comments on this filing are due on or before August 11, 2015. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **Jump Ball Filing: Winter Reliability Program (ER15-2208)**

On July 17, the ISO and NEPOOL submitted two alternative versions of Market Rule changes intended to establish a winter reliability program for winters 2015/16, 2016/17 and 2017/18 -- the "NEPOOL Proposal" and the "ISO-NE Proposal".

Both Proposals are intended to address reliability challenges created by the region's increased reliance on natural gas-fueled generation and to be stop-gap measures until revised incentives for capacity resources (PFP) become fully effective in 2018. The NEPOOL Proposal is based on the design of the 2014/15 program, with three main components: (1) compensation for certain oil inventory that remains in New England following the end of each winter period; (2) compensation for unused liquefied natural gas ("LNG") contract volumes; and (3) a supplemental demand response ("DR") program. The ISO Proposal also includes the first two components of the NEPOOL Proposal, but eliminates the DR component, and provides compensation not only for fuel oil and LNG, but also for nuclear, hydro, biomass and coal-fired resources. The NEPOOL Proposal was supported by the Participants Committee at the June 25 session of the Summer Meeting; the ISO Proposal was not. The Proposals were submitted pursuant to "jump ball provision" of the Participants Agreement (Section 11.1.5). Both NEPOOL and the ISO requested a FERC order by Monday, September 14, 2015.

Protests and comments on the Jump Ball Filing were due on or before August 5, 2015. Pleadings and comments supporting the NEPOOL Proposal were filed by **NESCOE**, **CT PURA**, and **TransCanada**. **Essential Power** supported the NEPOOL Proposal, but requested that target fuel inventory be set at 15 days of continuous operation, the same target as for Winter 2014/15, asserting there is no basis for reducing that target to 10 days. **Entergy/NextEra/Dominion** supported the ISO Proposal. **Dynegy/Brayton Point** also supported the ISO Proposal in part, but requested that the ISO be directed to implement an eligible oil inventory limit of at least 15 days and to re-evaluate the volume of necessary fuel inventory prior to each winter season. Protesting both Proposals were **NEPGA/EP SA** (who also requested that ISO-NE be directed to amend the Tariff to define the formula for calculating the Winter Reliability Program payment rate) and **PSEG** (who requested that the FERC direct (i) the ISO and NEPOOL to propose market-based programs for winters 2016/17 and 2017/18; (ii) to the extent that the FERC favors the NEPOOL Proposal, the compensable inventory be increased to 15 days consistent with the previous year's program or in the alternative, require that the ISO confirm that 10 days of oil inventory, as proposed by NEPOOL, is sufficient to ensure regional fuel security for the winter in which the program applies; and (iii) To the extent the FERC favors the ISO Proposal, direct the ISO to demonstrate that expanded eligibility of resource types will result in sufficient incremental on-site inventory (above what might otherwise be available based upon market only signals) and that for the resources that participate in the oil program, only 10 days of oil inventory is sufficient to ensure fuel security for the region for the winter in which the program applies). In addition, interventions were filed by Brookfield, ConEd, Calpine, CT OCC, Emera, Exelon, Eversource, GDF Suez Energy North America, Noble Americas, NRG, UI, VT DPS. This matter is pending before the FERC.

If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; [dt\\_doot@daypitney.com](mailto:dt_doot@daypitney.com)), Joe Fagan (202-218-3901; [jfagan@daypitney.com](mailto:jfagan@daypitney.com)), or Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

- **CSO Terminations: Enerwise Global Technologies (ER15-1944)**

On July 16, the FERC accepted the termination of CSOs for Resources held by Project Sponsor Enerwise. The ISO will draw down the applicable amount of financial assurance provided by Enerwise with respect to these CSOs and portions of these CSOs being terminated. Unless the July 16 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **Waiver Request: FCM Interconnection Deposit Qualification Deadline (Bellingham) (ER15-1934)**

On June 17, Northeast Energy Associates (“NEA”) requested a waiver of the FCM interconnection deposit qualification deadline in order to permit capacity from the Bellingham Energy Center Station that is being developed by Hawkes Meadow to be offered in FCA-10. NEA reported that the \$50,000 interconnection deposit associated with NEA’s efforts to increase Bellingham’s qualified capacity by approximately 25 MW was received just before 9am the morning after FCA-10’s March 3 deadline; as a result, the ISO has indicated that it is not able under its Tariff to qualify NEA’s increased capacity for participation in FCA-10. Comments on this waiver request were due on or before July 8, 2015. Doc-less interventions were filed by NEPOOL, Entergy, NESCOE, and NRG. On July 1, the ISO opposed the NEA request (asserting that NEA did not meet the FERC’s standards for a waiver request). NEA answered the ISO’s answer on July 16. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **CSO Terminations: Direct Energy Business (ER15-1867)**

On July 1, the FERC accepted the termination of the CSOs for Resource Nos. 37933, 37929 and 37932 held by Project Sponsor Direct Energy Business. The ISO will draw down the applicable amount of financial assurance provided by Direct Energy with respect to the CSOs being terminated. The July 1 order was not challenged, is final and unappealable, and this proceeding is concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **CSO Termination: Efficiency Maine Trust (ER15-1866)**

Also on July 1, the FERC accepted the termination of a portion of the CSO for Resource No. 38057 held by Project Sponsor Efficiency Maine Trust. The ISO will draw down the applicable amount of financial assurance provided by Efficiency Maine Trust with respect to the portion of the CSO to be terminated. The July 1 order was not challenged, is final and unappealable, and this proceeding is concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **eTariff Corrections (ER15-1768)**

On July 15, the FERC accepted corrections to Section III.10 of the ISO’s eTariff. As previously reported, the correction filed in this proceeding completes Section III.10, which was incomplete in the e-version filed and accepted as part of the February 6 Forward Reserve Obligation Charge Changes (ER15-1009). Unless the July 15 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **IMM FCM Mitigation Package (ER15-1650)**

On June 30, the FERC accepted in part, and rejected in part, revisions to the market power mitigation provisions in the FCM Market Rules (“IMM FCM Mitigation Package”).<sup>41</sup> As previously reported, the Package proposed to (i) establish a revised Pivotal Supplier Test (permitting the IMM to take into account both existing internal resources and import resources when assessing the competitiveness of supply and to conduct the Pivotal Supplier Test closer to the start of an FCA); (ii) increase, beginning with FCA-10, the value below which existing resources that have chosen to be price takers in an FCA can opt to leave the auction (“Dynamic De-List Bid Threshold”), from \$3.94/kW-mo. to \$5.50/kW-mo. (with the value to be recalculated and reviewed with Participants not less than once every three years); and (iii) remove some of the flexibility in the auctions that is

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<sup>41</sup> *ISO New England Inc. and New England Power Pool Participants Comm.*, 151 FERC ¶ 61,270 (June 30, 2015) (“June 30 Order”).

currently afforded to Market Participants submitting Static De-List Bids. In its *June 30 Order*, the FERC accepted the revised Pivotal Supplier Test, the increased Dynamic De-List Bid Threshold, the New Import Capacity Resource mitigation rules, and the clean-up changes proposed in the IMM FCM Mitigation Package. However, the FERC rejected the proposed changes to the Static De-List Bid rules, finding it “inconsistent with competitive market principles to prevent a capacity supplier without buyer-side market power from lowering its offer in the FCA or from withdrawing its Static De-List Bid during the post-review modification period, both actions that would tend to reduce FCA clearing prices.”<sup>42</sup> “Provided that a resource submits a Non-Price Retirement Request before the deadline for such a request,” the [FERC] found “no basis for precluding a supplier from making this decision during the Static De-List Bid finalization process.”<sup>43</sup> Accordingly, the ISO was directed to submit Tariff revisions removing the proposed Static De-List Bid rule changes on or before July 30.<sup>44</sup> Finally, with respect to the competitive entry exemption from buyer-side mitigation advocated by Champlain VT, the FERC found the issue beyond the scope of the proceeding and directed Champlain VT to pursue its concerns in the stakeholder process.<sup>45</sup> The accepted revisions were effective June 1, 2015, as requested. The *June 30 Order* was not challenged and is final and unappealable.

**July 30 Compliance Filing.** On July 30, the ISO submitted Tariff revisions that remove the changes to the Static De-List Bid rules. Those changes were reviewed and unanimously recommended for Participants Committee support by the Markets Committee on July 22. The compliance changes are scheduled for Participants Committee action via the August 7, 2015 Consent Agenda (Item No. 7). Comments on the July 30 compliance filing are due on or before August 20, 2015. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

- **DNE Dispatch Changes (ER15-1509)**

On July 23, the FERC accepted, in part, and rejected, in part, revisions to Market Rule 1, jointly submitted by the ISO and NEPOOL, to provide for the dispatch of certain wind and hydro Intermittent Power Resources using Do Not Exceed (“DNE”) Dispatch Points (“DNE Dispatch Changes”).<sup>46</sup> The accepted DNE Dispatch Changes will become effective April 16, 2016. In response to issues raised by RENEW and SunEdison (“Protestors”), the FERC found that the ISO did not sufficiently justify the blanket exclusion of DNE Dispatchable Generators from the regulation and reserves markets.<sup>47</sup> Accordingly, the FERC directed the ISO “to submit a compliance filing [on or before August 24] to remove the relevant tariff provisions. Furthermore, in recognition of the fact that, as RENEW explains, it is not currently economic for wind resources to participate in the frequency regulation market, we also encourage ISO-NE to work with its stakeholders to develop rules integrating intermittent resources into its markets.”<sup>48</sup> The FERC also encouraged the ISO to work closely with its stakeholders on the issues it found not at issue in this proceeding or settled by the ISO (including implementation and timing issues, including data accuracy, transparency, and constraints to certain hydro resources).<sup>49</sup> Finally, the FERC directed the ISO to correct a typographical error identified by the FERC in Market Rule 1 Section 13.6.2.1.1.2.<sup>50</sup> Challenges, if any, to the *DNE Dispatch Order* will be due on or before August 24. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

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<sup>42</sup> *Id.* at P 44.

<sup>43</sup> *Id.* at P 31.

<sup>44</sup> *Id.*

<sup>45</sup> *Id.* at P 64.

<sup>46</sup> *ISO New England Inc. and New England Power Pool Participants Comm.*, 152 FERC ¶ 61,065 (July 23, 2015) (“*DNE Dispatch Order*”).

<sup>47</sup> *Id.* at P 25.

<sup>48</sup> *Id.*

<sup>49</sup> *Id.* at P 29; n. 75.

<sup>50</sup> *Id.* at PP 30-31.

- **Demand Curve Changes (ER14-1639)**

As previously reported, the FERC denied rehearing of the *Demand Curve Order*,<sup>51</sup> but clarified (agreeing with Exelon and Entergy) that a resource that elects to utilize the renewables minimum offer price rule exemption should not also be allowed to utilize the new resource lock-in).<sup>52</sup> Accordingly, the FERC directed the ISO to submit, on or before March 2, 2015, a compliance filing clarifying that a resource may not utilize both the renewable resource exemption and the new resource price lock-in. That compliance filing was submitted on March 2, accepted on May 1, and became effective on May 2.<sup>53</sup> The petition for DC Circuit Court of Appeals review of the FERC's Demand Curve orders, filed by NextEra, NRG and PSEG, remains pending before that Court (*see* Section XV below).

**Informational Progress Report:** On May 18, the ISO submitted a report to update the FERC on New England's progress toward developing FCM zonal demand curves. Importantly, the ISO reported that improvements to the current FCM demand curve structure cannot be completed before FCA-10, noting that from its perspective and despite efforts to date, the changes have "not yet achieved a design that reasonably satisfies reliability, market efficiency and pricing objectives with reasonable market power protections." The ISO stated that it needs "additional time to address the complexities associated with the demand curve structure ... and commits to filing a further progress report no later than October 31, 2015." In the remainder of the report, the ISO identifies the three fundamental reasons that it believe make it imprudent to immediately adopt a new sloped zonal demand curve design without further analysis and stakeholder review, identifies the four key factors for Demand Curve design, and notes the reliability, price volatility, robustness, and market power concerns. The ISO concludes that "the best approach at this time is to maintain the current demand curve structure for the FCA 10 auction cycle and continue to analyze and discuss with stakeholders the development of robust zonal demand curve improvements that can be put in place in the future."

**NEPGA 206 Request.** In response to the Informational Report and the announcement that the ISO does not intend to file sloped zonal demand curves, NEPGA filed on June 23 a request that the FERC "initiate a Section 206 proceeding on the ISO-NE Tariff and order ISO-NE to file the sloped zonal demand curves developed by ISO-NE and NEPOOL stakeholders, and proposed by ISO-NE as recently as April 2015 ("Zonal Curves"), for effect in FCA 10, amended to eliminate an FCA clearing rule ISO-NE had proposed as part of its Zonal Curves design." NEPGA asked that the ISO be compelled to make that filing within 30 days of that FERC order. The ISO answered and opposed NEPGA's request on July 2. Comments supporting the NEPGA request were filed by EPSA on July 7. NEPOOL submitted comments on July 8 (taking no position on whether an order to implement sloped zonal demand curves generally is appropriate or justified, or whether implementation can be achieved in time for FCA-10, but if such an order were to be issued, urging that any Market Rule changes be fully discussed, and voted by NEPOOL pursuant to a schedule that allows the NEPOOL stakeholder process to proceed to completion and account for the many interrelated issues associated with such Market Rule changes. NEPOOL urged the FERC to reject the NEPGA request that the FERC order a specific solution that NEPOOL voted and did not support). NEPGA's motion remains pending before the FERC.

If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

- **Jump Ball Filing: FCM Performance Incentives (ER14-1050)**

Rehearing of the *FCM PI Order* remains pending. As previously reported, the ISO and NEPOOL submitted on January 17, 2014, two alternative versions of Market Rule changes intended to improve the operating performance of capacity resources in New England -- the "ISO-NE Proposal" and the "NEPOOL

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<sup>51</sup> *ISO New England Inc. and New England Power Pool Participants Comm.*, 147 FERC ¶ 61,173 (May 30, 2014) ("*Demand Curve Order*"), *reh'g denied but clarif. granted*, 150 FERC ¶ 61,065 (Jan. 30, 2015).

<sup>52</sup> *ISO New England Inc. and New England Power Pool Participants Comm.*, 150 FERC ¶ 61,065, at P 27 (Jan. 30, 2015) ("*Demand Curve Clarification Order*").

<sup>53</sup> The changes become effective with FCA-10, and will not apply to the resources in FCA9, totaling 12.96 MW, that utilize both the renewable resource exemption and the price lock-in election.

Proposal”. As explained above, on May 30, 2014, the FERC issued an order in response to the jump ball filing.<sup>54</sup> The FERC concluded that the existing Tariff, specifically the current FCM payment design, “is unjust and unreasonable, because it fails to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits” and instituted a proceeding under Section 206 of the FPA (*see* EL14-52 in Section I above). Concluding that neither the ISO-NE Proposal nor the NEPOOL Proposal, standing alone, had been shown to be just and reasonable, the FERC, drawing features from each Proposal, went on to direct the ISO to submit by July 14, 2014 Tariff revisions reflecting a modified version of the ISO-NE Proposal and an increase in the Reserve Constraint Penalty Factors, consistent with NEPOOL’s Proposal. Specifically, the compliance filing was to include (1) changes to implement ISO-NE’s proposed two-settlement capacity market design with certain modifications, and (2) changes to increase the RCPF values for Thirty-Minute Operating Reserves to \$1,000/MWh and for Ten-Minute Non-Spinning Operating Reserves to \$1,500/MWh. The FERC established a June 9, 2014 refund effective date. Requests for clarification and/or rehearing of the *PI Order* were filed by: NEPOOL, Connecticut and Rhode Island, Dominion, MMWEC, Indicated Generators, NEPGA, NextEra, Potomac Economics, and PSEG/NRG. On July 28, 2014, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending before the FERC.

If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; [dt\\_doot@daypitney.com](mailto:dt_doot@daypitney.com)), Harold Blinderman (860-275-0357; [hblinderman@daypitney.com](mailto:hblinderman@daypitney.com)), Eric Runge (617-345-4735; [ekrunge@daypitney.com](mailto:ekrunge@daypitney.com)) or Sebastian Lombardi (860-275-0663; [slombardi@daypitney.com](mailto:slombardi@daypitney.com)).

#### IV. OATT Amendments / TOAs / Coordination Agreements

- **Order 676-H Compliance: Revisions to Schedule 24 (ER15-519)**

As previously reported, the FERC conditionally accepted the ISO’s *Order 676-H* compliance filing, effective May 15, 2015,<sup>55</sup> but denied the ISO’s request for continued waiver of Version 003 NAESB Standards and of the standards relating to Network Integration Transmission Service (“NITS”) or Service Across Multiple Transmission Systems (“SAMTS”).<sup>56</sup> The *ISO Order 676-H Compliance Order* was not challenged and is final and unappealable.

**Additional ISO Order 676-H Compliance Filing.** On July 20, the ISO filed revisions to Schedule 24 of the OATT to comply with the *ISO Order 676-H Compliance Order* (incorporating by reference all of the Version 003 NAESB standards, and excluding no standard). Those revisions were reviewed and unanimously recommended for Participants Committee support by the Transmission Committee on July 14. The compliance changes are scheduled for Participants Committee action via the August 7, 2015 Consent Agenda (Item No. 12). Comments on the July 30 compliance filing are due on or before August 10, 2015. If you have any comments or concerns, please contact Eric Runge (617-345-4735; [ekrunge@daypitney.com](mailto:ekrunge@daypitney.com)) or Kristin Sullivan (617-345-4657; [kmsullivan@daypitney.com](mailto:kmsullivan@daypitney.com)).

- **Order 676-H Compliance: PTOs, SSPs, CSC et al. (ER15-517)**

The FERC also conditionally accepted on May 19, 2015, the TOs’<sup>57</sup> *Order 676-H* compliance filing.<sup>58</sup> As previously reported, the *TOs Order 676-H Compliance Order* denied requested waivers of certain transmission

<sup>54</sup> *See PI Order.*

<sup>55</sup> *ISO New England Inc.*, 151 FERC ¶ 61,155 (May 19, 2015) (“*ISO Order 676-H Compliance Order*”).

<sup>56</sup> If, however, the ISO continues to believe that renewed waiver of specific standards is warranted, it may file a subsequent request for a waiver detailing the circumstances that it believes warrant a waiver. *Id.* at n. 20.

<sup>57</sup> For purposes of this proceeding, the “TOs” are the Participating Transmission Owners (“PTOs”), the Schedule 20A Service Providers (“SSPs”), Cross-Sound Cable Company, LLC (“CSC”), New England Power Company (“NGrid”), Northeast Utilities Service Company (“NUSCO”), Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, and the ISO.

provider standards, dismissed requested waivers of reliability coordinator and balancing authority standards as unnecessary. In denying the Filing Parties' requests for waiver of WEQ-000, WEQ-001, WEQ-002, WEQ-003, WEQ-004, WEQ-008, WEQ-011-1.2, WEQ-011-1.3, and WEQ-011-1.6, the FERC stated that the "Filing Parties are transmission providers, so the standards apply to them, and they are required to implement the standards once they perform the relevant business practices (even if they currently do not perform those practices)."<sup>59</sup> The May 19 order was not challenged and is final and unappealable.

**Additional TOs Order 676-H Compliance Filing.** On July 20, the TOs filed Tariff revisions to incorporate the complete set of Version 003 Business Practice Standards into their tariffs without modification and to remove references to waiver requests previously sought of the Version 003 NAESB standards. Changes were filed to OATT Schedules 18, 20A Common, Schedule 20A-NU, 21 Common, 21-FGE, 21-UES, 21-NEP, and 21-NU. Comments on the July 20 compliance filing are due on or before August 6, 2015. If you have any comments or concerns, please contact please contact Eric Runge (617-345-4735; [ekrunge@daypitney.com](mailto:ekrunge@daypitney.com)) or Kristin Sullivan (617-345-4657; [kmsullivan@daypitney.com](mailto:kmsullivan@daypitney.com)).

- **Order 1000 Interregional Compliance Filings (ER13-1960; ER13-1957)**

As previously reported, the FERC conditionally accepted, subject to compliance filings due July 14, revisions to the ISO Tariff to comply with the interregional coordination and cost allocation requirements of *Orders 1000* and *1000-A* and (ii) an Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol ("Protocol").<sup>60</sup> The *Order 1000 Interregional Compliance Changes* included (i) revisions to Attachment K to add provisions describing the interregional coordination provisions included in the Amended Protocol, as well as adding other provisions facilitating the consideration of interregional solutions to regional needs; (ii) a new Schedule 15 reflecting the methodology for allocation among ISO-NE and NYISO of the costs of approved interregional transmission projects; (iii) revisions to Schedule 12 describing the regional cost allocation within New England of the costs of approved interregional transmission projects; and (iv) conforming changes to Tariff Section I.

**Second Order 1000 Interregional Compliance Changes.** On July 13, the ISO filed revisions to the ISO-NE Tariff and to the Protocol in response to the *Order 1000 Interregional Compliance Filing Order* ("Second Order 1000 Interregional Compliance Changes"). The Second *Order 1000 Interregional Compliance Changes* were supported by the Participants Committee at the June 25 session of the Summer Meeting. On August 3, NEPOOL filed comments summarizing that support. This matter is pending before the FERC. If you have any comments or concerns, please contact Eric Runge (617-345-4735; [ekrunge@daypitney.com](mailto:ekrunge@daypitney.com)).

- **Order 1000 Compliance Filing (ER13-193; ER13-196)**

As previously noticed, the FERC issued, on March 19, 2015, its Order on Rehearing and Compliance<sup>61</sup> of the region's *Order 1000* compliance filing.<sup>62</sup> A memo summarizing the 200-page order in more detail was circulated by NEPOOL Counsel on March 23 and posted on the NEPOOL website Litigation Report Updates page.

**ISO Request for Clarification and/or Rehearing.** On April 20, the ISO requested clarification and/or re-hearing of the *Order 1000 Compliance Rehearing Order*. Specifically, the ISO requested clarification (i)

<sup>58</sup> *Participating Transmission Owners Admin. Comm.*, 151 FERC ¶ 61,154 (May 19, 2015) ("*TOs Order 676-H Compliance Order*").

<sup>59</sup> *Id.* at P 32.

<sup>60</sup> *ISO New England Inc.*, 151 FERC ¶ 61,133 (May 14, 2015) ("*Order 1000 Interregional Compliance Filing Order*").

<sup>61</sup> *ISO New England Inc.*, 150 FERC ¶ 61,209 (Mar. 19, 2015) ("*Order 1000 Compliance Rehearing Order*"), *clarif. and/or reh'g requested*.

<sup>62</sup> *ISO New England Inc.*, 143 FERC ¶ 61,150 (May 17, 2013) ("*Order 1000 Compliance Order*"), *order on reh'g* 150 FERC ¶ 61,209 (Mar. 19, 2015).

that the FERC's concerns with the non-discriminatory applicability of the "hold harmless" clause contained in the Non-Incumbent Transmission Developer Operating Agreement ("NTDOA") could be addressed by the inclusion of a similar clause in the Transmission Operating Agreement ("TOA"); and (ii) that no changes are required to comply with Regional Cost Allocation Principle 4 and that language providing that "the costs of any external impacts of New England regional projects will not be borne by New England customers" need not be removed from Schedule 15 of the OATT. On May 4, the TOs submitted comments supporting the ISO's request. On May 15, the FERC issued a tolling order affording it additional time to consider the ISO's request for rehearing, which remains pending before the FERC.

**3rd Regional Order 1000 Compliance Filing.** On May 18, the ISO and PTO AC jointly submitted revisions to Sections I and II of the ISO Tariff (-005) and to the TOA (-004) to comply with the Mar 19 order on the 2nd Regional *Order 1000* compliance filing. The compliance materials, which were not ready in time for NEPOOL consideration before the May 18 filing deadline, were considered and unanimously supported at the June 5 Participants Committee meeting. On June 5, the Participants Committee filed comments supporting the filing. On June 8, LS Power filed a protest, requesting that the FERC require the ISO to revise Attachment K Section 4.3(k) and the definition of Backstop Transmission Solution as described in its protest. The ISO answered the LS Power protest on June 18. LS Power answered the IO answer on June 26. The 3rd regional *Order 1000* compliance filing remains pending before the FERC.

If you have any comments or concerns, please contact Eric Runge (617-345-4735; [ekrunge@daypitney.com](mailto:ekrunge@daypitney.com)).

## V. Financial Assurance/Billing Policy Amendments

*No Activity to Report*

## VI. Schedule 20/21/22/23 Changes

- **Schedule 23: Green Mountain Power SGIA (ER15-2289)**

On July 28, the ISO and Green Mountain Power ("GMP") filed a non-conforming SGIA between the ISO and GMP, as both the Interconnection Customer and the Interconnecting Transmission Owner. The SGIA is non-conforming in that it contains certain deviations from Schedule 23's *pro forma* SGIA that accommodate GMP's status as both the Interconnection Customer and the Interconnecting Transmission Owner. A June 22, 2015 effective date was requested. Comments on this filing are due on or before August 18. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **Schedule 21-NEP: Mass Elec/Paxton Facilities Coord. & Backup Service Agreement (ER15-1838)**

On July 15, the FERC accepted an amended Facilities Coordination and Backup Service Agreement Massachusetts Electric Company ("MECO") and Paxton Municipal Light Department ("PMLD"). The Agreement sets forth the terms under which MECO and PMLD maintain mutual backup distribution service for their interconnected distribution facilities. National Grid will provide this service over distribution facilities owned by its affiliate MECO in the event that service to either of the existing primary service delivery points is interrupted. The Agreement was accepted with an April 1, 2015 effective date, as requested. Unless the July 15 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **Schedule 21-UI: Pootatuck Project Non-Pool Supported Cost Recovery (ER15-1808)**

On July 1, the FERC accepted revisions to Section III.2 of Schedule 21-UI to include the Pootatuck Project in UI's list of transmission projects that include Localized Facilities. The revisions permit UI to recover the portion of the costs of the Pootatuck Project that the ISO determined are not Pool-Supported PTF Costs under Schedule 12C of the ISO OATT. The July 1 order was not challenged, is final and unappealable, and this

proceeding is concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **Opinion 531-A Compliance Filing: CTMEEC (ER15-584)**

On December 5, 2014, the ISO submitted on behalf of the Connecticut Transmission Municipal Electric Energy Cooperative (“CTMEEC”) changes to Attachment B to Schedule-21 CTMEEC to conform Schedule-21 CTMEEC to the holdings in *Opinions 531* and *531-A*. Comments, if any, on this filing were due on or before December 26; none were filed and this matter remains pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **LGIA – NU/CPV Towantic (ER15-200)**

On August 4, the FERC approved the uncontested settlement agreement resolving all issues related to the unexecuted but accepted<sup>63</sup> LGIA (LGIA-ISONE/NU-14-02) between CPV Towantic, Eversource and the ISO, governing the interconnection of CPV Towantic’s 795 MW natural gas-fired plant located in Oxford, Connecticut.<sup>64</sup> Unless the Settlement Agreement Order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **Schedule 21-FG&E Annual Informational Filing (ER09-1498)**

On June 25, 2015, Fitchburg Gas & Electric (“FG&E”) submitted its data and schedules used to calculate its annual transmission revenue requirement for Non-PTF Local Network Transmission Service, Firm Point-to-Point Transmission Service and Non-Firm Point-to-Point Transmission Service as set forth in Schedule 21-FG&E covering the June 1, 2015 – May 31, 2016 period. FG&E reported that its annual revenue requirement reflected in FG&E’s rates effective June 1, 2015 is \$1,452,318, a roughly 22% increase over the previous rate. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **Schedule 21-NSTAR Annual Informational Filing (ER09-1243; ER07-549)**

On June 1, 2015, NSTAR submitted an informational filing containing the true-up of billings under Schedule 21-NSTAR for the period January 1, 2014 through December 31, 2014. NSTAR stated that the filing complies with the requirements of Section 4 and Attachment D of Schedule 21-NSTAR, as well as the Settlement Agreement previously approved by the FERC.<sup>65</sup> On June 30, 2015, NSTAR supplemented its June 1 annual informational filing with a “CWIP Supplement” in accordance with Section 4.1(i) and (ix) of Schedule 21-NSTAR as added and supplemented by Article 4.2 of the 2008 Settlement. The CWIP Supplement was provided primarily on a project-specific basis, and included NSTAR’s 2015 long-range construction forecast. The FERC will not notice these filings for public comment, and absent further activity, no further FERC action is expected. No comments have been filed on either of these informational filings. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **Schedule 21-CMP Annual Informational Filing (ER09-938)**

On June 30, CMP submitted its annual update to the formula rates contained in Schedule 21-CMP. CMP indicated that the informational filing reflected actual cost data for the 2014 calendar year plus estimated cost data for the 2015 calendar year associated with CMP’s forecasted transmission plant additions and MPRP CWIP as well as the annual true-up and associated interest. CMP referred to Section 10.2 of Schedule 21-CMP for specific procedures for review and challenges to the informational report. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

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<sup>63</sup> *ISO New England Inc. and Northeast Utilities Service Co.*, 149 FERC ¶ 61,274 (Dec. 24, 2014).

<sup>64</sup> *ISO New England Inc. and Northeast Utilities Service Co.*, 152 FERC ¶ 61,109 (Aug. 4, 2015) (“*Settlement Agreement Order*”).

<sup>65</sup> *See NSTAR Elec. Co.*, 123 FERC ¶ 61,270 at P 5 (2008).

<b>VII. NEPOOL Agreement/Participants Agreement Amendments</b>
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*No Activity to Report*

<b>VIII. Regional Reports</b>
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- **Opinion 531-A Refund Report: FG&E (EL11-66)**

On June 29, 2015, FG&E filed its refund report for its customers taking local service during the refund period in accordance with *Opinion 531-A*. Comments, if any, on this filing were due on or before July 20; none were filed and this matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **Capital Projects Report - 2015 Q1 (ER15-1710)**

The FERC accepted on June 26 the ISO's Capital Projects Report and Unamortized Cost Schedule covering the first quarter ("Q1") of calendar year 2015 (the "Report"). As previously reported, highlights from the Q1 Report included the following new projects: (i) Business Continuity Plan (BCP) Infrastructure Enhancements Phase III – Markets Infrastructure (\$2.52 million); (ii) Lawson Financial Platform Upgrade (\$495,200); and (iii) NERC Reliability Standard MOD-25 Generator Dynamics Data Management (\$309,700). Projects reported to have had a significant change are: (i) Generation Control Application (GCA) Production Part 1 (\$1.84 million increase); Voltage Stability (\$917,200 increase -- additional requirements and scope; implementation delayed to December 2015); CTS (\$1.516 million decrease – implementation delay permitted work to be shifted to internal ISO-NE resources); GCA Production Part 2 (\$1.5 million decrease – implementation deferred beyond 2015, funds returned to Emerging Work Fund); 3d Party FTR Administration (\$1.455 decrease – regulatory and jurisdictional delays pushing majority of work into 2016); and Divisional Accounting (\$496,800 decrease -- implementation delayed to 2016). The June 26 order was not challenged and is final and unappealable. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; [pnbelval@daypitney.com](mailto:pnbelval@daypitney.com)) or Kristin Sullivan (617-345-4657; [kmsullivan@daypitney.com](mailto:kmsullivan@daypitney.com)).

- **LFTR Implementation: 27<sup>th</sup> Quarterly Status Report (ER07-476; RM06-08)**

The ISO filed the twenty-seventh of its Quarterly Status Reports regarding LFTR implementation on July 15. As noted in the business priorities discussions, the ISO reported that it expects to file its proposal (following completion of the Participant Processes) in the first half of 2016. Third party clearing design could then be implemented during Q4 2016 for the 2017 annual FTR auction, about six months later (mid-2017) for monthly auctions, and during Q4 2018 for an initial auction of LFTRs. The estimated 18-month LFTR implementation process, described in previous reports, would be initiated in 2016, presuming the third party clearing design is accepted and related FAP changes resolved. These status reports are not noticed for public comment and no comments have been filed.

- **IMM Quarterly Markets Reports - 2015 Q1 (ZZ15-4)**

On June 9, 2015, the Internal Market Monitor ("IMM") filed with the FERC its report for the first quarter of 2015 of "market data regularly collected by [it] in the course of carrying out its functions under ... Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. A summary of this report will be presented at the Participants Committee's August 7 meeting.

- **IMM 2014 Annual Markets Report (ZZ15-4)**

On May 20, the ISO's IMM filed its 2014 Annual Markets Report, which covers the period from January 1, 2014 to December 31, 2014. The report addresses the development, operation, and performance of the New England Markets and presents an assessment of each market based on market data, performance criteria, and independent studies, providing the information required under Section 17.2.4 of Appendix A to Market Rule 1. On the basis of its review of market outcomes and related information, the IMM concluded, as it has for several years in a row, that the New England Market operated competitively in 2014, with market

concentration low, and energy prices at levels consistent with the short-run marginal cost of production. The IMM reported that, despite milder weather in 2014, energy prices increased from 2013 to 2014, driven primarily by significant increases in fuel prices in the first quarter of 2014. Other highlights included:

- ▶ Total costs increased 12% The increase in costs resulted from an increases in natural gas prices, operating reserve requirements, NCPC (particularly during Q1), and regulation service payments.
- ▶ Reductions in generation availability associated with the availability of natural gas declined in 2014.
- ▶ Increased reliability during 2014 and lower energy prices following Q1 2014 attributed to a combination of market fundamentals (e.g. increased LNG supply in late 2014, lower oil prices, a mild summer) and market rule changes.
- ▶ Real-Time Operating Reserve payments declined to \$38.6 million in 2014 from \$54.0 million in 2013.
- ▶ Payments to resources providing regulation service totaled \$28.8 million in 2014, a 41% increase from 2013. Order 755-related changes to the methodology for calculating regulation service payments, and increased natural gas prices, contributed to the increased cost of regulation service.
- ▶ The IMM conclusion that the 1.75 ratio (of a generator's higher-priced to lower-price fuel index), used to determine when dual-fuel generators should be exempt from the requirement to justify and verify the use of the higher-priced fuel, continues to be a reasonable and appropriate indicator of oil and natural gas price convergence and consequently should remain as the exemption threshold.

The IMM renewed its recommendation that the Market Rules should be revised so that Real-Time NCPC charges do not prevent virtual transactions from improving the liquidity in the Day-Ahead Energy Market. This recommendation and other report highlights will be discussed in more detail at the Participants Committee's August 7 meeting.

## IX. Membership Filings

- **August 2015 Membership Filing (ER15-2339)**

On July 31, NEPOOL requested that the FERC accept the membership of AmericaWide Energy (Supplier Sector); CLEAResult Consulting (AR Sector, DG Sub-Sector); Guzman Energy (Supplier Sector); and Harborside Energy of Massachusetts (Supplier Sector). Comments on this filing are due on or before August 21, 2015.

- **July 2015 Membership Filing (ER15-2088)**

On June 30, NEPOOL requested that the FERC accept (i) the membership of Bucksport Generation; Bath Iron Works and Longreach Energy; and Interstate Gas Supply; and (ii) the termination of the Participant status of Great Bay Energy IV, LaBree's Inc. and Labree's Energy, and Solios Power. The FERC accepted the memberships and terminations on July 29, 2015.

- **June 23, 2015 Membership Filing (ER15-1959)**

On July 22, the FERC accepted the membership of New England Energy Connection (Provisional Member; Wallingford Energy Related Person) and the name change of Talen Energy Marketing (f/k/a PPL EnergyPlus).

- **June 2015 Membership Filing (ER15-1807)**

On July 2, the FERC accepted the termination of the Participant status of Provisional Member New England ITC.

**X. Misc. - ERO Rules, Filings; Reliability Standards**

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **FFT Report: July 2015 (NP15-32)**

NERC submitted on July 30, 2015 its Find, Fix, Track and Report (“FFT”) informational filing for the month of July 2015. The July FFT resolves 26 possible violations of 6 Reliability Standards that posed a risk minimal risk to bulk power system (“BPS”) reliability, but which have since been remediated.<sup>66</sup> FFT filings are for information only and are not be noticed for public comment by the FERC.

- **FFT Report: June 2015 (NP15-30)**

NERC submitted on June 30, 2015 its FFT informational filing for the month of June 2015. The June FFT resolves 20 possible violations of 7 Reliability Standards that posed a risk minimal risk to BPS reliability, but which have since been remediated.

- **Revised Reliability Standards: PRC-004-5; PRC-010-2 (RD15-5)**

On June 8, 2015, NERC filed for approval changes to PRC-004-5 (Protection System Misoperation Identification and Correction) and PRC-010-2 (Under Voltage Load Shedding). The proposed Reliability Standards address misoperation of undervoltage load shedding (“UVLS”) equipment and were developed as Phase 2 of NERC’s pending proposal to consolidate UVLS Program Reliability Standards. Comments on this filing were due on or before July 9, 2015; none were filed. On July 7, NERC proposed revisions to the Violation Risk Factors (“VRF”) for Requirements R1 through R6 of PRC-004-5 (as well as for PRC-004-3 and PRC-004-5). Comments on the July 7 filing are due on or before August 7.

- **Revised Reliability Standard: CIP-014-2 (RD15-4)**

On July 14, the FERC approved CIP-014-2 (Physical Security) which, consistent with Order 802,<sup>67</sup> removes the term “widespread” from Requirement R1. CIP-014-2 became effective on the date of the order, or July 14, 2015. Unless the July 14 order is challenged, this proceeding will be concluded.

- **NOPR: Revised TOP and IRO Reliability Standards (RM15-16)**

On June 18, 2015, the FERC issued a NOPR proposing to approve changes reflected in the following Transmission Operations (“TOP”) and Interconnection Reliability Operations and Coordination (“IRO”) Reliability Standards:<sup>68</sup>

- TOP-001-3 (Transmission Operations);
- TOP-002-4 (Operations Planning);
- TOP-003-3 (Operational Reliability Data);
- IRO-001-4 (Reliability Coordination – Responsibilities);
- IRO-002-4 (Reliability Coordination –Monitoring and Analysis);
- IRO-008-2 (Reliability Coordinator Operational Analyses and Real-time Assessments);
- IRO-010-2 (Reliability Coordinator Data Specification and Collection);
- IRO-014-3 (Coordination Among Reliability Coordinators); and

<sup>66</sup> Only possible violations that pose a minimal risk to Bulk-Power System reliability are eligible for FFT treatment. See *N. Am. Elec. Reliability Corp.*, 138 FERC ¶ 61,193 (Mar. 15, 2012) at PP 46-56.

<sup>67</sup> *Physical Security Reliability Standard*, Order No. 802, 149 FERC ¶ 61,140 (Nov. 20, 2014) (“*Order 802*”), *reh’g denied*, 151 FERC ¶ 61,066 (Apr. 23, 2015).

<sup>68</sup> *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, 151 FERC ¶ 61,236 (May 14, 2015) (“*TOP/IRO NOPR*”).

▸ IRO-017-1 (Outage Coordination).

NERC indicated that the TOP/IRO Standards, which supersede the changes submitted in RM13-15, -14, and -12, but concurrently withdrawn, include improvements over the currently effective TOP and IRO Reliability Standards in key areas such as: (1) operating within SOLs and IROLs; (2) outage coordination; (3) situational awareness; (4) improved clarity and content in foundational definitions; and (5) requirements for operational reliability data. NERC requested that the TOP/IRO Changes be approved as of the first day of the first calendar quarter that is 12 months after the date that the Standards are approved, with the exception of TOP-003-3 and proposed IRO-010-2, which were requested to be approved 3 months earlier. On May 12, NERC supplemented its March 18 filing by removing Load Serving Entities (“LSEs”) from the applicability of proposed Reliability Standard TOP-001-3 in light of the FERC’s order on NERC’s Risk-Based Registration (“RBR”) initiative.<sup>69</sup> Comments on this NOPR are due on or before August 24, 2015.<sup>70</sup>

- **NOPR: Revised Reliability Standards: CIP-003-6, CIP-004-6, CIP-006-6, CIP-007-6, CIP-009-6, CIP-010-2, CIP-011-2 (RM15-14)**

On July 16, 2015, the FERC issued a NOPR proposing to approve changes to seven CIP (“Critical Infrastructure Protection”) Reliability Standards to improve the cyber security protections required by the CIP Standards and address four directives from *Order 791* (the “Supply Chain Cyber Controls Changes”).<sup>71</sup> NERC stated that the Supply Chain Cyber Controls Changes (i) remove the “identify, assess, and correct” language from the 17 requirements in the CIP Version 5 Standards that included such language; (ii) require responsible entities to implement cyber security plans for assets containing low impact BES Cyber Systems; (iii) include specific requirements applicable to transient devices to further mitigate the security risks associated with such devices; and (iv) require entities to implement security controls for non-programmable components of communication networks at Control Centers with high or medium impact BES Cyber Systems. NERC requested that the Supply Chain Cyber Controls be approved, effective on **April 1, 2016**. Comments on the *Revised CIPs NOPR* are due on or before September 21, 2015.<sup>72</sup>

- **Revised Reliability Standards: Transition to “Remedial Action Scheme”, PRC-010-1, EOP-011-1 (RM15-13, RM15-12; RM15-7)**

On June 18, the FERC issued a NOPR<sup>73</sup> proposing to approve three related NERC petitions that revise (i) the definition of “Remedial Action Scheme” and nearly 20 Reliability Standard to insert that term in place of the term “Special Protection System”, which are used interchangeably throughout the Reliability Standards (the “RAS Changes”) (RM15-13); (ii) PRC-010-1 (Undervoltage Load Shedding), a definition of “Undervoltage Load Shedding Program (UVLS Program)”, and associated VRFs and VSLs (together, the “UVLS Changes”) (RM15-12); and (iii) EOP-011-1 (Emergency Operations), a revised definition of “Energy Emergency”, and associated VRFs and VSLs (together, the “Emergency Operations Changes”) (RM15-7). Comments on this NOPR are due on or before August 24, 2015.<sup>74</sup>

- **NOPR: New Reliability Standard: TPL-007-1 (RM15-11)**

On May 14, 2015, FERC issued a NOPR proposing to approve a new Reliability Standard -- TPL-007-1 (Geomagnetic Disturbance Operations) -- and one new definition (Geomagnetic Disturbance Vulnerability

<sup>69</sup> *N. Am. Elec. Reliability Corp.*, 150 FERC ¶ 61,213 (2015) (“RBR Order”).

<sup>70</sup> The *TPL/IRO NOPR* was published in the *Fed. Reg.* on June 24, 2015 (Vol. 80, No. 121) pp. 36,280-36,293.

<sup>71</sup> *Revised Critical Infrastructure Protection Reliability Standards*, 152 FERC ¶ 61,054 (July 16, 2015) (“*Revised CIPs NOPR*”).

<sup>72</sup> The *Revised CIPs NOPR* was published in the *Fed. Reg.* on July 22, 2015 (Vol. 80, No. 140) pp. 43,354-43,367.

<sup>73</sup> Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of “Remedial Action Scheme” and Related Reliability Standards, 151 FERC ¶ 61,230 (June 18, 2015).

<sup>74</sup> The *NOPR* was published in the *Fed. Reg.* on June 24, 2015 (Vol. 80, No. 121) pp. 36,293-36,301.

Assessment), associated VRFs and VSLs (together, the “GMD Operations Changes”).<sup>75</sup> In addition, the FERC proposes to direct NERC (i) to develop modifications to the benchmark GMD event definition set forth in TPL-007-1 Attachment 1 so that the definition is not based solely on spatially-averaged data and (ii) to submit a work plan, and subsequently one or more informational filings, that address specific GMD-related research areas. As previously reported, NERC stated that the GMD Operations Changes address the FERC’s directive in *Order 779* that NERC develop a Reliability Standard that requires owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark geomagnetic disturbance events on the Bulk-Power System equipment and the Bulk-Power System as a whole.<sup>76</sup> NERC requested the FERC approve a five-year phased implementation plan for compliance with TPL-007-1. Comments on this NOPR were due on or before July 27, 2015.<sup>77</sup> Since the last Report, comments were filed by over 20 parties, including ISO-NE/NYIOS/PJM/MISO/IESO, EEI, Exelon, and NERC. This matter is pending before the FERC.

- **NOPR: Revised Reliability Standard: PRC-005-4 (RM15-9)**

On April 16, 2015, the FERC issued a NOPR proposing to approve changes to PRC-005-4 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance), one new (Sudden Pressure Relaying) and four revised definitions (Protection System Maintenance Program, Component Type, Component, and Countable Event), and the associated VRFs and VSLs (together, the “PRC-005 Changes”).<sup>78</sup> As previously reported, NERC stated that the PRC-005 Changes address FERC concerns expressed in the *Order 758* proceeding that NERC’s proposed interpretation of PRC-005-1 may not include all components that serve in some protective capacity.<sup>79</sup> NERC requested that the PRC-005 Changes be approved, effective on the first day of the first calendar quarter following FERC approval. Comments on this NOPR were due on or before June 22, 2015<sup>80</sup> and were filed by: EEI, NERC, NRECA, Southern Company Services, and TVA. This matter is pending before the FERC.

- **New Reliability Standard: PRC-026-1 (RM15-8)**

On December 31, 2014, NERC filed for approval a new Standard, PRC-026-1 (Relay Performance During Stable Power Swings) and associated VRFs and VSLs (the “PRC-026 Standard”) in response to the FERC’s directive in *Order 733*<sup>81</sup> to develop a Reliability Standard addressing undesirable relay operation due to stable power swings. NERC requested that PRC-026 be approved, effective as follows: R1 on the first day of the first full calendar year that is 12 months after FERC approval; R2-R4 on the first day of the first full calendar year that is 36 months after FERC approval. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

<sup>75</sup> *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 151 FERC ¶ 61,134 (May 14, 2015) (“*TPL-007 NOPR*”).

<sup>76</sup> *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147 (“*Order 779*”).

<sup>77</sup> The *TPL-007 NOPR* was published in the *Fed. Reg.* on May 26, 2015 (Vol. 80, No. 100) pp. 29,990-30,001.

<sup>78</sup> *Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance Reliability Standard*, 151 FERC ¶ 61,026 (Apr. 16, 2015) (“*Protection System NOPR*”).

<sup>79</sup> *Interpretation of Protection System Reliability Standard*, Notice of Proposed Rulemaking, 133 FERC ¶ 61,223 (2010) at P 11; *Interpretation of Protection System Reliability Standard*, Order No. 758, 138 FERC ¶ 61,094 (“*Order 758*”), *order on reh’g*, 139 FERC ¶ 61,227 (2012).

<sup>80</sup> The *Protection System NOPR* was published in the *Fed. Reg.* on Apr. 22, 2015 (Vol. 80, No. 77) pp. 22,444-22,449.

<sup>81</sup> *Transmission Relay Loadability Reliability Standard*, Order No. 733, 130 FERC ¶ 61,221 (2010); *order on reh’g and clarif.*, Order No. 733-A, 134 FERC ¶ 61,127 (2011); *clarified*, Order No. 733-B, 136 FERC ¶ 61,185 (2011) (“*Order 733*”).

- **NOPR: Revised Reliability Standard: PRC-002-2 (RM15-4)**

On April 16, 2015, the FERC issued a NOPR proposing to approve changes to PRC-002-2 (Disturbance Monitoring and Reporting Requirements), associated VRFs and VSLs, and the retirement of PRC-002-1 (Define Regional Disturbance Monitoring and Reporting Requirements) and PRC-018-1 (Disturbance Monitoring Equipment Installation and Data Reporting) (together, the “PRC-002 Changes”).<sup>82</sup> As previously reported, NERC stated that the PRC-002 Changes address FERC concerns expressed in *Order 693*<sup>83</sup> with the “fill in the blank” aspects in PRC-002-1 and PRC-018-1.<sup>84</sup> NERC requested that the PRC-002 Changes be approved, effective on the first day of the first calendar quarter six months following FERC approval. Comments on this NOPR were due on or before June 22, 2015<sup>85</sup> and were filed by APPA, Bonneville, and NERC. NERC submitted reply comments on July 13. This matter is pending before the FERC.

- **Order 810: Revised Reliability Standard: BAL-001-2 (RM14-10)**

Also on April 16, the FERC approved changes to BAL-001-2 (Real Power Balancing Control Performance) (“BAL-001 Changes”).<sup>86</sup> In addition, the FERC required NERC (i) to submit an informational filing addressing the impact of the proposed Reliability Standard on inadvertent interchange and unscheduled power flows and (ii) to revise the definition of Reporting ACE.<sup>87</sup> As previously reported, the BAL-001 Changes add a frequency component to the measurement of a Balancing Authority’s Area Control Error (“ACE”) and allow for the formation of “Regulation Reserve Sharing Groups.” The BAL-001 Changes will become effective June 1, 2016. On May 18, Powerex requested clarification or, in the alternative, rehearing of *Order 810*, requesting that the FERC (i) direct all Balancing Authorities in the Western Interconnection to disclose and publish their clock-minute ACE data no later than 30 days after the end of each month; and (ii) clarify that the informational filing should detail the extent to which unscheduled flows associated with BAA imbalances required curtailment of transmission schedules or other mitigation measures. On June 12, the FERC issued a tolling order affording it additional time to consider the Powerex request, which remains pending before the FERC.

- **NOPR: Revised Reliability Standard: MOD-001-2 (RM14-7)**

The MOD-001-2 NOPR remains pending before the FERC. On June 19, 2014, the FERC issued a NOPR proposing to approve changes to MOD-001-2 (Modeling, Data, and Analysis - Available Transmission System Capability) (“MOD Changes”) proposed by NERC. The MOD Changes replace, consolidate and improve upon the Existing MOD Standards in addressing the reliability issues associated with determinations of Available Transfer Capability (“ATC”) and Available Flowgate Capability (“AFC”). MOD-001-2 will replace the six Existing MOD Standards<sup>88</sup> to exclusively focus on the reliability aspects of ATC and AFC determinations. NERC requested that the revised MOD Standard be approved, and the Existing MOD Standards be retired, effective on the first day of the first calendar quarter that is 18 months after the date that the proposed Reliability Standard is approved by the FERC. NERC explained that the implementation period is intended to provide NAESB sufficient time to include in its WEQ Standards, prior to MOD-001-2’s effective date, those elements from the Existing

<sup>82</sup> *Disturbance Monitoring and Reporting Requirements Reliability Standard*, 151 FERC ¶ 61,042 (Apr. 16, 2015) (“PRC-002 NOPR”).

<sup>83</sup> *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416, FERC Stats. & Regs. ¶ 31,242, at PP 1131-1222, *order on reh’g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007) (“*Order 693*”).

<sup>84</sup> *Interpretation of Protection System Reliability Standard*, Notice of Proposed Rulemaking, 133 FERC ¶ 61,223 (2010) at P 11; *Interpretation of Protection System Reliability Standard*, Order No. 758, 138 FERC ¶ 61,094 (“*Order 758*”), *order on reh’g*, 139 FERC ¶ 61,227 (2012).

<sup>85</sup> The PRC-002 NOPR was published in the *Fed. Reg.* on Apr. 22, 2015 (Vol. 80, No. 77) pp. 22,441-22,444.

<sup>86</sup> *Real Power Balancing Control Performance Rel. Standard*, Order No. 810, 151 FERC ¶ 61,048 (“*Order 810*”), *clarification and/or reh’g requested*.

<sup>87</sup> *Id.* at P 20.

<sup>88</sup> The 6 existing MOD Standards to be replaced by MOD-001-2 are: MOD-001-1, MOD-004-1, MOD-008-1, MOD-028-2, MOD-029-1a and MOD-030-2.

MOD Standards, if any, that relate to commercial or business practices and are not included in proposed MOD-001-2. The FERC seeks comment from NAESB and others whether 18 months would provide adequate time for NAESB to develop related business practices associated with ATC calculations or whether additional time may be appropriate to better assure synchronization of the effective dates for the proposed Reliability Standard and related NAESB practices. The FERC also seeks further elaboration on specific actions NERC could take to assure synchronization of the effective dates. Comments on this NOPR were due August 25, 2014,<sup>89</sup> and were filed by NERC, Bonneville, Duke, MISO, and NAESB. On December 19, 2014, NAESB supplemented its comments with a report on its efforts to develop WEQ Business Practice Standards that will support and coordinate with the MOD Standards proposed in this proceeding. As noted above, the MOD-001-2 NOPR remains pending before the FERC.

- **NOPR: BAL-002-1a Interpretation Remand (RM13-6)**

This May 16, 2013 NOPR, which proposes to remand NERC's proposed interpretation of BAL-002 (Disturbance Control Performance Reliability Standard) filed February 12, 2013 (which would prevent Registered Entities from shedding load to avoid possible violations of BAL-002), remains pending.<sup>90</sup> NERC asserted that the proposed interpretation clarifies that BAL-002-1 is intended to be read as an integrated whole and relies in part on information in the Compliance section of the Reliability Standard. Specifically, the proposed interpretation would clarify that: (1) a Disturbance that exceeds the most severe single Contingency, regardless if it is a simultaneous Contingency or non-simultaneous multiple Contingency, would be a reportable event, but would be excluded from compliance evaluation; (2) a pre-acknowledged Reserve Sharing Group would be treated in the same manner as an individual Balancing Authority; however, in a dynamically allocated Reserve Sharing Group, exclusions are only provided on a Balancing Authority member by member basis; and (3) an excludable Disturbance was an event with a magnitude greater than the magnitude of the most severe single Contingency. The FERC, however, proposes to remand the proposed interpretation because it believes the interpretation changes the requirements of the Reliability Standard, thereby exceeding the permissible scope for interpretations. Comments on the *BAL-002-1a Interpretation Remand NOPR* were due on or before July 8, 2013,<sup>91</sup> and were filed by NERC, EEI, ISO/RTO Council, MISO, NC Balancing Area, Northwest Power Pool Balancing Authorities, NRECA, and WECC. This NOPR remains pending before the FERC.

- **Compliance Filing: BES Exclusions for Local Network Configurations (RM12-6)**

On July 1, 2015, NERC submitted, pursuant to *Order 773*, a compliance filing identifying in detail the types of local network configurations that may be excluded from the bulk electric system ("BES") following the implementation of the revised definition of the BES under Exclusion E3 of that definition. As of the date of this Report, the FERC has not noticed the compliance filing or otherwise invited public comment.

- **Removal of LSE Category from NERC Compliance Registry (RR15-4)**

On July 17, 2015, NERC filed for FERC approval the removal of the Load-Serving Entity ("LSE") functional registration category from the NERC Compliance Registry ("NCR"), as well as additional limited changes to the NERC Rules of Procedure ("ROP"). Comments on this filing are due on or before August 17, 2015.

- **Revised Regional Delegation Agreements (RR15-12)**

On June 26, NERC requested approval of revised Regional Delegation Agreements ("RDAs") with each of the eight Regional Entities, including NPCC, to be effective January 1, 2016, replacing the currently effective RDAs whose terms expire December 31, 2015. The revised RDAs will have five-year terms that automatically renew for another five-year term unless either party gives notice to terminate one year in advance of the end of the term. NERC stated that it and the Regional Entities believe the revised RDAs will enhance clarity and

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<sup>89</sup> The MOD-001-2 NOPR was published in the *Fed. Reg.* on June 26, 2014, (Vol. 79, No. 123) pp. 36,269-36,273.

<sup>90</sup> *Electric Reliability Organization Interpretation of Specific Requirements of the Disturbance Control Performance Standard*, 143 FERC ¶ 61,138 (2013) ("*BAL-002-1a Interpretation Remand NOPR*").

<sup>91</sup> The *BAL-002-1a Interpretation Remand NOPR* was published in the *Fed. Reg.* on May 23, 2013 (Vol. 78, No. 99) pp. 30,245-30,810.

consistency in the operations of the ERO, and will also provide for flexibility without diminishing NERC's oversight authority over the Regional Entities' performance of their delegated functions. Comments on the RDA revisions were due on or before Jul 27. Joint comments were submitted by APPA/TAPS, the Large Public Power Council, Public Utility District No. 1 of Snohomish County, WA, and Avista, Idaho Power, Portland General Electric, Puget Sound Energy, and the Tri-State Generation Association (with respect to the WECC Delegation Agreement. This matter is pending before the FERC.

## XI. Misc. - of Regional Interest

- **203 Application: CSC/AIA Energy (EC15-122)**

On June 1, the FERC authorized a transaction whereby Cross-Sound Cable ("CSC") will become an indirect, wholly-owned subsidiary of AIA Energy North America LLC ("AIA Energy") (and no longer a Related Person of Brookfield Energy Marketing).<sup>92</sup> CSC and AIA Energy must notify the FERC within 10 days of the date that the disposition of jurisdictional facilities has been consummated. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **203 Application: Iberdrola/CMP/ Emera (EC15-103)**

On June 2, the FERC authorized a transaction whereby UIL Holdings Corp ("UI") will become an indirect, wholly-owned subsidiary of Iberdrola, S.A (and a Related Person of Central Maine Power Company, Iberdrola Renewables, LLC, and New York State Electric & Gas Corporation).<sup>93</sup> Iberdrola and UI must notify the FERC within 10 days of the date that the disposition of jurisdictional facilities has been consummated. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **FirstEnergy PJM DR Complaint (EL14-55)**

On May 23, 2014, the same day that DC Circuit vacated *Order 745* (see Section XV below), FirstEnergy filed a complaint against PJM requesting that the FERC require the "removal of all portions of the PJM Tariff allowing or requiring PJM to include demand response as suppliers to PJM's capacity markets." FirstEnergy also requested that the results of the PJM capacity auction due to be released that same day, to the extent it included and cleared demand response resources, be considered void and legally invalid. PJM's response, and all comments and interventions were initially due on or before June 12, 2014. However, on June 11, the FERC extended that date to 30 days after the submission by FirstEnergy of an amended complaint. FirstEnergy filed its amended complaint on September 22, 2014.

Comments on the FirstEnergy Complaint were due October 22, 2014. More than 40 parties filed comments or responses to the FirstEnergy amended complaint. Many parties filed comments supporting the complaint (including Calpine, PSEG and PPL), while others opposed the complaint in its entirety (including Direct Energy and Enerwise). PJM's response argued that the complaint failed to justify the market disruption that would result from recalculating past capacity auction results, PJM was instead more focused on minimizing "litigation risk." A number of parties filed supporting comments in favor of removing demand response resources from the PJM tariff moving forward, but opposed to recalculating the results of past capacity auctions (including Exelon, the PJM IMM and NRG). Comments were also filed by National Grid and NYISO. A number of New England parties intervened, including NEPOOL (stressing that the FERC should not apply any ruling in this docket to the New England Market), Dominion, Duke Energy, Dynegy, Essential Power, Macquarie Energy, NEPGA, NESCOE, and NextEra. On November 14, FirstEnergy filed an answer to the answers, protests and comments submitted in response to its Complaint and Amended Complaint. Environmental Advocates<sup>94</sup> filed an answer to FirstEnergy's answer on November 21. Since the

<sup>92</sup> *Cross-Sound Cable Co., LLC and AIA Energy North America, LLC*, 151 FERC ¶ 62,145 (June 1, 2015).

<sup>93</sup> *Iberdrola, S.A. et al.*, 151 FERC ¶ 62,148 (June 2, 2015).

<sup>94</sup> "Environmental Advocates" are Sustainable FERC Project, Natural Resources Defense Council ("NRDC"), Sierra Club, Environmental Defense Fund, Environmental Law and Policy Center, and Acadia Center (f/k/a Environment Northeast).

last Report, CPower and Advanced Energy Management Alliance filed answers to the FirstEnergy and other answers and pleadings. On December 23, Environmental Advocates moved to lodge the US Solicitor General's application for an extension of time in which to file a petition for writ of certiorari, the Supreme Court Clerk's notice to the DC Circuit that the extension had been granted, and the DC Circuit's order extending the stay of its mandate pending the Supreme Court's final disposition of the writ of certiorari. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Jamie Blackburn ([jblackburn@daypitney.com](mailto:jblackburn@daypitney.com); 202-218-3905) or Pat Gerity ([pmgerity@daypitney.com](mailto:pmgerity@daypitney.com); 860-275-0533).

- **Study Agreement Termination: Eversource/Brookfield (ER15-2218)**

On July 16, Eversource filed a notice of termination of a Study Agreement between Eversource (PSNH) and Brookfield Power US Asset Management LLC ("Brookfield") (designated as service agreement SA-1 under PSNH's eTariff files). The Agreement compensated PSNH for the costs incurred for the now completed study of the potential upgrades to the Coos Loop that could increase the Total Transfer Capability of the Coos Loop and thereby increase the likelihood that Brookfield's Granite Wind Facility would be dispatched pursuant to Market Rule 1. Eversource requested that the termination of the Agreement be accepted for filing as of July 1, 2015, the date the Agreement expired in accordance with its terms. Comments on this filing are due on or before August 6, 2015. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **E&P Agreement MEPCO/Number Nine Wind Farm (ER15-2060)**

On June 29, MEPCO filed an Amended and Restated Second Engineering and Procurement Agreement ("E&P Agreement") between MEPCO and Number Nine Wind Farm LLC ("Number Nine") (designated as service agreement MEPCO-EP-2 under MEPCO's eTariff files). The E&P Agreement sets forth the terms and conditions under which MEPCO will provide engineering and procurement services to Number Nine in connection with Number Nine's planned 250 MW wind farm in Aroostook County, Maine. MEPCO requested that the E&P Agreement be accepted for filing as of June 29, 2015. Comments on this filing were due on or before July 20, 2015, and none were filed. This matter is pending before the FERC. If there are questions on these matters, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **EPC Agreement: Blue Sky West & Emera Maine (ER15-1459)**

As previously reported, Emera Maine filed on April 7 an executed Engineering, Procurement, and Construction Agreement ("EPC Agreement") Agreement with Blue Sky West, LLC ("Blue Sky West") to facilitate the interconnection of the Blue Sky West's 191 MW wind farm in Bingham, Mayfield Township and Kingsbury Plantation, Maine. While the Blue Sky West facility will be located in CMP's service territory, upgrades and modifications at Orrington Substation, in part owned by Emera Maine, are required and will be covered under the EPC Agreement. A March 6, 2015 effective date was requested. SunEdison filed a doc-less intervention. No comments on the EPC Agreement filing were submitted before the April 28 comment date. This matter remains pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

- **Emera MPD OATT Changes (ER15-1429)**

On April 1, Emera Maine filed changes to the Open Access Transmission Tariff ("OATT") for Maine Public District ("MPD OATT"), including to the rates, terms, and conditions set forth in MPD OATT Attachment J. Emera Maine, as successor to Maine Public Service Company ("Maine Public"), provides open access to Emera Maine's transmission facilities in northern Maine (the "MPD Transmission System") pursuant to the MPD OATT. The changes to the MPD OATT are needed to ensure that, in light of the filing by Emera of consolidated FERC Form 1 data (data comprising both the former Bangor Hydro and Maine Public systems), charges for service under the MPD OATT reflect only the costs of service over the MPD Transmission System. Emera Maine also proposed additional, limited changes to the MPD OATT. A June 1,

2015 effective date was requested. On April 9, the “Maine Customer Group”<sup>95</sup> filed a motion to reject (“Motion to Reject”) the April 1 Filing, asserting the April 1 Filing was deficient because, rather than actual rates, it included proxy rates that MPD said would be replaced with 2014 Form 1 numbers when MPD’s 2014 Form 1 was available. On April 22, the Maine PUC and the Maine Customer Group protested the filing. The MPUC challenged three aspects of the filing: (i) the proposed increase of ROE from 9.75% to 10.20% based on anomalous economic conditions; (ii) the change from a measured loss factor calculation to a fixed loss factor; and (iii) the use of end-of-year account balances, rather than average 13-month account balances, for determination of facilities that are included in rate base. In addition to those aspects, the Maine Customer Group further challenged: (iv) inclusion of an out-of-period adjustment to rate base for forecasted transmission; (v) the proposed capital structure, which they assert is artificially distorted to accommodate a requirement resulting from the merger of Emera Maine’s predecessor companies; and (vi) the proposed new cost allocation scheme. On April 24, Emera Maine answered the Maine Customer Group’s Motion to Reject. On April 29, the Maine Customer Group answered Emera Maine’s April 24 answer. On May 1, Emera Maine filed an amendment and errata to its April 1 filing, in part reflecting 2014 FERC Form 1 data rather than estimated data. On May 7, Emera Maine answered the April 22 Maine PUC and MCG protests and the MCG’s April 29 answer. On May 8, MCG moved to compel revision to Emera’s May 1 filing, asserting that it was not filed in accordance with Emera’s OATT, and specifically the Protocols for Implementing and Reviewing Charges Established by the Attachment J Rate Formulas (the “Protocols”). MCG also protested the May 1 filing on May 22. On May 26, Emera Maine answered MCG’s May 8 Motion to Compel, which MCG answered the next day. This matter remains pending before the FERC.

- **MISO Methodology to Involuntarily Allocate Costs to Entities Outside Its Control Area (ER11-1844)**

On December 18, 2012, Judge Sterner issued his 374-page initial decision which, following hearings described in previous reports, found at its core that “it is unjust, unreasonable, and unduly discriminatory to allocate costs of Phase Angle Regulating Transformers (“PARs”) of the International Transmission Company (“ITC”) to NYISO and PJM”,<sup>96</sup> which the Midwest ISO (“MISO”) and ITC proposed unilaterally to do (without the support of either PJM or NYISO) in its October 20, 2010 filing initiating this proceeding. For a summary of specific findings, please refer to any of the January to June 2013 Reports.

On January 17, 2013, ITC and MISO challenged the Initial Decision through their Brief on Exceptions. Briefs opposing exceptions were filed by the FERC Trial Staff, MISO TOs, NYISO, NY TOs, PJM, and the PJM TOs. On February 25, Joint Applicants moved to strike a portion of the PJM Brief Opposing Exceptions. On March 12, PJM answered Joint Applicants February 25 motion. MISO (now called “Midcontinent Independent System Operator, Inc.”) moved to lodge a NYISO “Broader Regional Markets Informational Report” filed March 19, 2014 in ER08-1281 and a related January 16, 2014 “Ontario-Michigan Interface PAR Performance Evaluation Report” (“Evaluation Report”) prepared by MISO, IESO and PJM. Oppositions to that motion to lodge were filed by FERC Staff, NYISO, NY TOs, PJM, and PSEG. This matter remains pending before the FERC. If there are any questions on this matter, please contact Eric Runge (617-345-4735; [ekrunge@daypitney.com](mailto:ekrunge@daypitney.com)).

- **FERC Enforcement Action: Staff Notices of Alleged Violations (IN\_\_ - \_\_)**

**Etracom/M. Rosenberg.** On July 27, 2015, the FERC issued a notice that Staff has preliminarily determined that Etracom LLC (“Etracom”) and Michael Rosenberg violated the FERC’s Anti-Manipulation Rule by engaging in manipulative virtual trading at the New Melones Intertie in the CAISO footprint during May 2011. Enforcement has preliminarily determined that Etracom’s trades were intended to artificially lower the day-ahead LMP to benefit Etracom’s congestion revenue rights positions sourced at the same location. During the period in question, Rosenberg was Etracom’s principal trader and majority owner.

<sup>95</sup> The “Maine Customer Group (“MCG”) is comprised of: the Maine Office of the Public Advocate (“MOPA”), Houlton Water Company (“Houlton”), Van Buren Light and Power District (“Van Buren”), and Eastern Maine Electric Cooperative, Inc. (“EMEC”).

<sup>96</sup> *Midwest Indep. Trans. Sys. Op., Inc.*, 141 FERC ¶ 63,021 (Dec. 18, 2012) (“*MISO Initial Decision*”) at P 923.

Recall that Notices of Alleged Violations (“NoVs”) are issued only after the subject of an enforcement investigation has either responded, or had the opportunity to respond, to a preliminary findings letter detailing Staff’s conclusions regarding the subject’s conduct.<sup>97</sup> NoVs are designed to increase the transparency of Staff’s nonpublic investigations conducted under Part 1b of its regulations. A NoV does not confer a right on third parties to intervene in the investigation or any other right with respect to the investigation.

- **FERC Enforcement Action: City Power Marketing and Tsingas (IN15-5)**

On July 2, 2015, the FERC found that City Power Marketing, LLC (“City Power”) and K. Stephen Tsingas (“Tsingas”, and together with City Power, the “City Power Respondents”) violated the FERC’s Anti-Manipulation Rules by engaging in fraudulent Up To Congestion (“UTC”) transactions in PJM’s energy markets.<sup>98</sup> City Power Respondents were jointly and severally required to disgorge unjust profits of **\$1,278,358** and to assessed **\$15 million** in civil penalties (City Power (\$14 million) and Tsingas (\$1 million)). As previously reported, Enforcement Staff alleged that (i) City Power and Tsingas violated the FERC’s Anti-Manipulation Rule by engaging in manipulative Up To Congestion trading in PJM during July 2010; and (ii) City Power violated the FERC’s market behavior rules (18 C.F.R. § 35.41 (2014)) by making false statements and omitting material information during the investigation. Given City Power Respondents’ election under section 31(d)(3)(A) of the FPA, the *City Power Mktg Penalties Order* will not be subject to rehearing. If the penalties are unpaid within 60 days, the FERC will institute a proceeding in the appropriate district court seeking an order affirming the assessment of the civil penalties. That court will have the authority to review *de novo* the law and facts involved; and will have the jurisdiction to enforce, modify, or set aside, in whole or in part, the penalty assessment. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

## XII. Misc. - Administrative & Rulemaking Proceedings

- **Price Formation in RTO/ISO Energy & Ancillary Services Markets (AD14-14)**

On June 19, 2014, the FERC initiated a proceeding to evaluate price formation issues in RTO/ISO energy and ancillary services markets. In its notice, the FERC announced a series of staff workshops to facilitate a discussion with market operators and their stakeholders on the existing market rules and operational practices related to the use of uplift payments, offer price mitigation and offer price caps, scarcity and shortage pricing, and operator actions that affect price. The first workshop, held September 8, 2014, focused on the technical, operational and market issues that give rise to uplift payments and the levels of transparency. The second workshop, held October 28, 2014, focused on the technical, operational, and market issues related to offer price mitigation and offer price caps, and scarcity and shortage pricing in energy and ancillary services markets operated by RTOs/ISOs. In advance of the second workshop, FERC staff posted two reports, one on shortage pricing in RTO/ISO markets (<http://www.ferc.gov/legal/staff-reports/2014/AD14-14-pricingrto-iso-markets.pdf>), the other on energy offer mitigation in RTO/ISO markets (<http://www.ferc.gov/legal/staff-reports/2014/AD14-14-mitigation-rto-iso-markets.pdf>). The third and final workshop, held December 9, 2014, focused on RTO/ISO operator actions that affect price. Speaker materials from each of the workshops are posted in the FERC’s eLibrary.

**Post-Technical Workshop Comments.** On January 16, 2015, the FERC invited all interested to file post-technical workshop comments on any or all of the 12 questions listed in the attachment to its January 16 Notice. More than 40 sets of comments were submitted, including by: ISO-NE, APPA, Brookfield, Calpine, Direct Energy, EEL, EPSA, Exelon, and PSEG. The FERC web page for this issue is at <http://www.ferc.gov/industries/electric/indus-act/rto/energy-price-formation.asp>.

<sup>97</sup> See *Enforcement of Statutes, Regulations, and Orders*, 129 FERC ¶ 61,247 (Dec. 17, 2009), *order on requests for reh’g and clarification*, 134 FERC ¶ 61,054 (Jan. 24, 2011).

<sup>98</sup> *City Power Mkt’g, LLC and K. Stephen Tsingas*, 152 FERC ¶ 61,012 (July 2, 2015) (“*City Power Mktg Penalties Order*”).

- **AWEA Petition for LGIA/LGIP Rulemaking (RM15-21)**

On June 19, the American Wind Energy Association (“AWEA”) petitioned the FERC to conduct a rulemaking to revise provisions of the FERC’s *pro forma* Large Generator Interconnection Procedures (“LGIP”) and *pro forma* Large Generator Interconnection Agreement (“LGIA”). AWEA states that various aspects of the LGIP and LGIA are out of date in comparison to current market conditions and do not ensure that the generation interconnection process is just, reasonable, and not unduly discriminatory or preferential. AWEA indicated that the rulemaking would address reforms to improve (i) certainty in the study and restudy process, (ii) transparency in the interconnection process, (iii) certainty of network upgrade costs, and accountability in the interconnection process. Comments in response to this petition are due on or before September 8, 2015.

- **Order 812: Revisions to Public Utility Filing Requirements (RM15-3)**

On July 16, the FERC issued *Order 812*<sup>99</sup> revising its regulation to eliminate the requirement for (i) RTOs/ISOs and EWGs to submit FERC-566 (Annual Report of a Utility’s 20 Largest Customers), (ii) for public utilities that have not made any reportable sales under FERC-566 in any of the three preceding years to submit a FERC-566, and (iii) public utilities, when submitting FERC-566, to identify individual residential customers by name and address. The Order 812 changes will become effective October 6, 2015.<sup>100</sup>

- **NOPR: Third-Party Provision of Primary Frequency Response Service (RM15-2)**

On February 19, the FERC issued a NOPR proposing to foster competition in the sale of primary frequency response service<sup>101</sup> by permitting its sale at market-based rates by sellers with market-based rate authority for energy and capacity. The FERC stated that this NOPR is an extension of its policy reforms begun with *Order 784*<sup>102</sup> and anticipates the potential interest in purchase of primary frequency response service from third-parties as a result of a new reliability standard (BAL-003-1) that requires a Balancing Authority to maintain a minimum frequency response obligation. Comments on this NOPR were due on or before April 27, 2015<sup>103</sup> and were filed by nearly 20 parties. The NOPR is pending before the FERC.

- **NOPR: MBR Authorization Refinements (RM14-14)**

On June 19, the FERC issued a NOPR proposing to revise its current standards, and to streamline certain aspects of its filing requirements, for obtaining market-based rates (“MBR”) for sales of electric energy, capacity, and ancillary services.<sup>104</sup> In addition, the FERC clarified certain standards for obtaining and retaining MBR authority. Among other changes, the FERC proposes (i) to permit sellers in RTO/ISO markets with Commission-approved market monitoring and mitigation to include a statement that they are relying on such mitigation to address any potential horizontal market power concerns in lieu of submitting the indicative screens; (ii) to permit sellers to explain that their qualified capacity is fully committed in lieu of including indicative screens in their filings in order to satisfy the FERC’s horizontal market power tests and to submit a change in status filing when there is a net increase of 100 MW or more; (iii) to relieve sellers of their obligation to file quarterly land acquisition reports and of the obligation to provide information on sites for generation capacity development in market-based rate applications and triennial updated market power analyses; (iv) to require a change in status filing if there is a 100 MW increase in cumulative nameplate capacity added in any relevant geographic market;

<sup>99</sup> *Revisions to Public Util. Filing Reqs.*, Order No. 812, 152 FERC ¶ 61,032 (July 16, 2015) (“*Order 812*”).

<sup>100</sup> *Order 812* was published in the Fed. Reg. on July 23, 2015 (Vol. 80, No. 141) pp. 43,619-43,625.

<sup>101</sup> Primary frequency response service would be a reserve product that involves dedicating capacity on a generator or other resource for autonomous, automatic, and rapid action to change its output (within seconds) to rapidly dampen large changes in frequency.

<sup>102</sup> *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Order No. 784, 78 Fed. Reg. 46,178 (July 30, 2013), FERC Stats. & Regs. ¶ 31,349, at PP 6-7 (2013), *order on clarif.*, Order No. 784-A, 146 FERC ¶ 61,114 (2014) (“*Order 784*”).

<sup>103</sup> The NOPR was published in the *Fed. Reg.* on Feb. 26, 2015 (Vol. 80, No. 38) pp. 10,426-10,432.

<sup>104</sup> *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Svcs. by Public Utils.*, 147 FERC ¶ 61,232 (June 19, 2014) (“*MBR NOPR*”).

and (v) require corporate org charts with all MBR applications and notices of change in status. Comments on this NOPR were due September 23, 2014.<sup>105</sup> Over 25 parties filed comments and Berkshire Hathaway, Barrick Mines, and EPSA filed reply comments. This NOPR is pending before the FERC.

- **Order 807: Open Access and Priority Rights on ICIF (RM14-11)**

On March 19, the FERC issued *Order 807*,<sup>106</sup> which waives the Open Access Transmission Tariff (“OATT”) requirements of 18 CFR 35.28 (2013), the Open Access Same-Time Information System (“OASIS”) requirements of Part 37 of its regulations, 18 CFR 37 (2013), and the Standards of Conduct requirements of Part 358 of its regulations, 18 CFR 358 (2013), for any public utility that is subject to such requirements solely because it owns, controls, or operates Interconnection Customer’s Interconnection Facilities (“ICIF”),<sup>107</sup> in whole or in part, and sells electric energy from its Generating Facility. *Order 807* also finds that those seeking interconnection and transmission service over ICIF that are subject to the blanket waiver adopted in *Order 807* may follow procedures applicable to requests for interconnection and transmission service under sections 210, 211, and 212 of the FPA, which also allows the contractual flexibility for entities to reach mutually agreeable access solutions. *Order 807* establishes a modified rebuttable presumption for a 5-year safe harbor period to reduce risks to ICIF owners eligible for the blanket waiver during the critical early years of their projects. Finally, *Order 807* modifies several elements of the NOPR, including the entities eligible for the OATT waiver, the date on which the safe harbor begins, the rebuttable presumption that the ICIF owner should not be required to expand its facilities during the safe harbor, and the facilities covered by *Order 807*. *Order 807* will become effective June 30, 2015.<sup>108</sup> Requests for rehearing and/or clarification of *Order 807* were filed on April 20 by APPA/TAPS and NRECA. On May 15, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending before the FERC.

- **WIRES Request for Policy Statement on ROE for Electric Transmission (RM13-18)**

On June 26, 2013, WIRES<sup>109</sup> petitioned the FERC to institute an expedited generic proceeding and to provide such policy and clarifications as necessary to provide “greater stability and predictability regarding regulated rates of return on equity for existing and future investments in high voltage electric transmission infrastructure.” Specifically, WIRES recommended a new policy that (1) standardizes selection of proxy groups; (2) denies complainants a hearing on rates of return for existing facilities unless it is shown that existing returns are at the extremes of the zone of reasonableness; (3) allows consideration of competing infrastructure investments of other industries; (4) permits use of other rate of return methodologies; and (5) supports use of more forward-looking data and modeling. In addition, WIRES urged the FERC to support consideration of a project’s actual and anticipated benefits when a complaint is filed against the ROE for an existing project. Although the WIRES petition has not been noticed for public comments, more than 16 sets of comments have been filed. On October 3, 2013, WIRES submitted a summary of the comments and analysis filed to that point in the proceeding. On October 16, the Organization of PJM States noted its position that the WIRES petition did not present a compelling reason for the FERC to initiate a generic rulemaking proceeding or abandon its Discounted Cash Flow methodology. On November 5, 2013, a letter from US Senator Angus King, urging the FERC to establish a more certain regulatory environment that provide investors the level of confidence necessary to support and encourage needed infrastructure investments, was posted in eLibrary. This matter is pending before the FERC.

<sup>105</sup> The *MBR NOPR* was published in the *Fed. Reg.* on July 25, 2014 (Vol. 79, No. 143) pp. 43,536-43,572.

<sup>106</sup> *Open Access and Priority Rights on Interconnection Customer’s Interconnection Facilities*, Order No. 807, 150 FERC ¶ 61,211 (Mar. 19, 2015) (“*Order 807*”), *reh’g requested*.

<sup>107</sup> ICIF is the term used by the FERC in the NOPR to refer to “generator tie lines”.

<sup>108</sup> *Order 807* was published in the *Fed. Reg.* on Apr. 1, 2015 (Vol. 80, No. 62) pp. 17,654-17,682.

<sup>109</sup> WIRES, the Working group for Investment in Reliable and Economic Electric Systems, describes itself as a national non-profit association of investor-, member-, and publicly-owned entities dedicated to promoting investment in a strong, well-planned, and environmentally beneficial high voltage electric transmission grid. Information about its principles and members is available on its website [www.wiresgroup.com](http://www.wiresgroup.com).

- **Order 771: Availability of e-Tag Information to FERC Staff (RM11-12)**

Rehearing of portions of *Order 771* has been requested and remains pending. As previously reported, *Order 771*,<sup>110</sup> issued December 20, 2012, granted the FERC access, on a non-public and ongoing basis, to the complete electronic tags (“e-Tags”) used to schedule the transmission of electric power interchange transactions in wholesale markets. *Order 771* requires e-Tag Authors (through their Agent Service) and Balancing Authorities (through their Authority Service) to take steps to ensure FERC access to the e-Tags covered by this Rule by designating the FERC as an addressee on the e-Tags. The FERC stated that the information made available under this Final Rule will bolster its market surveillance and analysis efforts by helping it detect and prevent market manipulation and anti-competitive behavior. In addition, *Order 771* requires e-Tag information be made available to RTO/ISOs and their Market Monitoring Units, upon request to e-Tag Authors and Authority Services, subject to appropriate confidentiality restrictions. *Order 771* became effective February 26, 2013.<sup>111</sup> In response to requests for clarification and/or rehearing of *Order 771* filed by EEI/NRECA, Open Access Technology International, Inc., NRECA (separately), and Southern Companies (collectively, the “Rehearing Requests”), the FERC issued, on March 8, 2013, *Order 771-A*.<sup>112</sup> *Order 771-A* addressed only those issues that needed to be answered on an expedited basis to allow affected entities to comply with the requirement to ensure FERC access in a timely manner to the e-Tags covered by *Order 771*.<sup>113</sup> The FERC noted that it would issue an additional rehearing order, addressing the remaining issues raised on rehearing and clarification, which therefore remain pending before the FERC.

### XIII. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; [jfagan@daypitney.com](mailto:jfagan@daypitney.com)), Jennifer Galiette (860-275-0338; [jgaliette@daypitney.com](mailto:jgaliette@daypitney.com)) or Jamie Blackburn (202-218-3905; [jblackburn@daypitney.com](mailto:jblackburn@daypitney.com)).

- **Inquiry Into Natural Gas Trading, and Proposal to Establish an Electronic Information and Trading Platform (AD14-19)**

On September 18, 2014, Commissioner Moeller convened a meeting to discuss issues related to how transactions are conducted on the natural gas system and potential transactional improvements to address the needs of electric generators for natural gas. The meeting included representatives/speakers from various sectors of the natural gas and electric industries (load, suppliers, marketers, exchanges, gas associations, and ISOs) and environmental interests. Representatives from NYISO and PJM were among the speakers on the electric side (ISO-NE was not present). A summary of that meeting is posted on the Litigation Updates & Reports webpage ([http://nepool.com/uploads/Lit\\_Supp\\_AD14-19\\_20140918\\_Mtg\\_Summary.pdf](http://nepool.com/uploads/Lit_Supp_AD14-19_20140918_Mtg_Summary.pdf)). Written comments on issues discussed at the meeting, limited to 5 pages, were due on or before October 1, 2014. Comments were filed by more than 30 parties. There was no published activity in this proceeding since the last Report.

<sup>110</sup> *Availability of E-Tag Info. to Comm’n Staff*, Order No. 771, 141 FERC ¶ 61,235 (Dec. 20, 2012) (“*Order 771*”), *order on reh’g and clarif.*, 142 FERC ¶ 61,181 (2013).

<sup>111</sup> *Order 771* was published in the *Fed. Reg.* on Dec. 28, 2012 (Vol. 77, No. 249) pp. 76,367-76,380.

<sup>112</sup> *Availability of E-Tag Info. to Comm’n Staff*, Order No. 771-A, 142 FERC ¶ 61,181 (Mar. 8, 2013) (“*Order 771-A*”).

<sup>113</sup> *Order 771-A* clarified that: (1) Balancing Authorities and their Authority Services will have until 60 days after publication of this order to implement the validation requirements of *Order 771*; (2) validation of e-Tags means that the Sink Balancing Authority, through its Authority Service, must reject any e-Tags that do not correctly include the FERC in the CC field; (3) the requirement for the FERC to be included in the CC field on the e-Tags applies only to e-Tags created on or after March 15, 2013; (4) the FERC will deem all e-Tag information made available to the FERC pursuant to *Order 771* as being submitted pursuant to a request for privileged and confidential treatment under 18 CFR 388.112; (5) the FERC is to be afforded access to the Intra-Balancing Authority e-Tags in the same manner as interchange e-Tags; and (6) the requirement on Balancing Authorities to ensure FERC access to e-Tags pertains to the Sink Balancing Authority and no other Balancing Authorities that may be listed on an e-Tag.

- **Order 809: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (RM14-2)**

On April 16, the FERC issued *Order 809*,<sup>114</sup> which changes the nationwide Timely Nomination Cycle nomination deadline for scheduling natural gas transportation from 11:30 a.m. Central Clock Time (CCT) to 1:00 p.m. CCT and revises the intraday nomination timeline, to include adding an additional intraday scheduling opportunity during the gas operating day (Gas Day). *Order 809* also modifies the scheduling practices used by interstate pipelines to schedule natural gas transportation service and provides additional contracting flexibility to firm natural gas transportation customers through the use of multi-party transportation contracts. *Order 809* DOES NOT change the start time of the nationwide natural Gas Day (which remains 9:00 a.m. CCT), as had been proposed in the underlying NOPR.<sup>115</sup> *Order 809* established an implementation date of April 1, 2016. On July 23, in response to *Order 809*, ISO-NE described why changes to the time at which the results of the Day-Ahead Energy Market and RAA process are posted are not necessary in response to the FERC's rule making. Comments on the ISO's filing are due on or before August 18, 2015<sup>116</sup> (the ISO's response was filed in EL14-23; see Section I above).

Requests for rehearing and/or clarification of *Order 809* were filed by Desert Southwest Pipeline Stakeholders and the American Gas Association. On May 19, the Natural Gas Council asked the FERC to defer NAESB consideration of confirmation process improvements until "after the two industries have had sufficient time to implement and operate reliably under both the new gas scheduling timeline and changes to RTO/ISO dispatch schedules to conform with the newly-approved gas scheduling timeline." On May 28, 2015 the American Gas Association, the American Public Gas Association, and the Interstate Natural Gas Association of America filed a request for the Commission to clarify the manner in which all pipelines should implement the standards on April 1, 2016, and a request for clarification relating to interpretations of recall rights under existing capacity release contracts in light of the transition from two to three intraday nomination cycles.

On July 31, 2015, the FERC issued an Order on Request for Clarification and Notice of Comment Procedures.<sup>117</sup> The FERC explained that the new day-ahead nomination timelines will apply as of March 31, 2016 for those nominations that will become effective April 1, 2016. Furthermore, with respect to capacity releases, the new biddable release schedule will start at 9:00 a.m. CCT on March 31, 2016, for all releases with contracts to be effective on March 31, 2016, April 1, 2016, or thereafter. Non-biddable releases effective on March 31, 2016 will follow the existing posting schedule for the Intraday 1 and Intraday 2 Nomination Cycles, and will follow the new day-ahead nomination schedule for the Timely and Evening Nomination Cycles.

- **Posting of Offers to Purchase Capacity (Section 5 Proceeding) (RP14-442)**

Similar to the ISO/RTO 206 Order in EL14-22 et al. (see Section I above), the FERC also instituted a proceeding under Section 5 of the Natural Gas Act to examine whether interstate natural gas pipelines are providing notice of offers to purchase released pipeline capacity in accordance with section 284.8(d) of the Commission's regulations.<sup>118</sup> On or before May 19, natural gas pipelines were required to either revise their respective tariffs to provide for the posting of offers to purchase released capacity, or otherwise demonstrate that they are in full compliance with FERC regulations.<sup>119</sup> The FERC also requested that NAESB develop business practice and communication standards specifying: (1) the information required for requests to acquire capacity; (2) the methods by which such information is to be exchanged; and (3) the location of the information on a

<sup>114</sup> *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, Order No. 809, 150 FERC ¶ 61,049 (Apr. 16, 2015) ("*Order 809*").

<sup>115</sup> *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 146 FERC ¶ 61,201 (Mar. 20, 2014).

<sup>116</sup> *Order 809* was published in the *Fed. Reg.* on Apr. 24, 2015 (Vol. 80, No. 79) pp. 23,198-23,227.

<sup>117</sup> *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 152 FERC ¶ 61,095 (July 31, 2015).

<sup>118</sup> *Posting of Offers to Purchase Capacity*, 146 FERC ¶ 61,203 (Mar. 20, 2014).

<sup>119</sup> *Id.* at P 6.

pipeline's website. The Show Cause Order required each pipeline to explain in its compliance filing how it will fully comply with section 284.8(d) until NAESB develops, and the FERC implements, the requested standards, including how the pipeline will provide shippers the ability to post offers to purchase capacity on the Informational Posting section of its Internet website.

In total, the FERC received, and addressed in one omnibus order, 157 compliance filings.<sup>120</sup> Of the 157 filings, 64 pipelines revised their respective tariffs to provide for the posting of offers to purchase released capacity in a manner that complies with section 284.8(d), and 23 pipelines demonstrated that their tariffs already comply with that section. The FERC found that, and identified in its omnibus order on the compliance filings the, 69 compliance filings that did not appear to be in full compliance with that section, and directed further compliance filings from those companies as described in the omnibus order.

- **Natural Gas-Related Enforcement Actions**

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines. Since the last Report, there was one order approving a stipulation and consent agreement, preceded by a Staff notice of alleged violation, related to a violation of a gas pipeline's tariff.

**Columbia Gas Transmission, LLC (IN15-7).** On July 20, the FERC approved a Stipulation and Consent Agreement between the Office of Enforcement ("Enforcement") and Columbia Gas Transmission, LLC ("Columbia Gas").<sup>121</sup> The *Columbia Gas Order* requires Columbia Gas to pay **\$350,000 in civil penalties** as a result of violating Part 4 of its tariff by failing to post the notices of the auctions of its available firm capacity on the public side of its electronic bulletin board between January 1, 2010 and May 1, 2013. The *Columbia Gas Order* was preceded by a July 16 Staff Notice of Alleged Violations related to the same matters.

- **New England Pipeline Proceedings**

The following New England pipeline projects are pending before the FERC:

- **Algonquin Incremental Market Project (AIM Project) (CPI4-96)**

- ▶ Algonquin Gas Transmission filed for Section 7(b) and 7(c) certificate Feb. 28, 2014
- ▶ 342,000 dekatherms/day of firm capacity to NY, CT, RI and MA.
- ▶ 37.6 miles of take-up, loop and lateral pipeline facilities in NY, CT, and MA and system modifications in NY, CT and RI. The system upgrades would also require the removal of some facilities.
- ▶ 10 firm shippers: Yankee Gas, NSTAR, Connecticut Natural Gas, Southern Connecticut, Narragansett Electric, Colonial Gas, Boston Gas, Bay State, Norwich Public Utilities, and Middleborough Gas and Electric (eight LDCs and two municipal utilities).
- ▶ Final EIS issued on Jan. 23, 2015.
- ▶ Certificate of public convenience and necessity granted Mar. 3, 2015 (must be constructed and in service within two years).<sup>122</sup>
- ▶ Construction began in May 2015.
- ▶ In-service: Nov. 2016 (anticipated).

- **Connecticut Expansion Project (CPI4-529)**

- ▶ Tennessee Gas Pipeline filed for Section 7(c) certificate July 31, 2014.
- ▶ 72,100 dekatherms/day of firm capacity.

<sup>120</sup> See *BR Pipeline Co. et al.*, 149 FERC ¶ 61,031 (Oct. 16, 2014).

<sup>121</sup> *Columbia Gas Transmission, LLC*, 152 FERC ¶ 61,089 (July 30, 2015) ("*Columbia Gas Order*").

<sup>122</sup> Order Issuing Certificate and Approving Abandonment, *Algonquin Gas Transmission LLC*, 150 FERC ¶ 61,163 (Mar. 3, 2015), *reh'g requested*.

- ▶ 13.26 miles of three looping segments and facility upgrades/modifications in NY, MA and CT.
- ▶ Three firm shippers: Connecticut Natural Gas, Southern Connecticut Gas, and Yankee Gas.
- ▶ Authorization requested by July 31, 2015 (FERC EA still pending).
- ▶ Construction expected to begin Winter 2015/16.
- ▶ In-service: Nov 2016 (anticipated).
- ***Constitution Pipeline (CPI3-499) and Wright Interconnection Project (CPI3-502)***
  - ▶ Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
  - ▶ 650,000 dekatherms/day of firm capacity from Susquehanna County, PA through NY to Iroquois/Tennessee interconnection (Wright Interconnection).
  - ▶ New 122-mile interstate pipeline.
  - ▶ Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
  - ▶ Final EIS completed on Oct 24, 2014.
  - ▶ Certificates granted Dec 2, 2014 (must be constructed and in service within two years);
  - ▶ Construction expected to begin third quarter 2015 (after final Federal Authorizations).
- ***Salem Lateral Project (CPI4-522)***
  - ▶ Algonquin Gas Transmission filed application Jul 10, 2013.
  - ▶ 115,000 dekatherms/day of firm capacity.
  - ▶ 1.2 miles of pipeline to 630 MW Salem Harbor Station and other Salem, MA facilities.
  - ▶ Footprint Power sole firm customer.
  - ▶ FERC environmental assessment issued Dec 2, 2014.
  - ▶ Certificate granted May 14, 2015 (must be constructed and in service within two years).<sup>123</sup>
  - ▶ Construction began in May 2015.
  - ▶ In-Service: Nov 2015 (anticipated).

#### XIV. State Proceedings & Federal Legislative Proceedings

*No Activity to Report.*

#### XV. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit). An “\*\*” following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; [pmgerity@daypitney.com](mailto:pmgerity@daypitney.com)).

<sup>123</sup> Order Issuing Certificate, *Algonquin Gas Transmission LLC*, 151 FERC ¶ 61,118 (May 14, 2015).

- **Base ROE Complaints (2012 and 2014) (15-1212)**  
**Underlying FERC Proceedings: EL13-33; EL14-86<sup>124</sup>**  
**Appellants: New England Transmission Owners**

On July 13, 2015, the TOs filed a petition for review of the FERC's orders in the 2012 and 2014 ROE complaint proceedings. On July 16, the Court issued a scheduling order directing, among other things, a statement of issues and procedural motions to be filed by August 17 and dispositive motions to be filed by August 31; briefing is deferred until further order of the court.

- **Order 1000 Compliance Filings (15-1139, 15-1141\*\*) (consolidated)**  
**Underlying FERC Proceedings: ER13-193; ER13-196<sup>125</sup>**  
**Appellants: New England Transmission Owners (NETOs); NESCOE/CT DEEP/CT PURA, et al.**

On May 15, 2015, NETOs<sup>126</sup> and NESCOE, *et al.*, filed a petition for review of the FERC's orders in the *Order 1000* Compliance Filing proceeding. On June 15, the parties filed a joint statement of issues and unopposed motion regarding briefing format. On June 18, a Joint Statement of issues and docketing statement was filed. On July 2, the Court granted all motions to intervene. On July 16, the Court directed parties to submit proposed formats for the briefing of the cases within 30 days.

- **Base ROE Complaint (2011) (15-1118, 15-1119, 15-1121\*\*) (consolidated)**  
**Underlying FERC Proceedings: EL11-66<sup>127</sup>**  
**Appellants: NETOs**

On April 30, 2015, NETOs filed a petition for review of the FERC's orders in the 2011 Base ROE Complaint Proceeding. Motions for leave to intervene have been filed by NEPOOL, EMCOS,<sup>128</sup> NJ Division of Rate Counsel, NHEC, MMWEC, CT PURA, CT OCC, CT AG, NJ BPU, Delaware PSC, and Coalition of MISO Transmission Customers. The Court granted all motions to intervene on June 23. On July 9, the Court directed parties to file proposed briefing formats by August 8, 2015.

- **FCM Administrative Pricing Rules Complaint (15-1071\*\*) (consolidated)**  
**Underlying FERC Proceedings: EL14-7<sup>129</sup>**  
**Appellants: NEPGA**

On March 31, 2015, NEPGA filed a petition for review of the FERC's orders on NEPGA's FCM Administrative Pricing Rules Complaint. A Docketing Statement Form, Statement of Issues to be Raised, and Petitioners' Appearances were filed on April 23, 2015. Also on April 23, 2015, NEPGA requested that the case be held in abeyance pending the FERC's issuance of an order on rehearing of its initial order in *Exelon Corporation v. ISO New England Inc. (EL15-23)*. Motions for leave to intervene have been filed by NEPOOL, CT PURA, CT OCC, NESCOE, NECPUC, NHEC, and PSEG. On May 22, the Court granted all motions to intervene and NEPGA's motion to hold the case in abeyance pending a decision in EL15-23. Motions to govern future proceedings are due 30 days from the completion of the FERC proceedings in EL15-23. NEPGA was directed to file an abeyance status report on or before August 20, 2015.

<sup>124</sup> 147 FERC ¶ 61,235 (June 19, 2014); 149 FERC ¶ 61,156 (Nov. 24, 2014); 151 FERC ¶ 61,125 (May 14, 2015).

<sup>125</sup> 150 FERC ¶ 61,209 (Mar. 19, 2015); 143 FERC ¶ 61,150 (May 17, 2013).

<sup>126</sup> "NETOs" are Emera Maine; Central Maine Power Co., National Grid; New Hampshire Transmission ("NHT"), Eversource (on behalf of its electric utility company affiliates CL&P, WMECO, PSNH, and NSTAR), UI, and Vermont Transco.

<sup>127</sup> 150 FERC ¶ 61,165 (Mar. 3, 2015); 149 FERC ¶ 61,032 (Oct. 16, 2014); 147 FERC ¶ 61,234 (June 19, 2014).

<sup>128</sup> "EMCOS" are Taunton, Reading, Hingham, and Braintree.

<sup>129</sup> 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

- **Demand Curve Changes (15-1070\*\*)**  
**Underlying FERC Proceedings: ER14-1639**<sup>130</sup>  
**Appellants: NextEra, NRG and PSEG**

On March 30, 2015, NextEra, NRG and PSEG filed a petition for review of the FERC's orders in the Demand Curve Changes proceedings. Motions for leave to intervene have been filed by NEPOOL, the ISO, CT PURA, NHEC, CPV, Entergy, and NESCOE. A Docketing Statement Form, Statement of Issues to be Raised, and Appearances were filed by Petitioners on April 30, 2015. The Petitioners' Non-Binding Statement of Issues laid out various challenges to the renewables exemption that was approved as part of the FERC's Demand Curve Orders. On May 28, the Court granted all filed motions to intervene and ordered intervenors to show by June 29 cause why they should not be limited to one joint brief in support of the FERC. On June 26, CT PURA filed a statement requesting permission from the Court to file its own brief in support of the FERC. Also on June 26, NESCOE, CPV and NHEC filed a statement regarding briefing format.

- **FCA8 Results (14-1244, 14-1246 (consolidated))**  
**Underlying FERC Proceedings: ER14-1409**<sup>131</sup>  
**Appellants: Public Citizen and CT AG**

On November 14, 2014, Public Citizen and the CT AG filed petitions for review of the FERC's action on the FCA8 Results Filing, which became effective by operation of law on September 16, 2014. These proceedings have been consolidated. A Docketing Statement Form and Statement of Issues to be Raised were filed by Petitioners by December 22, 2014. On January 2, 2015, the FERC filed a motion to dismiss the petitions for lack of jurisdiction. The FERC argued that the Court lacks jurisdiction because Petitioners did not challenge a FERC "order" within the meaning of section 313 of the FPA, or "agency action" reviewable under the Administrative Procedures Act. On January 15, EPSA and NEPGA jointly filed a motion supporting the FERC's motion to dismiss. On January 26, Connecticut<sup>132</sup> and Public Citizen opposed the FERC's motion to dismiss. On February 5, the FERC replied to the Public Citizen and CT AG responses. On April 7, the Court ordered that the motion to dismiss be referred to the merits panel and parties were directed to address in their briefs the issues presented in the motion to dismiss rather than incorporate those arguments by reference. On April 9, the FERC filed an unopposed motion for a schedule setting a minimum 60-day briefing interval for the FERC. On April 10, the Court ordered that parties submit proposed formats for the briefing of the consolidated cases by May 11. The parties filed a joint proposed briefing schedule on May 11. On July 1, the Court issued a briefing schedule -- brief for State Petitioners due 9/4/2015; brief for Public Citizen due 9/4/2015; brief for Respondent due 11/3/2015; brief for FERC/Intervenors due 11/18/2015; reply briefs for Petitioners due 12/2/2015; final briefs due 12/23/2015.

- **2013/14 Winter Reliability Program (14-1104, 14-1105, 14-1103 (consolidated))**  
**Underlying FERC Proceedings: ER13-1851**<sup>133</sup> **and ER13-2266**<sup>134</sup>  
**Appellants: TransCanada and RESA**

On June 6, 2014, TransCanada and the Retail Energy Supply Association filed petitions for review of the FERC's orders on the 2013/14 Winter Reliability Program (14-1104 and 14-1105, respectively). Also on June 6, 2014, TransCanada filed a petition for review of FERC's orders on the 2013/14 Winter Reliability Program Bid Results Filings (ER14-1103). On July 3, 2014, these proceedings were consolidated. On July 7, 2014, the FERC requested a minimum of 60 days after Petitioners' opening briefs to file its brief. On July 23, leave to intervene was granted to ISO-NE, NEPGA, PSEG and Essential Power. On September 29, 2014, TransCanada, RESA, FERC, ISO-NE, Essential Power MA, PSEG and NEPGA filed a proposed joint, unopposed briefing format and schedule. A Joint Brief for Petitioners was filed on November 24 (as corrected on December 1). At the FERC's

<sup>130</sup> 150 FERC ¶ 61,065 (Jan. 30, 2015); delegated letter order (Nov. 13, 2014); 147 FERC ¶ 61,173 (May 30, 2014).

<sup>131</sup> Notice of Filing Taking Effect by Operation of Law, *ISO New England Inc.*, Docket No. ER14-1409 (Sep. 16, 2014); Notice of Dismissal of Pleadings, *ISO New England Inc.*, Docket No. ER14-1409 (Oct. 24, 2014).

<sup>132</sup> For purposes of this proceeding, "Connecticut" means the CT AG, CT PURA and CT OCC.

<sup>133</sup> 144 FERC ¶ 61,204 (Sep. 16, 2013); 147 FERC ¶ 61,026 (Apr. 8, 2014).

<sup>134</sup> 145 FERC ¶ 61,023 (Oct. 7, 2013); 147 FERC ¶ 61,027 (Apr. 8, 2014).

request, the Court ordered that a revised briefing schedule be applied in this case (effectively extending the overall briefing schedule by one month. Briefs for Respondent and Respondent-Intervenors were filed February 13 and March 2, respectively. Petitioners' Joint Reply Brief was filed on March 25; the Deferred Appendix, April 1, 2015. Final Briefs were filed on April 15, 2015. Since the last Report, oral argument before a merits panel to be named 30-days ahead of the oral argument, was scheduled for September 15, 2015.

- **New England's Order 745 Compliance Filing (12-1306)**  
**Underlying FERC Proceedings: ER11-4336<sup>135</sup>**  
**Appellants: EPSA and NEPGA**

On July 16, 2012, EPSA and NEPGA filed a petition for review of FERC's orders on New England's *Order 745* (Demand Response Compensation) filings. On August 16, 2012, EPSA and NEPGA filed a statement of issues as well as an unopposed motion to hold case in abeyance pending the final resolution of Case Nos. 11-1486, et al. (*EPSA et al. v. FERC*) (see *Orders 745* and *745-A* below). On August 23, 2012, the Court granted the motion to hold the case in abeyance. Motions to govern future proceedings will be due 30 days following the issuance of the mandate in the *Order 745* appeal.

- **Orders 745 and 745-A (FERC v. EPSA, Supreme Court, 14-840 and 14-841)**  
**Underlying FERC Proceedings: RM10-17-000<sup>136</sup>**  
**Appellants: FERC and EnerNOC**

On January 15, the Solicitor General of the United States, on behalf of the FERC, filed with the Supreme Court a petition for a writ of certiorari seeking review of the District Court's May 23 Decision.<sup>137</sup> Respondents brief in opposition to that writ, pursuant to an order of the Court extending the time for responses, was filed on March 19. Petitioner's reply was filed on April 7. The Supreme Court granted certiorari on May 4, 2015. On May 27, the Supreme Court granted extensions to file petitioners' briefs to July 9, 2015 and respondents' brief to August 31, 2015. On July 9, briefs were submitted by EnerNOC, FERC, CA PUC, Joint States, and PJM. Amicus curiae briefs were submitted on July 16. Oral argument is now scheduled for October 14, 2015.

As previously reported, the DC Circuit vacated *Order 745*<sup>138</sup> in its entirety as impermissibly encroaching on "states' exclusive jurisdiction to regulate the retail market" in a 2-1 decision ("Decision") issued on May 23, 2014. The DC Circuit vacated *Order 745* on two separate and independent grounds. First, it held that the FERC does not have jurisdiction to regulate demand response. The Court reasoned that: (i) the states retain exclusive authority to regulate the retail market; (ii) absent an express statutory grant of authority, the FERC cannot regulate areas left to the states; (iii) the FPA provides the FERC with authority over wholesale sales of electricity, but demand response is not such a sale; (iv) the authority of the FERC to regulate wholesale power rates under the FPA cannot be read so broadly as to allow direct regulation of demand response; and (v) demand response, while not necessarily a retail sale, is part of the retail market, involving retail customers, their decision whether to purchase at retail, and the levels of retail electricity consumption. Therefore, the Court concluded, the FERC has no authority to directly regulate demand response. "FERC's authority over demand response resources is limited: its role is to assist and advise state and regional programs."

As an alternative and secondary basis for its decision against *Order 745*, the Court concluded that the FERC order was "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." The Court found that the FERC failed to reasonably consider and address arguments that *Order 745* will result in over-compensation of demand response resources, resulting in unjust and discriminatory rates. The Court

<sup>135</sup> 138 FERC ¶ 61,042 (Jan. 19, 2012); 139 FERC ¶ 61,116 (May 17, 2012).

<sup>136</sup> 134 FERC ¶ 61,187 (Mar. 15, 2011); 137 FERC ¶ 61,215 (Dec. 15, 2011).

<sup>137</sup> *EPSA v. FERC*, 753 F.3d 216 (May 23, 2014).

<sup>138</sup> *Order 745* required RTOs and ISOs to include provisions in their tariffs that assured demand response would be paid at LMP for interrupting their loads when such interruption was cost effective.

further found that the FERC failed to demonstrate how its proposed pricing construct would result in just compensation. The Decision and preliminary implications of the Decision were summarized in more detail in the memo included with the supplemental materials circulated and posted for the June 6 meeting.

On July 7, the FERC petitioned the Court for rehearing *en banc* of the May 23 Decision. On July 18, the Court, on its own motion, directed EPSA, APPA, NRECA, Old Dominion and EEI (“Petitioners”) to file a joint response to the FERC petition for rehearing. That response was filed on August 4, 2014. The petition for rehearing *en banc* was denied on September 17, 2014. As previously reported, the DC Circuit directed its clerk to withhold the Court’s mandate pending the Supreme Court’s final disposition.

- **CPV Maryland, LLC v. PPL EnergyPlus et al. (Supreme Court, 14-623)**

A petition for a writ of certiorari in this case was filed on November 26, 2014 and placed on the Supreme Court’s docket on November 28, 2014 as No. 14-623. The parties consented to the filing of amicus curiae briefs, and such briefs were filed by NARUC, the State of Connecticut, and APPA. Respondents (PPL EnergyPlus, LLC, et al.) filed a response on February 11. Petitioner CPV Maryland, LLC replied on February 24. On March 23, the Court invited the Solicitor General to file a brief in the case expressing the views of the United States. This matter is now before the Court.

As previously reported, on June 2, 2014, the 4th Circuit Court of Appeals affirmed the September 30, 2013 decision of the United States District Court for the District of Maryland<sup>139</sup> which found that a Maryland Public Service Commission (“MD PSC”) order directing three Maryland distribution utilities to enter into a ‘contract for differences’ for capacity and energy in the PJM control area (the “CfD”) with a gas-fired merchant generator selected by the MD PSC (the “MD PSC Order”) violated the Supremacy Clause of the United States Constitution and cannot be enforced.<sup>140</sup> In affirming the District Court decision, the 4th Circuit found the MD PSC Order both field<sup>141</sup> and conflict pre-empted.<sup>142</sup>

With respect to field pre-emption, the 4th Circuit stated that a “wealth of case law confirms FERC’s exclusive power to regulate wholesale sales of energy in interstate commerce, including the justness and reasonableness of the rates charged.”<sup>143</sup> It found the federal scheme (i.e. the PJM Market) “carefully calibrated to protect a host of competing interests” (representing “a comprehensive program of regulation that is quite sensitive to external tampering”),<sup>144</sup> and leaving “no room either for direct state regulation of the prices of interstate wholesales of [energy], or for state regulations which would indirectly achieve the same result.” Accordingly, the 4th Circuit concluded that the MD PSC Order “field preempted because it functionally sets the rate that CPV

<sup>139</sup> *PPL EnergyPlus, LLC v. Nazarian*, 974 F.Supp. 2d 790 (D. Md. Sep. 30, 2013); 2013 U.S. Dist. LEXIS 140210, 2013 WL 5432346 (“*District Court Decision*”). The *District Court Decision* was summarized in past Litigation Reports.

<sup>140</sup> *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467; 2014 U.S. App. LEXIS 10155.

<sup>141</sup> “Field preemption” is a doctrine based on the Supremacy Clause of the U.S. Constitution that holds that any federal law, including regulations of a federal agency, takes precedence over any conflicting state law. Preemption can be implied when federal law/regulation “occupies the field” in which the state is attempting to act/regulate. Field preemption occurs when there is “no room” left for state regulation. Accordingly, a state may not pass a law or take any action in a field, like the regulation of wholesale power sales, pervasively regulated by federal law/regulation.

<sup>142</sup> “Conflict preemption” occurs where there is a conflict between a state law and a federal law. (“[E]ven if Congress has not occupied the field, state law is naturally preempted to the extent of any conflict with a federal statute.”). Such a conflict occurs when “the challenged state law stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress. The court must look to ‘the entire scheme of the statute’ and determine ‘[i]f the purpose of the [federal] act cannot otherwise be accomplished—if its operation with its chosen field [would] be frustrated and its provisions be refused their natural effect. Where a state law conflicts with a federal law, the Court does not balance the competing federal and state interests. Any state law, however clearly within a State’s acknowledged power, which interferes with or is contrary to federal law, must yield.”

<sup>143</sup> Slip op. at p. 14.

<sup>144</sup> *Id.* at p. 10.

receives for its sales in the PJM auction.”<sup>145</sup> The MD PSC Order “compromises the integrity of the federal scheme and intrudes on FERC’s jurisdiction” because the MD PSC Order “effectively supplants the rate generated by the auction with an alternative rate preferred by the state.” The 4th Circuit rejected arguments that the CfD payments “represented a separate supply-side subsidy implemented entirely outside the federal market.”<sup>146</sup> And, even if the presumption against preemption were to apply, the Court found that that it was “overcome by the text and structure of the FPA, which unambiguously apportions control over wholesale rates to FERC.”<sup>147</sup>

With respect to conflict pre-emption, the 4th Circuit found that the MD PSC Order “presents a direct and transparent impediment to the functioning of the PJM markets, and is therefore preempted”.<sup>148</sup> Preemption was appropriate because of the “extensive and disruptive” impact of the MD PSC Order on matters within federal control (the PJM markets). It found that the MD PSC Order had “the potential to seriously distort the PJM’s auction’s price signals, thus ‘interfer[ing] with the method by which the federal statute (i.e. the PJM Markets) was designed to reach its goals.’”<sup>149</sup> “Maryland’s initiative disrupts [the PJM scheme] by substituting the state’s preferred incentive structure for that approved by FERC.”<sup>150</sup> “Maryland has sought to achieve through the backdoor of its own regulatory process what it could not achieve through the front door of FERC proceedings. Circumventing and displacing federal rules in this fashion is not permissible.”<sup>151</sup>

Petitions for rehearing *en banc* were filed by MD PSC and CPV Maryland on June 16, 2014. On June 17, 2014, the 4<sup>th</sup> Circuit stayed the mandate pending the *en banc* ruling on the Petitions. On June 30, 2014, the 4<sup>th</sup> Circuit denied the petitions for rehearing *en banc*.

- **CPV Power Development, Inc., et al. v. PPL EnergyPlus, LLC, et al. (Supreme Court, 14-634, 14-694)**

Petitions for a writ of certiorari in this case were filed on November 26, 2014 and December 10, 2014 and placed on the Supreme Court’s docket as Case Nos. 14-634 and 14-694, respectively. The parties consented to the filing of amicus curiae briefs, and such briefs were filed by NARUC, the State of Connecticut, APPA, AWEA, and the NY PSC. Since the last Report, Respondents (PPL EnergyPlus, LLC, et al.) filed a brief opposing the writ of certiorari on February 11. Petitioners (CPV Power Development, Inc., et al.) replied to that brief on February 20. On March 23, the Court invited the Solicitor General to file a brief in the case expressing the views of the United States.

As previously reported, on September 11, 2014, the 3rd Circuit Court of Appeals affirmed<sup>152</sup> the analogous October 11, 2013 decision of the United States District Court for the District of New Jersey declaring unconstitutional (and therefore null and void) New Jersey’s Long Term Capacity Agreement Pilot Program Act (“LCAPP”).<sup>153</sup> In affirming the New Jersey District Court’s decision, the 3rd Circuit concluded:

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<sup>145</sup> *Id.* at p. 16.

<sup>146</sup> *Id.* at pp. 18-19.

<sup>147</sup> *Id.* at p. 20. The Court noted the limited scope of its holding, which “is addressed to the specific program at issue” and did not “express an opinion on other state efforts to encourage new generation.” *Id.* at p. 21.

<sup>148</sup> *Id.* at p. 27.

<sup>149</sup> *Id.* at p. 23.

<sup>150</sup> *Id.* at p. 24. (“Two features of the Order render its likely effect on federal markets particularly problematic. First, as noted, the CfDs are structured to actually set the price received at wholesale. They therefore directly conflict with the auction rates approved by FERC. Second, the duration of the subsidy -- twenty years -- is substantial.”)

<sup>151</sup> *Id.* at p. 25.

<sup>152</sup> *PPL EnergyPlus, LLC v. Hanna*, 977 F.Supp.2d 372 (D. NJ. Oct. 11, 2013); 2013 U.S. Dist. LEXIS 147273, (“*NJ Order*”).

<sup>153</sup> *PPL EnergyPlus, LLC v. Hanna*, 766 F.3d 241; 2014 U.S. App. LEXIS 17557 (Sep. 11, 2014).

LCAPP compels participants in a federally-regulated marketplace to transact capacity at prices other than the price fixed by the marketplace. By legislating capacity prices, New Jersey has intruded into an area reserved exclusively for the federal government. Accordingly, federal statutory and regulatory law preempts and, thereby, invalidates LCAPP and the Standard Offer Capacity Agreements.<sup>154</sup>

No petition for rehearing or rehearing *en banc* was filed on or before September 25, 2014. Accordingly, the mandate was issued on October 3, 2014. As noted above, petitions for *certiorari* to the U.S. Supreme Court were filed and are pending before the Supreme Court.

- **Entergy Nuclear Fitzpatrick, LLC et al v. Zibelman et al (NY PSC Commissioners) (N.D.N.Y. 5:15-cv-00230-DNH-TWD)**

Entergy<sup>155</sup> filed, on February 27, in the United States District Court for the Northern District of New York, a Complaint that seeks a declaratory judgment that the NYPSC Commissioners' order ("Order") approving an agreement to keep NRG's 435 MW Dunkirk facility in the NYISO market, "repowered" as a natural gas-fired (rather than coal-fired) plant (the "Term Sheet")<sup>156</sup> is preempted by the FPA and invalid under the dormant Commerce Clause of the U.S. Constitution. Entergy also seeks a permanent injunction requiring the NYPSC Commissioners to withdraw its Order and/or preventing the NYPSC Commissioners from continuing to treat the Order as valid and binding. This case is noteworthy given the relationship of the issues raised to the Maryland and New Jersey CfD cases summarized above.

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<sup>154</sup> *Id.* slip op. at 31.

<sup>155</sup> Plaintiffs are Entergy Nuclear FitzPatrick, LLC ("FitzPatrick"); Entergy Nuclear Power Marketing, LLC ("ENPM"); and Entergy Nuclear Operations, Inc. ("ENOI").

<sup>156</sup> The Term Sheet provides that, in exchange for Dunkirk's commitment to participate in the NYISO energy and capacity markets through 2025, Dunkirk will receive out-of-market payments of \$20.4 million per year from National Grid and a \$15 million one-time subsidy from a New York State agency. Entergy asserts that the contract structure will lead Dunkirk to bid below its actual costs in the capacity auction, causing the auction market to "clear" at a lower price than otherwise would have resulted, and resulting in all generators receiving lower capacity revenues than they otherwise would have received.

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