David T. Doot
Secretary

January 29, 2016

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of February 5, 2016 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that a meeting of the Participants Committee will be held **on Friday, February 5, 2016, at 10:00 a.m.** at The Seaport Boston Hotel, 1 Seaport Lane, Boston, MA. The Participants Committee meeting will be held in Seaport Ballroom (in the Seaport Hotel) for the purposes set forth on the attached agenda and posted with the meeting materials at http://nepool.com/NPC_2016.php. For your information, this meeting is recorded, as are all the NEPOOL Participants Committee meetings.

Directions to the Seaport Hotel are included with this notice. As previously noted, the room block at the Seaport for the February 5 meeting closed on January 22. Should you still need a room, please contact the hotel directly (1-877-732-7678) and reference the "NEPOOL Participants Committee" block of rooms to see if any rooms are still available or you can be placed on a wait list.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the Participants Committee meeting held on January 8, 2016. Preliminary minutes for the January 8 meeting, marked to show changes from the draft circulated with the initial notice, are included with this notice and posted at http://nepool.com/NPC_2016.php.

2. To adopt and approve all actions recommended by the Technical Committees set forth on the Consent Agenda included with this supplemental notice.

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

4A. To receive an ISO Internal Market Monitor summary of its 2015 Q3 (Jul-Sep) and Fall (Sep-Nov) Quarterly Markets Reports. The IMM's summary presentation will be circulated and posted with the additional materials. Copies of the full Reports, filed with the FERC on December 22, 2015 and January 29, 2016, respectively, are posted with the composite meeting materials.

5. To consider and take action, as appropriate, on revisions to Section II of the ISO New England Transmission, Markets and Services Tariff to reflect generator interconnection rule changes. Background materials and a draft resolution are included with this supplemental notice.

6. To consider and take action, as appropriate, on NEPOOL comments on the FERC's Reactive Power Proposal in FERC Docket No. RM16-1-000. Background materials and a draft resolution are included with this supplemental notice.

7. To consider a NEPOOL scenario analysis proposal to study the implications of public policy on market design, reliability, resource metrics, total cost, emissions, system operability and the ability to support new generation. Background materials may be circulated in advance of the meeting.

8. 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 and posted in advance of the meeting.

9. To receive reports from committees and subcommittees.

10. To transact such other business as may properly come before the meeting.

PRELIMINARY

A meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Friday, January 8, 2016. 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 who participated in the teleconference meeting.

Mr. Joel Gordon, Chairman, presided and Mr. David Doot, Secretary, recorded. Mr. Gordon welcomed those on the teleconference, including members, alternates and guests.

APPROVAL OF MINUTES OF DECEMBER 4, 2015 MEETING

Mr. Gordon referred the Committee to the preliminary minutes of the December 4, 2015 meeting as circulated in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the December 4 meeting were unanimously approved without change from the version circulated.

CONSENT AGENDA

Mr. Gordon referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved without discussion or comment.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO) referred the Committee to the summaries of the ISO Board and Board Committee meetings since the December 4 meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), reviewed highlights from the January COO report addressing operations through December 29 (December 28 for Daily Net Commitment Period Compensation (NCPC)), which had been circulated and posted in advance of the meeting. He began by noting that December 2015 was the warmest December since the implementation of Standard Market Design (SMD), with an average daily peak temperature of 52°F. The resulting average load for the month was approximately 13,500 MW. Focusing on report highlights: (i) Energy Market value was $222 million, down $69 million from November 2015 and $276 million from December 2014; (ii) natural gas prices were 37% lower than November 2015 average prices; (iii) Real-Time Hub locational marginal prices (LMPs) on average were 24% lower than November 2015 LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percentage of forecasted load, was 100% in December 2015, up from 98% in November 2015; and (v) NCPC for December 2015 (through December 28) totaled $4.88 million, which was 2.2% of the total energy Market value and was down $7.1 million from November 2015 and down $8.8 million from December 2014. Of those NCPC payments, first contingency payments, totaling $4.34 million, were $1.8 million lower than November's, there were no second contingency payments, compared to $4.5 million of such payments last month, and voltage support payments totaled $540,000, down $848,000 from November.

Dr. Chadalavada reported that the Interstate Reliability Project (IRP) was placed in-service in mid-December, increasing east-west transfer capability. He noted that the IRP should provide reliability benefits during peak summer months by allowing more power to flow from west to east and during off-peak months by reducing the need for supplemental commitments in

eastern New England during transmission and generation outages. Dr. Chadalavada committed in response to a question to have the ISO report to the Planning Advisory Committee on the impact, if any, of the IRP on the stability analysis underway for the greater Boston transmission upgrades.

Providing an update on the 2015/16 Winter Reliability Program, Dr. Chadalavada reported that no Program liquefied natural gas (LNG) and very little Program oil was used, and no winter Demand Response (DR) calls were made during the month of December given December's record warm temperatures. He stated that an updated slide reflecting the latest inventory levels for oil, LNG and DR participation would be circulated to the Committee early the following week.

In response to a member's question, Dr. Chadalavada observed that, since implementation of Coordinated Transaction Scheduling (CTS) on December 15, usage of the New England/New York interface had improved, there appeared to be closer correlation between forecast and Real-Time prices, and flows were predominantly trending in the direction or in quantities consistent with expectations given prevailing prices and economic conditions. He added that the ISO was planning to provide an update on the first 30-45 days' experience with CTS at the February Participants Committee meeting, and a more in-depth analysis on CTS following two full seasons' experience.

In response to a request, Dr. Chadalavada provided additional information on a Peak Energy Rent/Capacity deficiency event that had occurred on January 5. He reported that the ISO issued an Abnormal Conditions Alert (Master/Local Control Center Procedure No. 2 (M/LCC2)) on that day when there was a forced outage of one generator during the morning ramp and there were start-up and equipment issues with other resources that were not fuel supply issues. In

order to mitigate the Operating Reserve impact of the event, import transactions into New England were reduced by approximately 400 MW. He added that, while operating exposure was ultimately limited to the morning ramp, and Operating Procedure No. 4 (Action During a Capacity Deficiency) (OP-4) was not implemented, the system during that time was likely just a small event away from OP-4 implementation.

LITIGATION REPORT

Mr. Gordon referred the Committee to the January 6 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted the recent FERC order (EL16-15) initiating a Section 206 proceeding and directing that zonal sloped demand curves be implemented in time for FCA11, with a compliance filing to effect that implementation due on March 31. Dr. Chadalavada explained that the process and schedule for consideration of that compliance filing would be discussed with Participants at the January 12 Markets Committee meeting, with tentative plans to seek a short extension to the filing deadline so a vote on the filing could be conducted at the Participants Committee April 8 meeting. Before finalizing plans for the compliance filing process and schedule, Dr. Chadalavada indicated that the ISO wanted input from Participants and the States.

Mr. Patrick Gerity, NEPOOL Counsel, then highlighted the other Section 206 proceedings initiated the prior month, the January 11 comment date for responses to the ISO's proposed FCM Resource Retirement Reforms, and a December 22 remand by the DC Circuit Court of Appeals to the FERC of a portion of the FERC's orders on the 2013/14 Winter Reliability Program successfully challenged by TransCanada. Members were encouraged to contact NEPOOL Counsel with comments or questions on any of the reported matters.

COMMITTEE & OTHER REPORTS

Officers from each of the Technical Committees reported on the schedule for committee meetings in January. Mr. Robert Stein reported that the Reliability Committee was meeting January 20 to discuss the reliability impacts of proposed curves for FCA11. Mr. Fowler reported that the Markets Committee was meeting January 12-13, with the agenda including discussion of local demand curves and the schedule for responding to the FERC's directive on that issue, and discussion of changes to the Information Policy and Market Rule refinements. Mr. Jose Rotger reported that the Transmission Committee would meet on January 26 to vote on the ISO's proposed interconnection queue reform package, to discuss changes to the reactive capability audit provisions, and to address NEPOOL's responses, if any, to the FERC-initiated Section 206 proceeding addressing Regional Network Service and Local Network Service rates and rate protocols, and the Notice of Proposed Rulemaking that would eliminate the exemptions for wind generators from the requirement to provide reactive power. Mr. Ken Dell Orto reported that the next Budget & Finance Subcommittee meeting was scheduled for January 29 and would include a review of any received Generation Information System exemption requests. Mr. Gordon reported that a Scenario Analysis Working Group meeting was tentatively scheduled for January 22 at Day Pitney's offices in Boston. A revised draft proposal would be circulated in advance of the Working Group meeting.

Ms. Heather Hunt reported on two background whitepapers issued by NESCOE during December, one providing a history of electric restructuring in New England and a second identifying and discussing various mechanisms available to states to further their public policy initiatives. She stated both papers were posted and available in the resource center of the NESCOE website.

OTHER BUSINESS

Mr. Gerity reported that the next Participants Committee meeting was scheduled for February 5, 2016 at the Seaport Hotel in Boston, MA.

There being no further business, the meeting adjourned at 10:36 a.m.

Respectfully submitted,

_____
David T. Doot, Secretary

ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN
JANUARY 8, 2016 PARTICIPANTS COMMITTEE TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ashburnham Municipal Light Plant	Publicly Owned	Michal Lynch		
Belmont Municipal Light Department	Publicly Owned		Phil Smith	
Boylston Municipal Light Department	Publicly Owned	Michael Lynch		
BP Energy Company	Supplier			Nancy Chafetz
Brookfield Energy Marketing	Supplier	Aleksandar Mitreski		
Calpine Energy Services, LP	Supplier		Brett Kruse	
Central Maine Power (CMP)/ United Illuminating (UI)	Transmission	Eric Stinneford		
Chester Municipal Light Department	Publicly Owned	Phil Smith		
Chicopee Municipal Lighting Plant	Publicly Owned	Michael Lynch		
CLEAResult Consulting, Inc.	AR	Doug Hurley		
Concord Municipal Light Plant	Publicly Owned		Phil Smith	
Conn. Municipal Electric Energy Cooperative	Publicly Owned	Brian Forshaw		
Connecticut, State of, Office of Consumer Counsel	End User			Dave Thompson
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
Danvers Electric Division	Publicly Owned		Phil Smith	
Dominion Energy Marketing, Inc.	Generation	James Davis		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade	Supplier			William Fowler
Emera Maine/Emera Energy Services Subsidiaries	Transmission		Jose Rotger	Jeff Jones Stacy Dimou
Energy America, LLC	Supplier			Nancy Chafetz
Entergy Nuclear Power Marketing LLC	Generation		Ken Dell Orto	
Essential Power, LLC	Generation	M.Q. Riding	William Fowler	
Eversource Energy	Transmission	James Daly	Joe Staszowski	
Exelon Generation Company	Supplier		William Fowler	
Galt Power, Inc.	Supplier	Nancy Chafetz		
GDF SUEZ Energy Marketing NA, Inc.	Generation	Thomas Kaslow		
Generation Group Member	Generation		Abby Krich	Bob Stein
Georgetown Municipal Light Department	Publicly Owned		Phil Smith	
Granite Ridge Energy, LLC	Supplier		William Fowler	
Groton Electric Light Department	Publicly Owned	Michael Lynch		
Groveland Electric Light Department	Publicly Owned		Phil Smith	
H.Q. Energy Services (U.S.) Inc.	Supplier		Bob Stein	Abby Krich
Harvard Dedicated Energy Ltd	End User			Paul Peterson Doug Hurley
High Liner Foods (USA)	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Phil Smith	
Holden Municipal Light Department	Publicly Owned	Michael Lynch		
Holyoke Gas & Electric Department	Publicly Owned	Michael Lynch		
Hull Municipal Lighting Plant	Publicly Owned	Michael Lynch		
Industrial Energy Consumer Group	End User	Donald Sipe		
Ipswich Municipal Light Department	Publicly Owned	Michael Lynch		
Littleton (MA) Electric Light and Water Department	Publicly Owned		Phil Smith	
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		
Maine Skiing, Inc.	End User	Donald Sipe		
Mansfield Municipal Electric Department	Publicly Owned	Michael Lynch		
Marblehead Municipal Light Department	Publicly Owned	Michael Lynch		
Marble River, LLC	Supplier		John Brodbeck	
Massachusetts Attorney General's Office	End User	Fred Plett		

ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN
JANUARY 8, 2016 PARTICIPANTS COMMITTEE TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Massachusetts Development Finance Agency	Publicly Owned		Phil Smith	
Mass. Municipal Wholesale Electric Company	Publicly Owned	Michael Lynch		
Merrimac Municipal Light Department	Publicly Owned		Phil Smith	
Middleborough Gas and Electric Department	Publicly Owned	Michael Lynch		
Middleton Municipal Electric Department	Publicly Owned		Phil Smith	
National Grid	Transmission	Tim Brennan	Tim Martin	
New Hampshire Electric Cooperative, Inc.	Publicly Owned	Steve Kaminski		Brian Forshaw Michael Lynch David Mullett
New Hampshire Office of Consumer Advocate	End User	Paul Peterson		
NRG Power Marketing, Inc.	Generation	Dave Cavanaugh		
Pascoag Utility District	Publicly Owned		Phil Smith	
Paxton Municipal Light Department	Publicly Owned	Michael Lynch		
Peabody Municipal Light Plant	Publicly Owned	Michael Lynch		
PowerOptions, Inc.	End User		Meg Lusardi	
Princeton Municipal Light Department	Publicly Owned	Michael Lynch		
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Repsol Energy North America	Supplier		Nancy Chafetz	
Rowley Municipal Lighting Plant	Publicly Owned		Phil Smith	
Russell Municipal Light Dept	Publicly Owned	Michael Lynch		
Shrewsbury Electric & Cable Operations	Publicly Owned	Michael Lynch		
Small LR Group Member	AR	Doug Hurley	Brad Swalwell	
Small RG Group Member	AR	Erik Abend		
South Hadley Electric Light Department	Publicly Owned	Michael Lynch		
Sterling Municipal Electric Light Department	Publicly Owned	Michael Lynch		
Stowe Electric Department	Publicly Owned		Phil Smith	
SunEdison (First Wind Energy Marketing)	AR	John Keene		
Taunton Municipal Lighting Plant	Publicly Owned		Phil Smith	
Templeton Municipal Lighting Plant	Publicly Owned	Michael Lynch		
The Energy Consortium	End User			Paul Peterson Doug Hurley
Union of Concerned Scientists	End User		Francis Pullaro	
Utility Services Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		
Vermont Electric Power Company, Inc.	Transmission	Francis Ettori		
Vermont Energy Investment Corporation	AR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned	David Mullett		
Vitol Inc.	Supplier	Joseph Wadsworth		
Wakefield Municipal Gas and Light Department	Publicly Owned	Michael Lynch		
Wallingford DPU Electric Division	Publicly Owned	Phil Smith		
Wellesley Municipal Light Plant	Publicly Owned		Phil Smith	
West Boylston Municipal Lighting Plant	Publicly Owned	Michael Lynch		
Westfield Gas & Electric Department	Publicly Owned		Phil Smith	
Wheelabrator North Andover Inc.	AR	William Fowler		

CONSENT AGENDA

From the notice of actions of the January 12-13, 2016 *Markets Committee*[1] meeting, dated January 14, 2016, which has been previously circulated:

1. **Information Policy Revisions (Market Participant Default Notification Changes)**

   Support revisions to Section 2.3 of the Information Policy to update the Information Policy and to support disclosure, through a revised Information Notification form, of information regarding Market Participant defaults under the Financial Assurance and Billing Policies, as recommended by the Markets Committee at its January 12-13, 2016 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.

[1] Markets Committee Notices of Actions are posted on the ISO website at: http://www.iso-ne.com/committees/markets/markets-committee.

Summary of ISO New England Board and Committee Meetings

February 5, 2016 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee met by teleconference on January 12. On January 21, the Compensation and Human Resources Committee, the System Planning and Reliability Committee, the Markets Committee, and the Board of Directors each met in Holyoke.

At its January 12 Meeting, the Compensation and Human Resources Committee was provided with an overview regarding upcoming negotiations with the union representing system operators. Next, the Committee confirmed the budgets for merit and promotional increases using updated compensation survey information. The Committee then met in executive session to review corporate goals for 2016.

At its January 21 Meeting, the Compensation and Human Resources Committee considered a variety of compensation-related matters. During executive session, the Committee reviewed the goal achievement process and the various metrics for measuring achievement. Finally, the Committee held an initial discussion regarding corporate performance for 2015 and officer compensation for 2016.

The System Planning and Reliability Committee received an update on compliance matters, and noted there were no recommended improvements resulting from the Northeast Power Coordinating Council audit. Next, the Committee discussed the audit being performed by the Federal Energy Regulatory Commission. The Committee discussed ongoing compliance activities related to Order 1000. The Committee also received an overview of preparations for the 10th Forward Capacity Auction. Finally, the Committee held an executive session to assess achievement of 2015 corporate goals.

The Markets Committee reviewed reports from the internal and external market monitors. There was a general discussion concerning the impact of low fuel prices and overall economic conditions on the wholesale electricity market. The Committee

discussed factors affecting the number of mitigation events, and how market concentration in the energy market is tracked by the Internal Market Monitor. Next, the Committee discussed the performance of the new Coordinated Transaction Scheduling mechanism and how the mechanism appears to be working well. The Committee received an update on the effort to develop zonal demand curves for the capacity market, and discussed the options for revising the existing system demand curve to be consistent with the new zonal demand curve design. The Committee discussed stakeholder reaction to the demand curve proposal. During executive session, the Committee assessed achievement of 2015 corporate goals.

The Board of Directors met and received an update from the Chief Executive Officer, in which he discussed the demand curve issues, and reports from the standing committees. The Board also approved minor changes to the Audit and Finance Committee charter, and discussed the policy on reimbursement for director education. During executive session, the Board approved the corporate goals for 2016.

FEBRUARY 5, 2016 | BOSTON, MA

NEPOOL Participants Committee Report

February 2016

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

- Highlights Page 3
- System Operations Page 15
- Market Operations Page 26
- Back-Up Detail Page 43
  - Load Response Page 44
  - New Generation Page 46
  - Forward Capacity Market Page 53
  - Reliability Costs - Net Commitment Period Compensation (NCPC) Operating Costs Page 59
  - Regional System Plan (RSP) Page 90
  - Operable Capacity Analysis – Winter 2016 Page 119
  - Operable Capacity Analysis – Spring 2016 Page 126
  - Operable Capacity Analysis – Appendix Page 133

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Energy Market Value was $408M over the period, up $159M from December 2015 and down $463M from January 2015
  - January natural gas prices over the period were 114% higher than December 2015 average values
  - Average RT Hub Locational Marginal Prices ($35.73/MWh) over the period were 67% higher than December 2015 averages
  - Average January 2016 natural gas prices and RT Hub LMPs over the period were down 48% and 46%, respectively, from January 2015 averages
- Average DA cleared physical energy in the peak hours as percent of forecasted load was 100.1% during January, up from 99.9% during December

All data through January 27 (RT NCPC through January 25) except where otherwise noted.

Underlying natural gas data furnished by:

ice Global markets in clear view

***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)
  - January NCPC payments totaled $5.7M, up $9K from December and down $3.1M from January 2015
    - January NCPC payments attributable to the RT evaluation of non fast-start units that cleared DA totaled $3.0M
  - First Contingency payments totaled $5.4M, up $254K from December
    - $5.1M paid to internal resources, up $345K from December
      - $707K charged to DALO, $4.2M to RT Deviations
    - $246K paid to resources at external locations, down $91K from December
      - $23K charged to DALO at external locations, $223K to RT Deviations
  - Second Contingency payments totaled $0 (second consecutive month)
  - Voltage payments were $290K, down $250K from December
  - NCPC payments over the period as percent of Energy Market value were 1.4%

Highlights, cont.

- New economic study requests are due to the ISO by April 1
  - 2015 economic planning studies are underway
  - All three study requests focus on the impacts of wind integration
  - ISO is working with NEPOOL on the NEPOOL 2016 economic study request
- FCA #10 is scheduled to begin on Monday, February 8
  - Results filing to be made with the FERC by the end of February

Forward Capacity Market (FCM) Highlights

- CCP #4 (2013-2014)
  - Less than 4 MW of resources are non-commercial at this time
- CCP #5 (2014-2015)
  - Less than 17 MW of resources are non-commercial at this time
- CCP #6 (2015-2016)
  - Less than 123 MW of resources are non-commercial at this time
- CCP #7 (2016-2017)
  - Updated Installed Capacity Requirement values were filed with FERC on December 1, 2015 and an order was received accepting the values on January 29
  - Third bilateral transaction window closed on December 8, 2015 and results were posted on January 8
  - Third reconfiguration auction will be March 1-3
    - Based on results of the second reconfiguration auction, entering the CCP, the Transmission Security Analysis margin for NEMA/Boston will be about 356 MW short. ISO Operations is working with the Local Control Centers to address this deficiency.

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP #8 (2017-2018)
  - Second bilateral transaction window will be May 2-6
  - Second reconfiguration auction will be August 1-3
- CCP #9 (2018-2019)
  - First bilateral transaction window will be April 1-7
  - First reconfiguration auction will be June 1-3
- CCP #10 (2019-2020)
  - Forward Capacity Auction to commence on February 8
- CCP #11 (2020-2021)
  - Show of interest window will NOT open on February 16, 2016 (current rules) pending a FERC ruling on the retirement reforms proposal. If FERC approves the proposal as filed, the window is expected to open on April 22, 2016.

Highlights, cont.

- The lowest 50/50 and 90/10 Winter Operable Capacity Margin is projected for week beginning February 6, 2016.
- The lowest 50/50 and 90/10 Spring Operable Capacity Margin is projected for week beginning May 7, 2016.

2015/16 Winter Reliability Program

- **Oil Program**
  - 77 units in the program for a total of 4.489 million barrels of oil
  - 2.954 million barrels of the total inventory are eligible for compensation per the winter program rules
  - Maximum oil program cost exposure is expected to be $38.11M (@$12.90/barrel)
- **LNG Program**
  - 8 units in the program representing 1.278 million MMBTU
  - Maximum LNG program cost exposure is expected to be $2.75M (@$2.15/MMBTU)
- **DR Program**
  - 6 assets in the program providing 26.5 MW of interruption capability
  - Maximum DR program cost exposure is anticipated to be $132K

2015/16 Winter Program Usage

- Winter Program Oil usage:
  - Dec 2015: 21,251 BBLs
  - Jan 2016: 75,277 BBLs (preliminary and subject to confirmation)

- Winter Program LNG usage:
  - Dec 2015: No Program LNG used
  - Jan 2016: No Program LNG used

- Winter Program DR usage:
  - Dec 2015: None
  - Jan 2016: 1 event – January 5th 7:03 am – 10:10am, all winter program DR assets dispatched

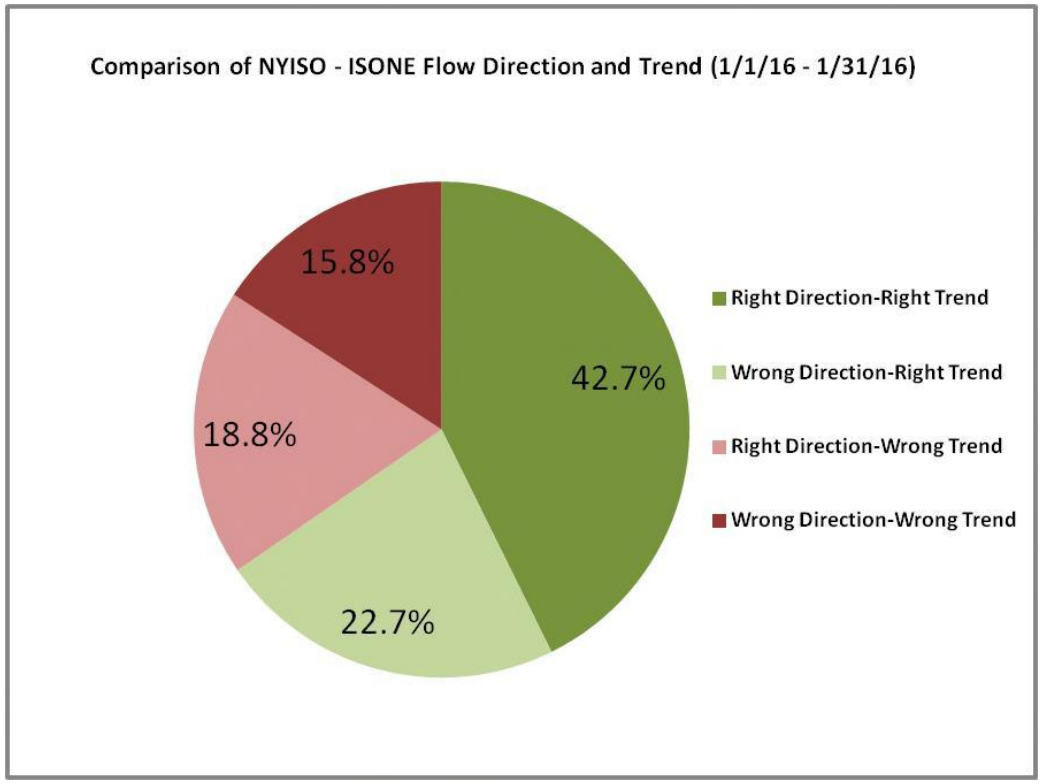
Winter Reliability Program Update

- 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 additional winter seasonal claimed capability represented: 1,774 MW
  - DFC Activity and related NCPC:
    - Units commissioned (as of Dec. 31): 5 successful, 1 outstanding
    - Total NCPC Commissioning Cap: $5.7M
      - 2014/15: $3.56M
      - 2015/16: $2.19M
    - NCPC incurred (through Jan. 25): $1.27M
    - Remaining Commissioning Cap for 2015/16: $0.3M

CTS Implementation: High Level Summary and Preliminary Observations

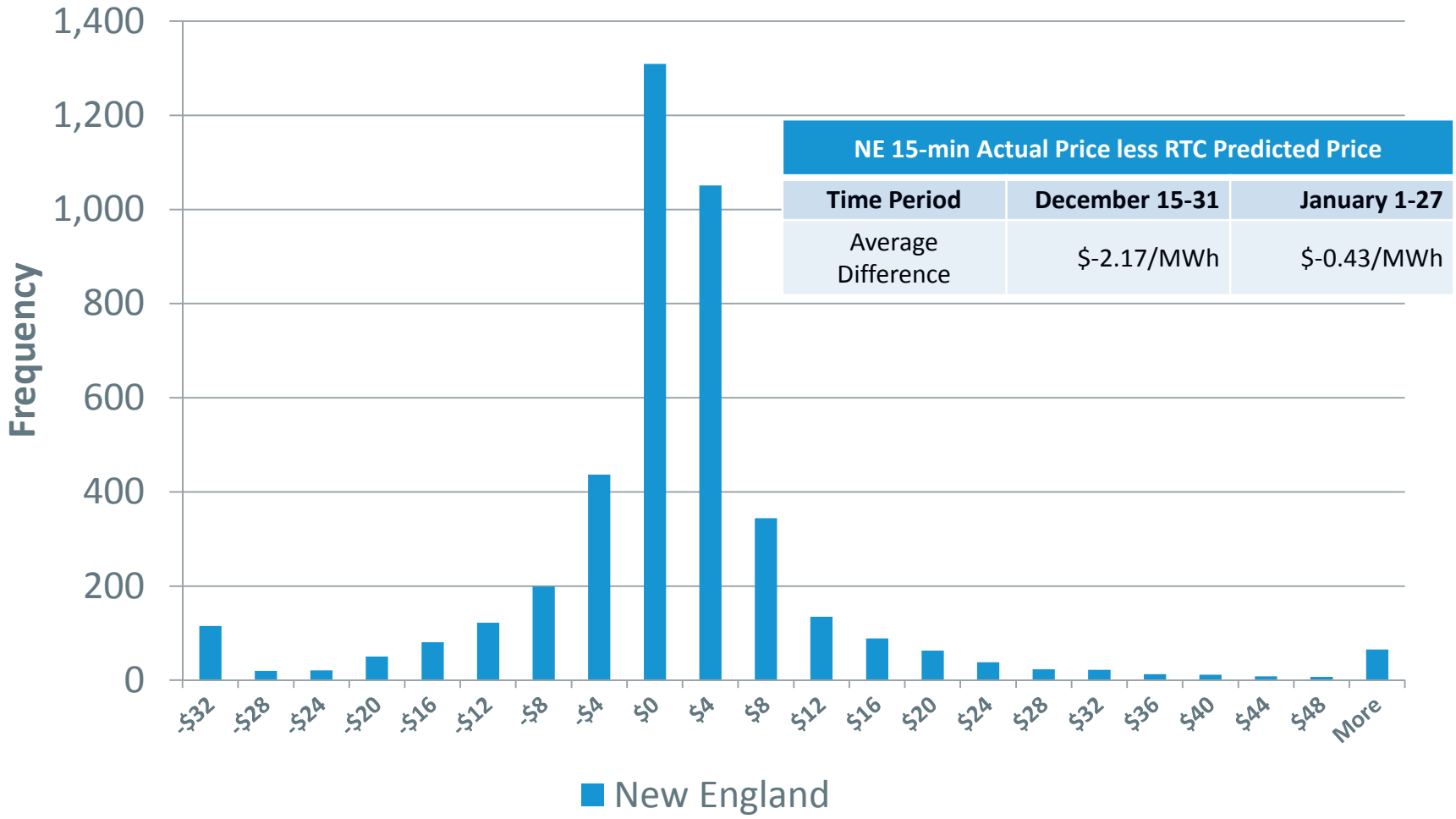
- Successful transition to use of CTS transactions on December 15, 2015
- Scheduled exports continue to be low compared to imports
  - Relatively few export bids compared with import bids
- Day-Ahead transactions continue to dominate the tie
- Energy flows consistent with regional prices have increased under CTS
- Conversations with participants suggest that activity will increase with experience

Energy Flow Direction/Trend in January 2016



- Right Direction indicates if flows are to the higher priced control area
- Right Trend indicates if flows are increasing over time intervals toward the higher priced control area
- Data uses a $2 tolerance between the NYISO and NE-ISO prices for measuring direction/trend
- Flows are either in the right direction/trend (or) right trend 65.4% of the time

Actual Minus Predicted LMPs for New England (Price Forecast Accuracy)



NE 15-min Actual Price less RTC Predicted Price		
Time Period	**December 15-31**	**January 1-27**
Average Difference	$-2.17/MWh	$-0.43/MWh

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (2.4°F) Max: 58°F, Min: 8°F Precipitation: 3.11" – Below Normal Snowfall: 5.51" Normal: 3.92"	Hartford	Temperature: Above Normal (3.0°F) Max: 59°F, Min: 5°F Precipitation: 1.96" – Below Normal Snowfall: 3.35" Normal: 3.84"

Peak Load:	19,412 MW	Jan 19, 2016	19:00 (ending)

MLCC2: 1/5/2015	Capacity Deficiency	Declared: 06:30 Cancelled: 19:10
OP-4 : None		

NPCC Simultaneous Activation of Reserve Events:

Date	Area	MW
1/5/16	NYISO	800
1/18/16	ISO-NE	580
1/23/16	NYISO	530
1/25/16	ISO-NE	1231

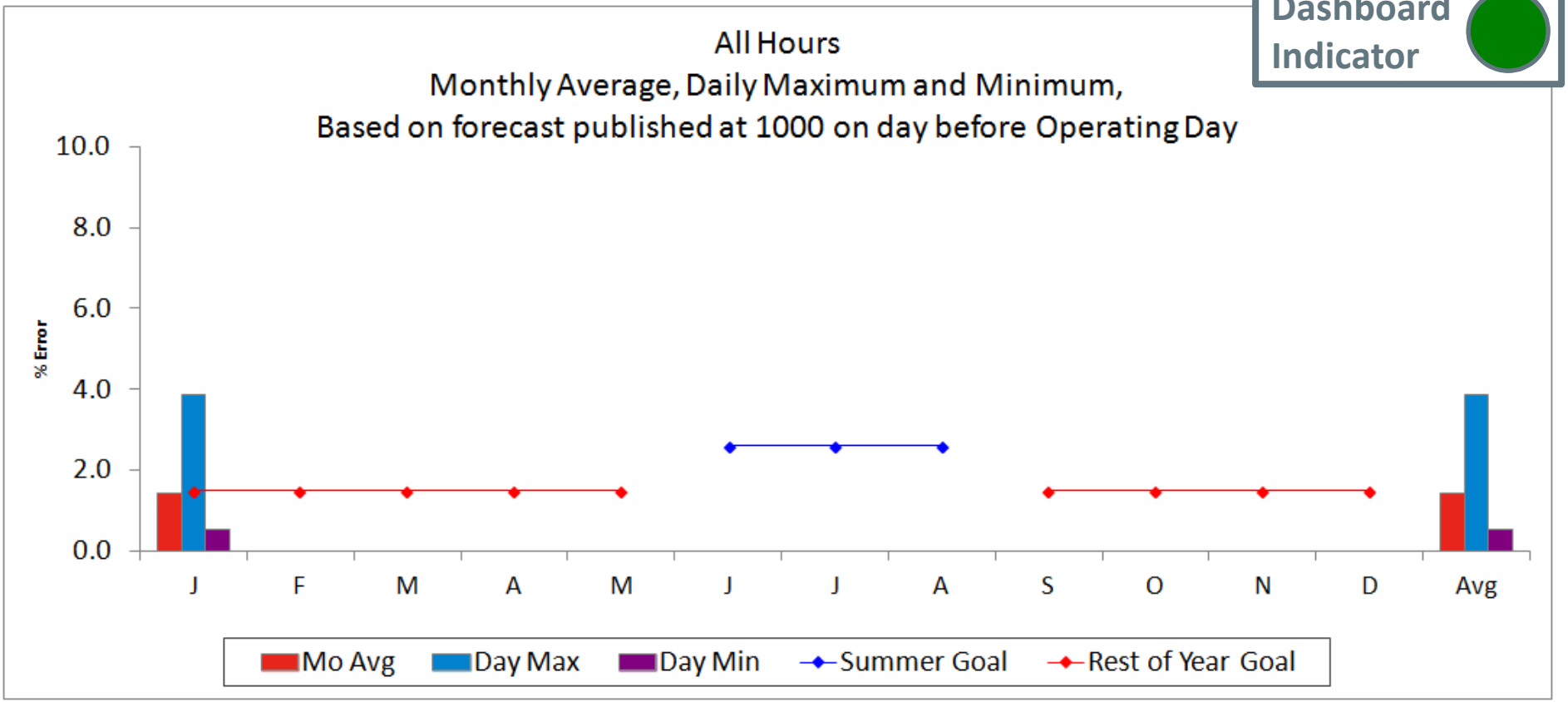
System Operations

Minimum Generation Warnings & Events:

Minimum Generation Warning	1/10/16, 23:00 – 1/11/16 07:00	Self Schedules Denied
Minimum Generation Warning	1/31/16, 23:00 – 2/1/16 06:00	Interchange cuts only

2016 System Operations - Load Forecast Accuracy

Dashboard Indicator

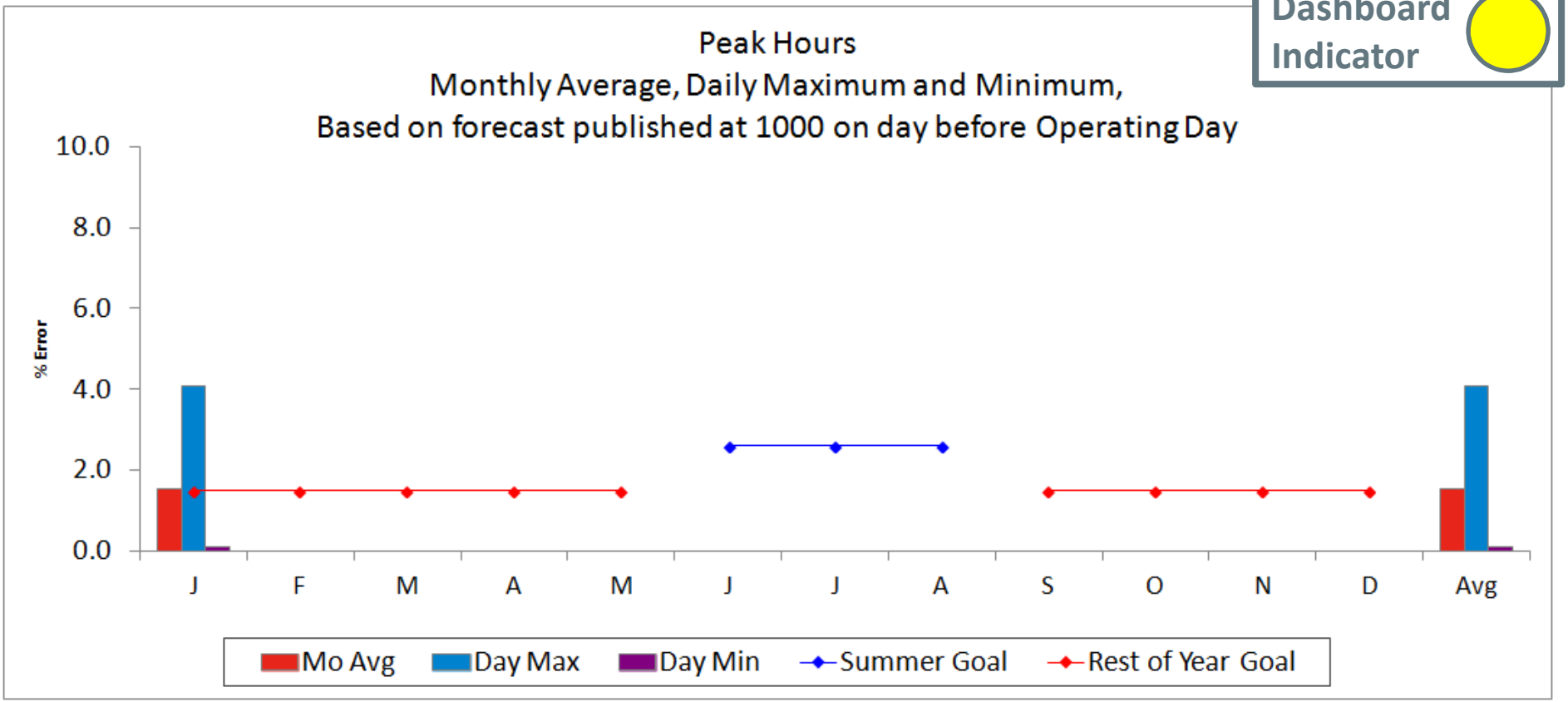


Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.44												1.44
Day Max	3.88												3.88
Day Min	0.54												0.54
Summer Goal						2.60	2.60	2.60					
Rest of Year Goal	1.50	1.50	1.50	1.50	1.50				1.50	1.50	1.50	1.50	
Rest of Year Actual	1.44												1.44
Summer Actual													

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

2016 System Operations - Load Forecast Accuracy cont.

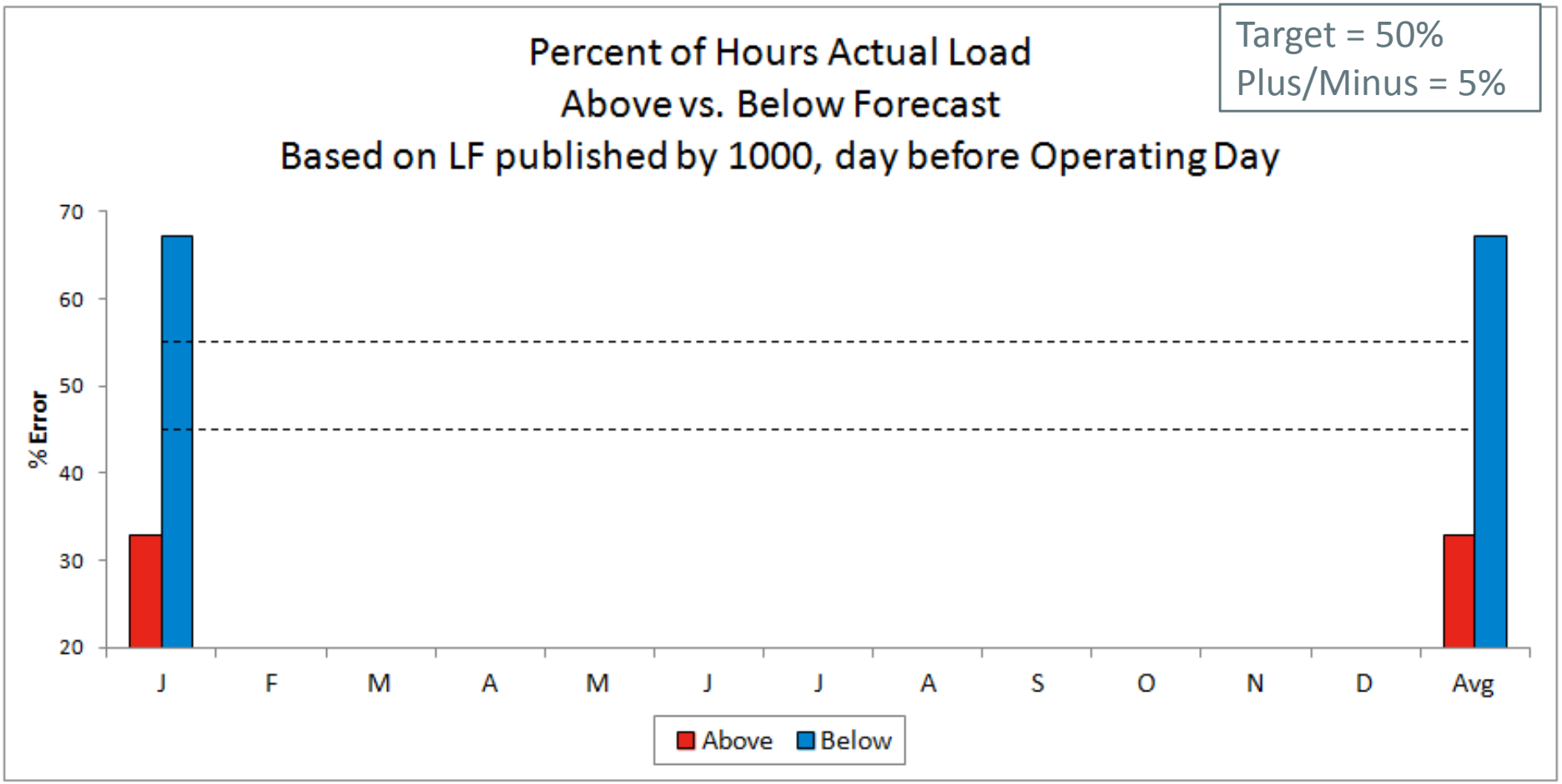
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Mo Avg	1.55												1.55
Day Max	4.10												4.10
Day Min	0.09												0.09
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	1.55												1.55
Summer Actual													

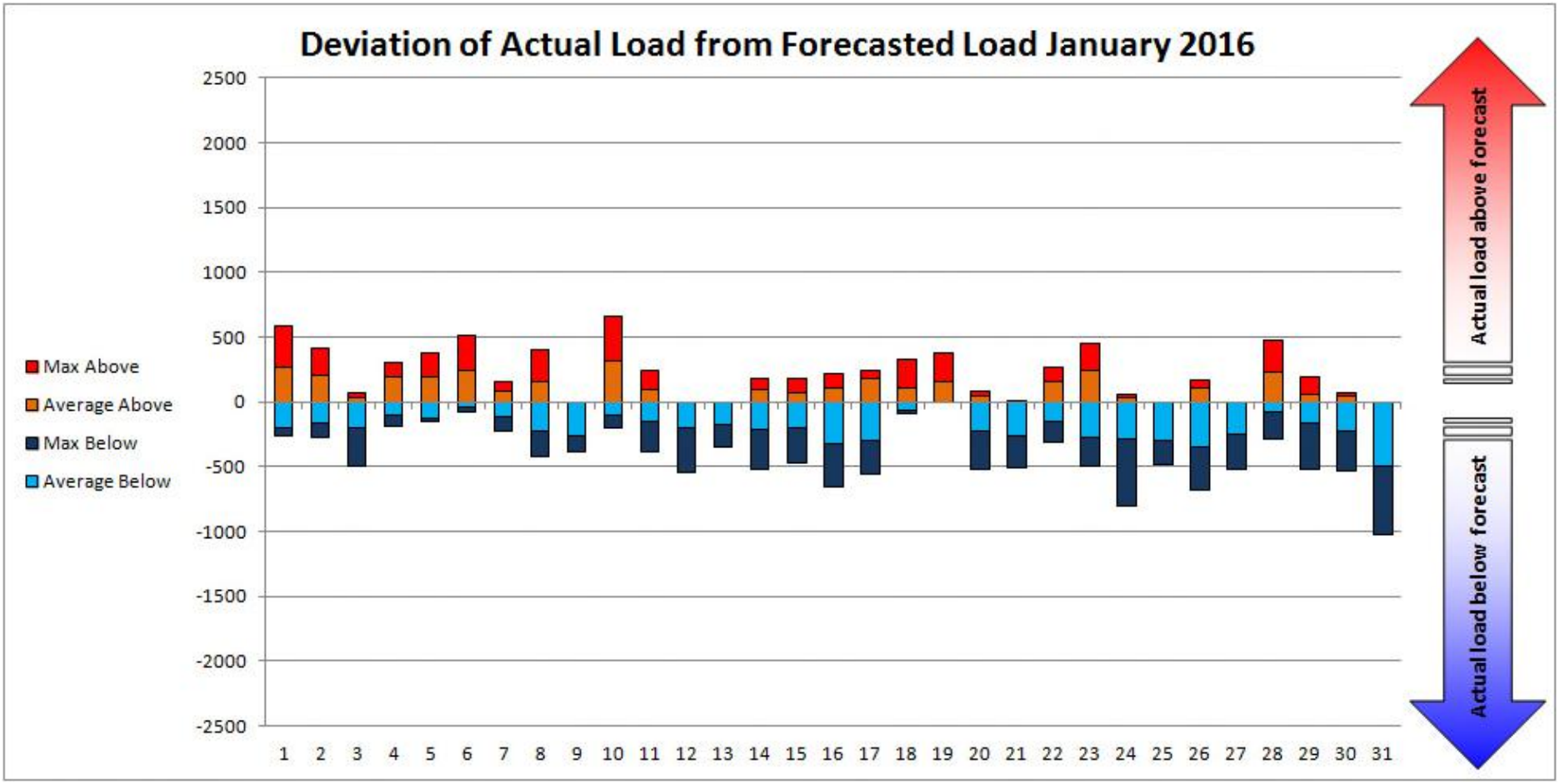
Rest of Year Goal < 1.5%
Summer Goal < 2.6%

2016 System Operations - Load Forecast Accuracy cont.

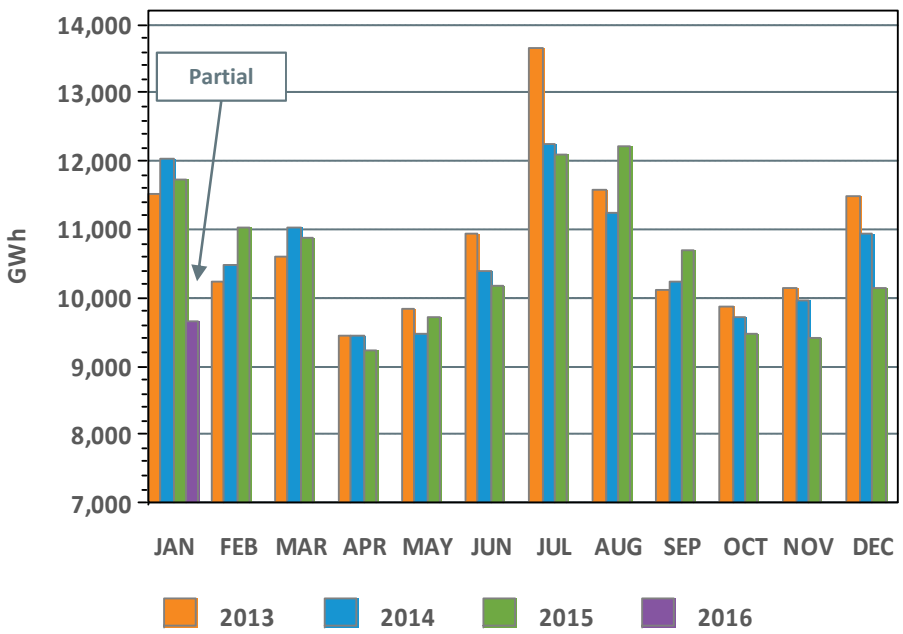


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	32.9												33
Below %	67.1												67
Avg Above	109.8												110
Avg Below	-200.6												-201
Avg All	-100												-100

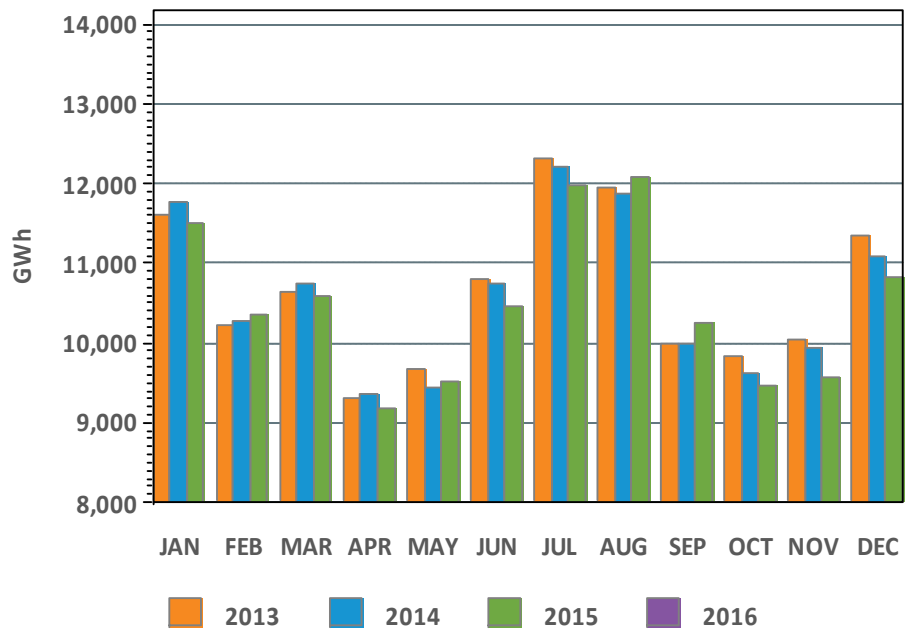
2016 System Operations - Load Forecast Accuracy cont.



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



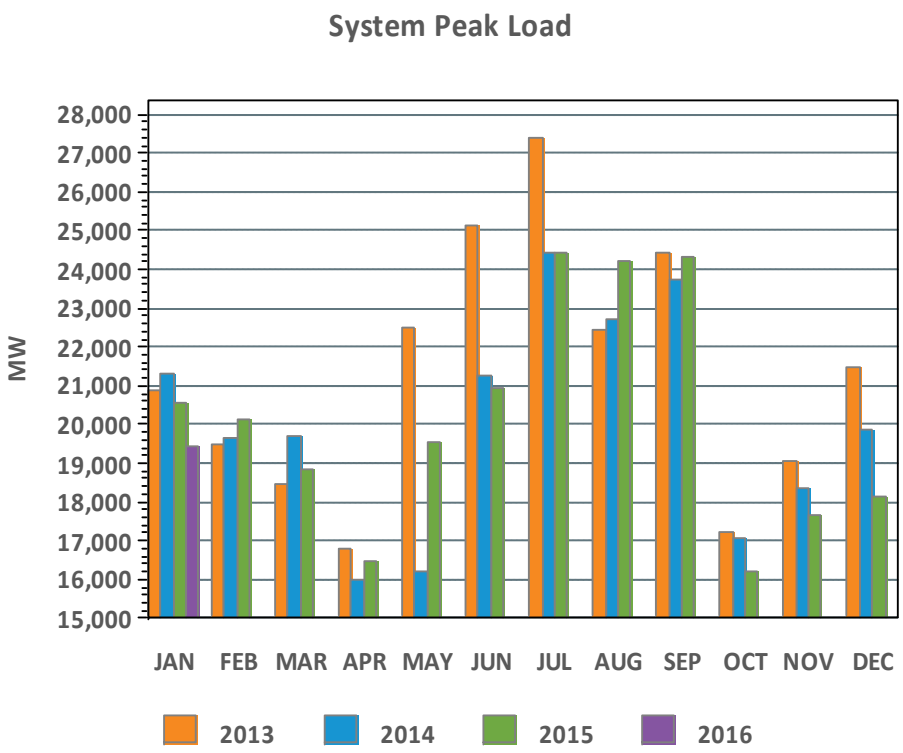
Ann Tot (TWh): 129.4 127.2 126.8 9.7

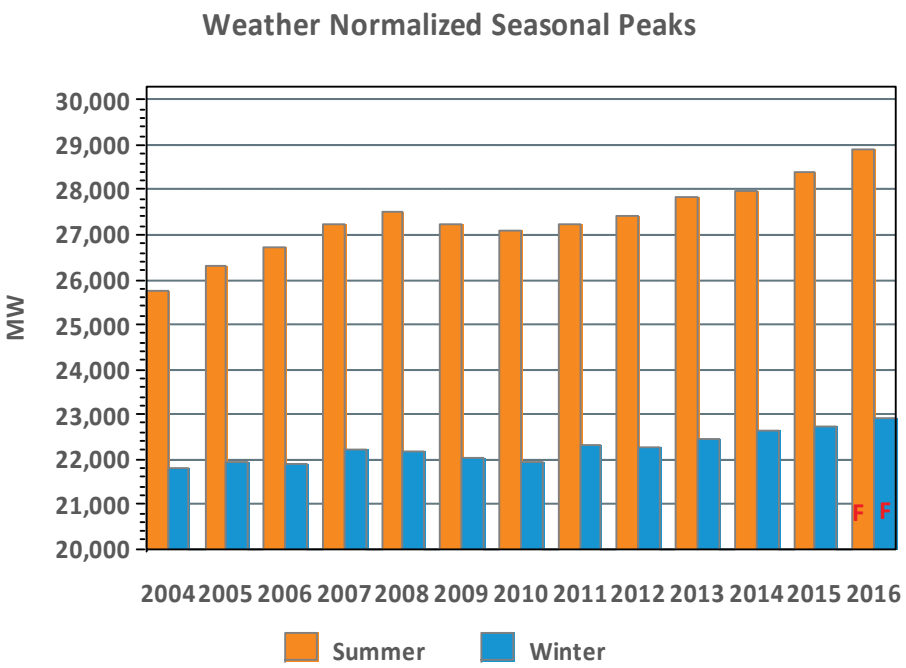


Ann Tot (TWh): 127.8 127.1 125.8 .

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



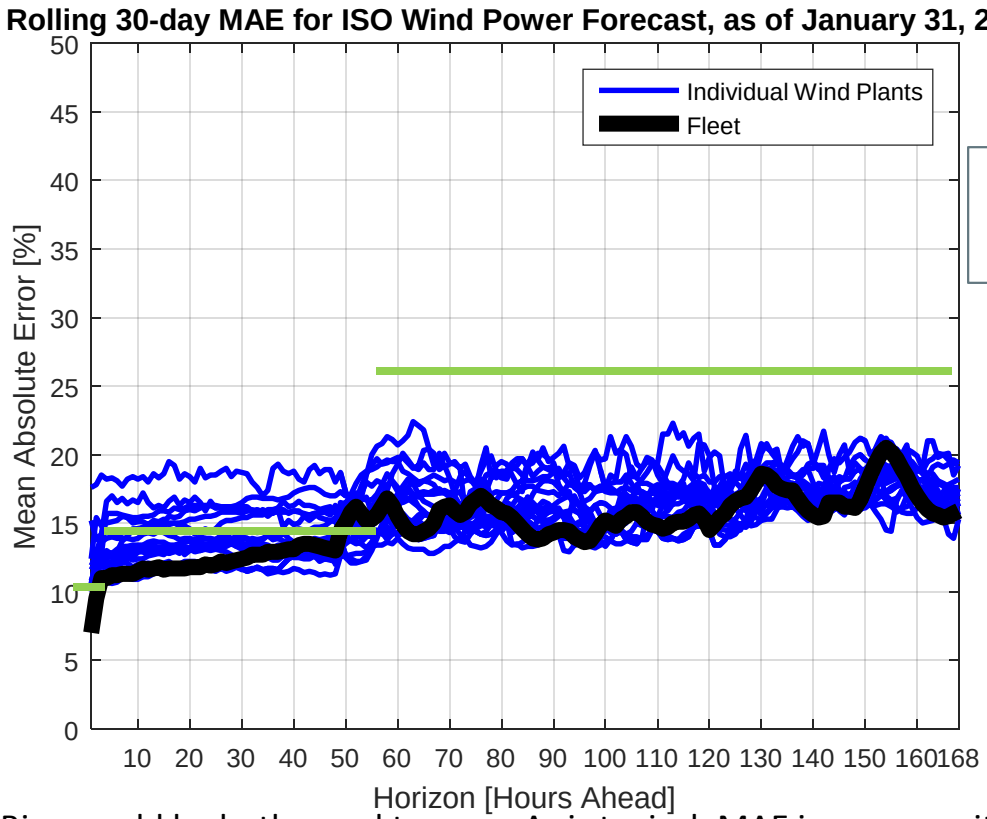


Winter beginning in year displayed

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

Wind Power Forecast Error Statistics: MAE

Dashboard Indicator

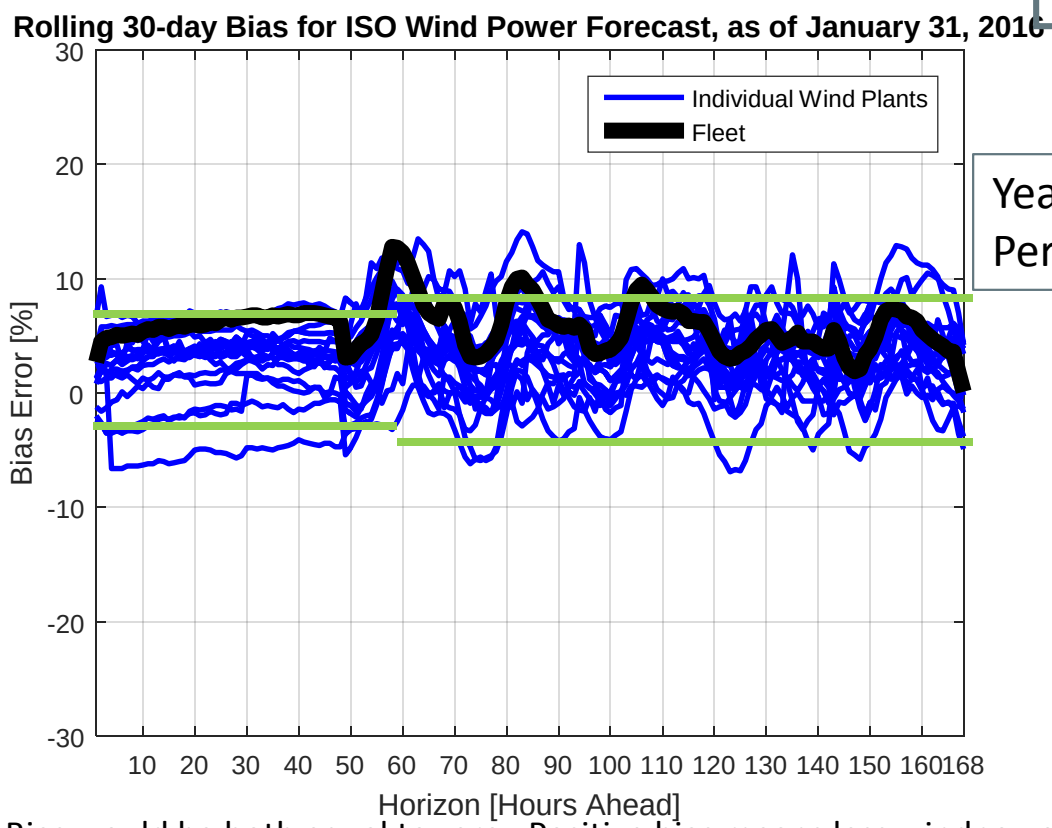


Yearly Fleet Performance targets

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 monthly MAE continues to be well within the yearly performance targets specified in the forecast RFP.

Wind Power Forecast Error Statistics: Bias

Dashboard Indicator

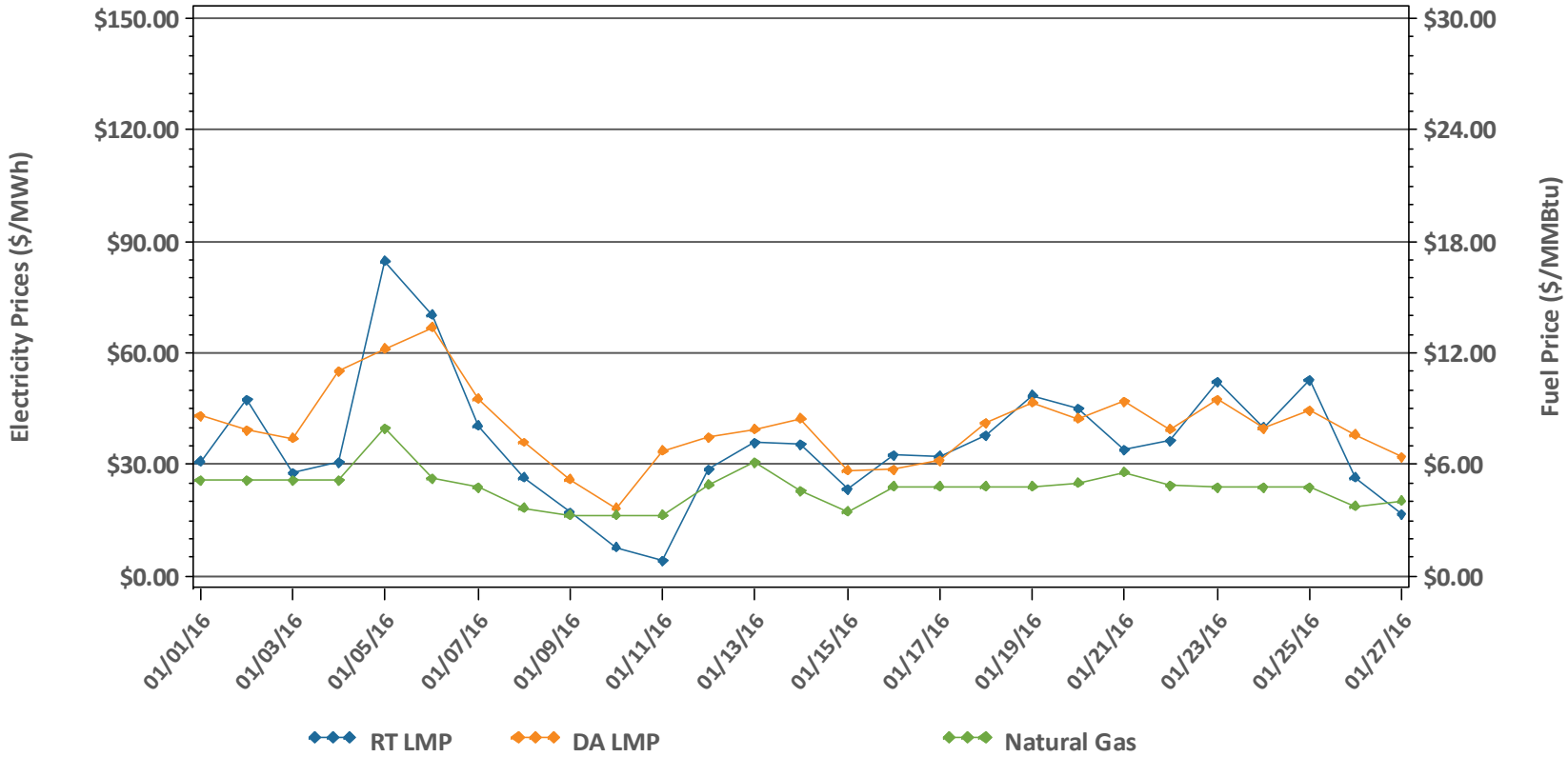


Yearly Fleet Performance targets

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 January's monthly values 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: January 1-27, 2016

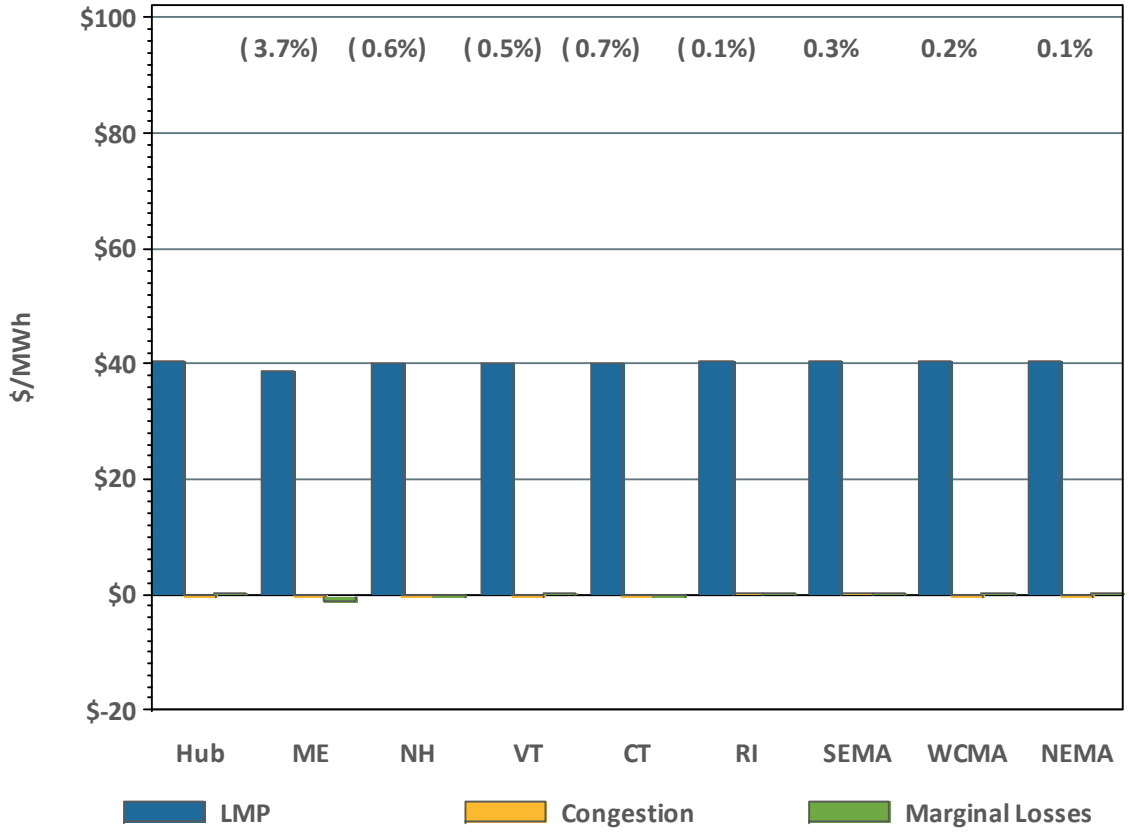


Underlying natural gas data furnished by:

ICE Global markets in clear view

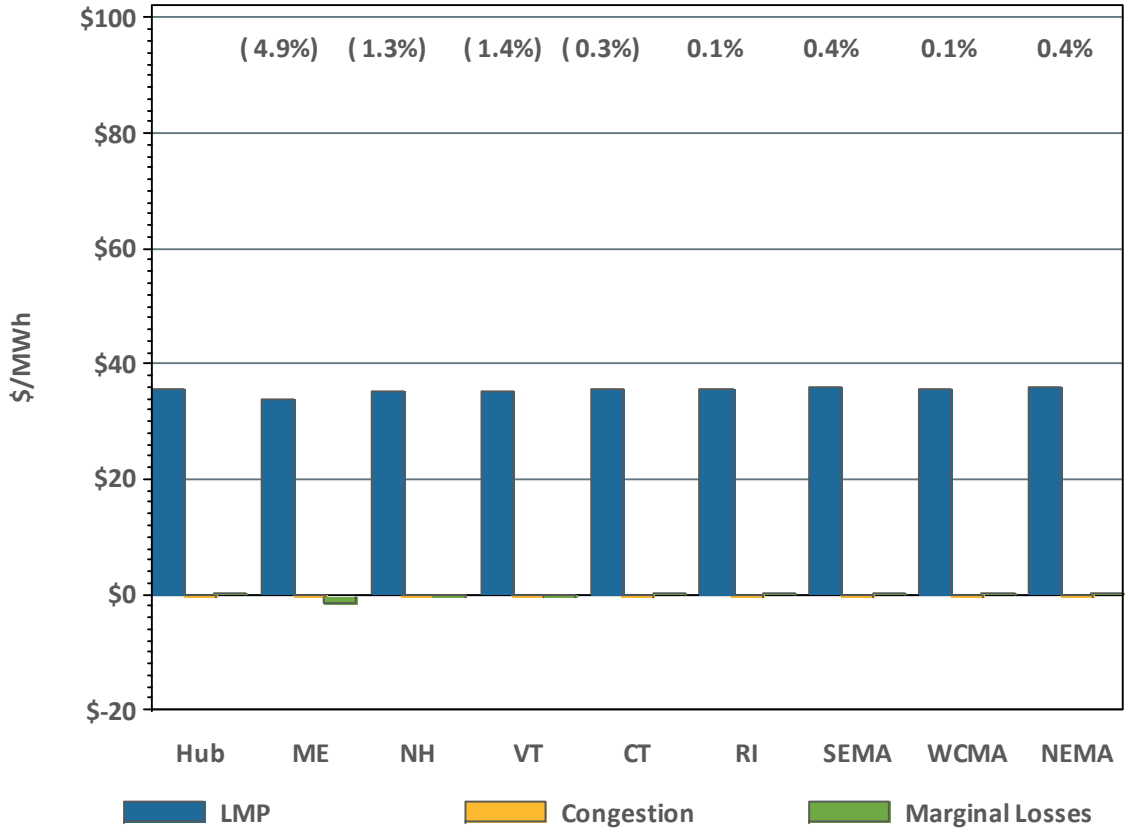
Average price difference over this period (DA-RT): $4.63
Average price difference over this period ABS(DA-RT): $8.91
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 25%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, January 2016



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

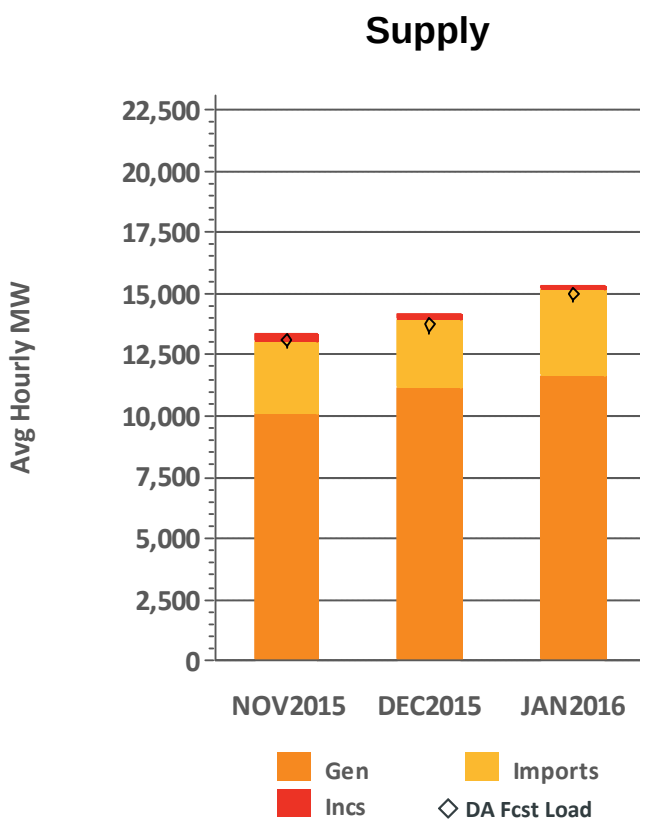
RT LMPs Average by Zone & Hub, January 2016



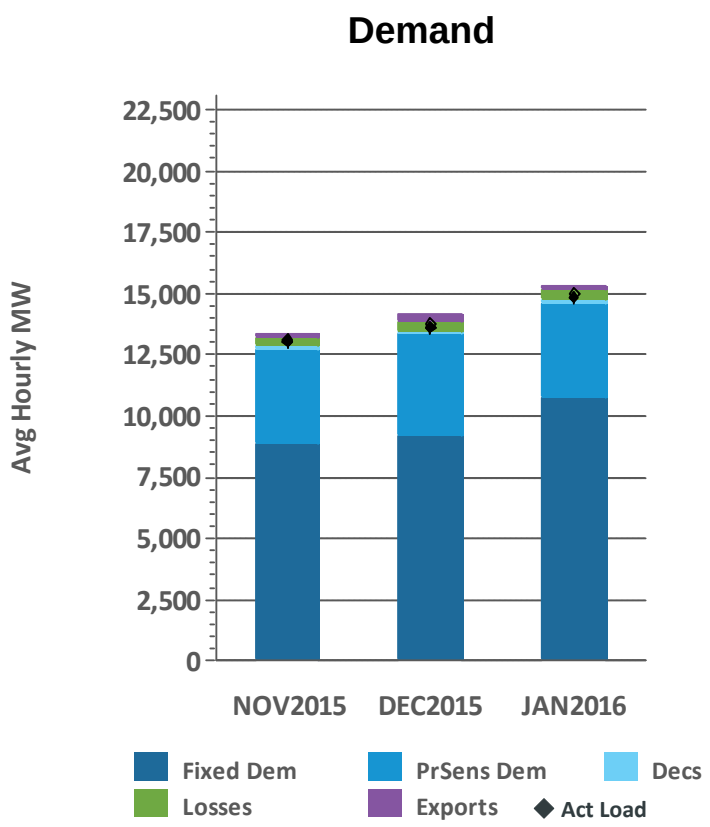
Definitions

Day-Ahead Concept	Definition
Day-Ahead Load Obligation **(DALO)**	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

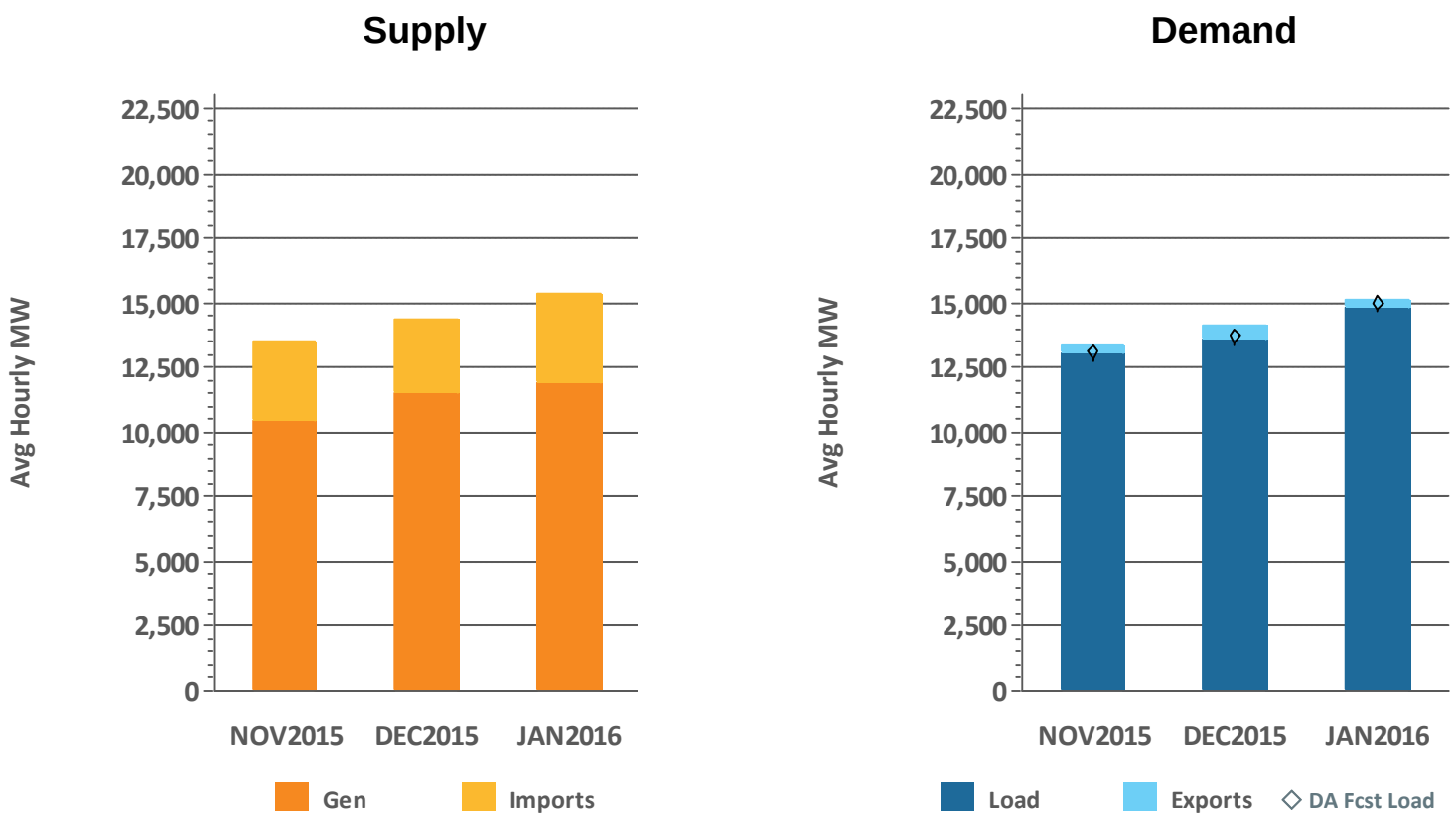


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

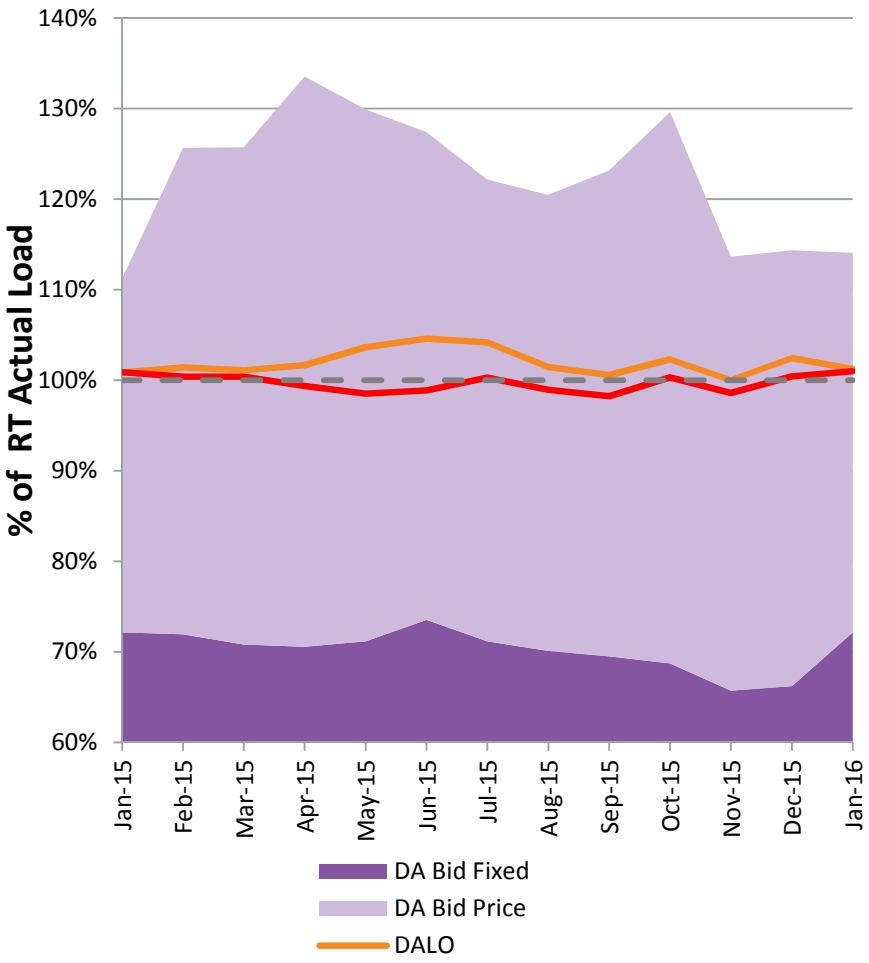


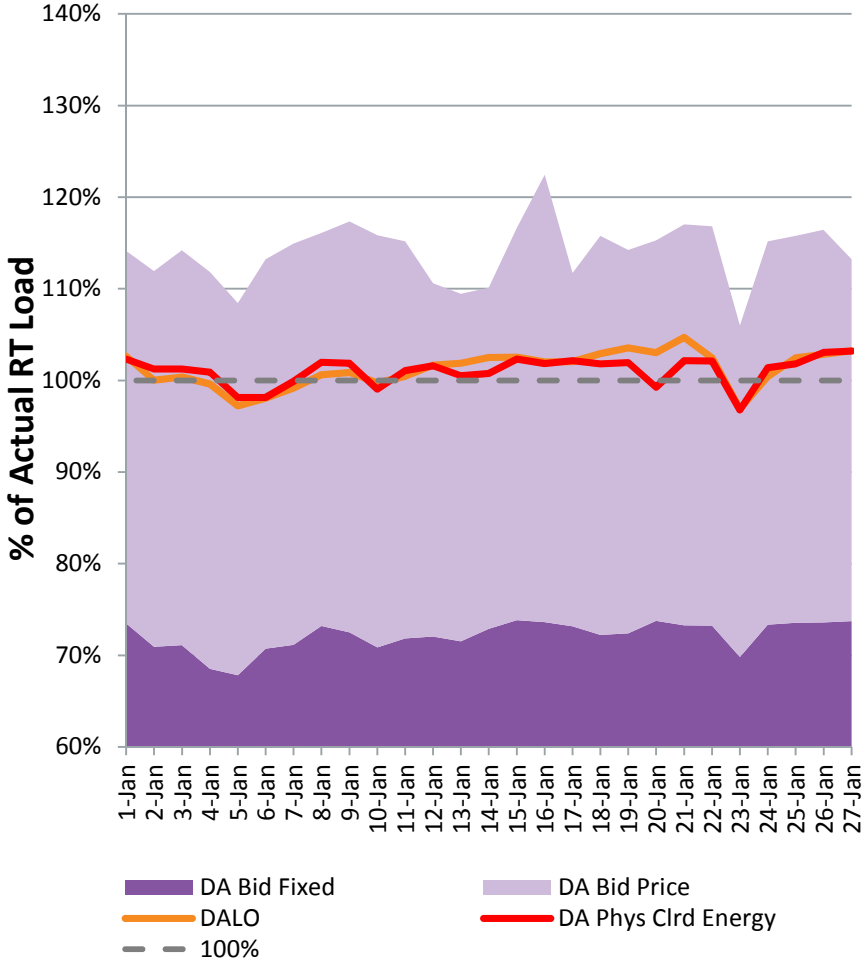
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months



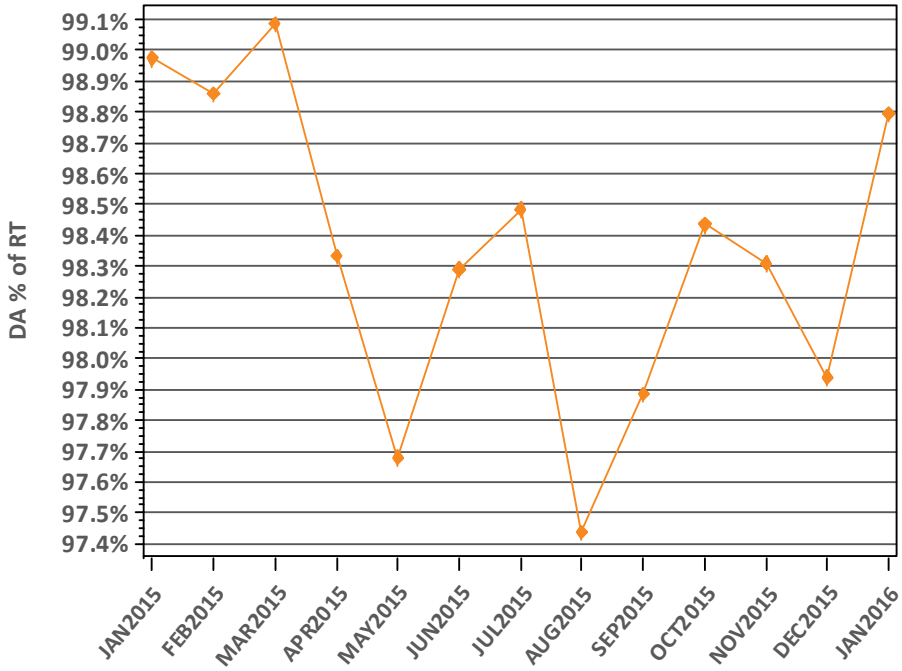
DAM Volumes vs. RT Actual Load (Peak Hour): Monthly and Daily

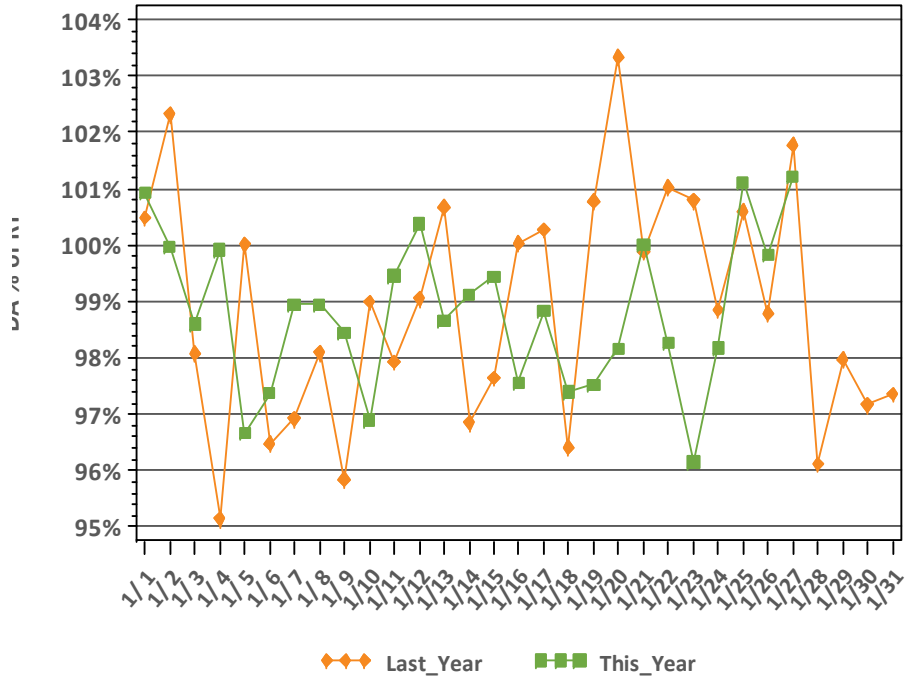




Note: Percentages were derived for the peak hour of each day (shown on right), then averaged over the month (shown on left). Values at hour of forecasted peak load.

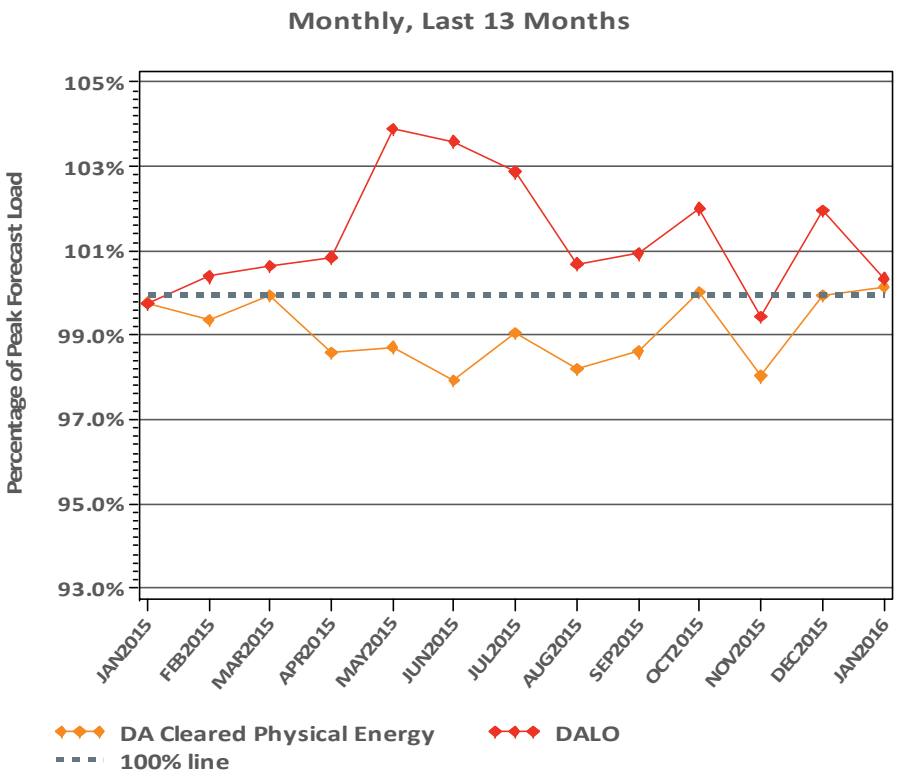
DA vs. RT Load Obligation: January, This Year vs. Last Year

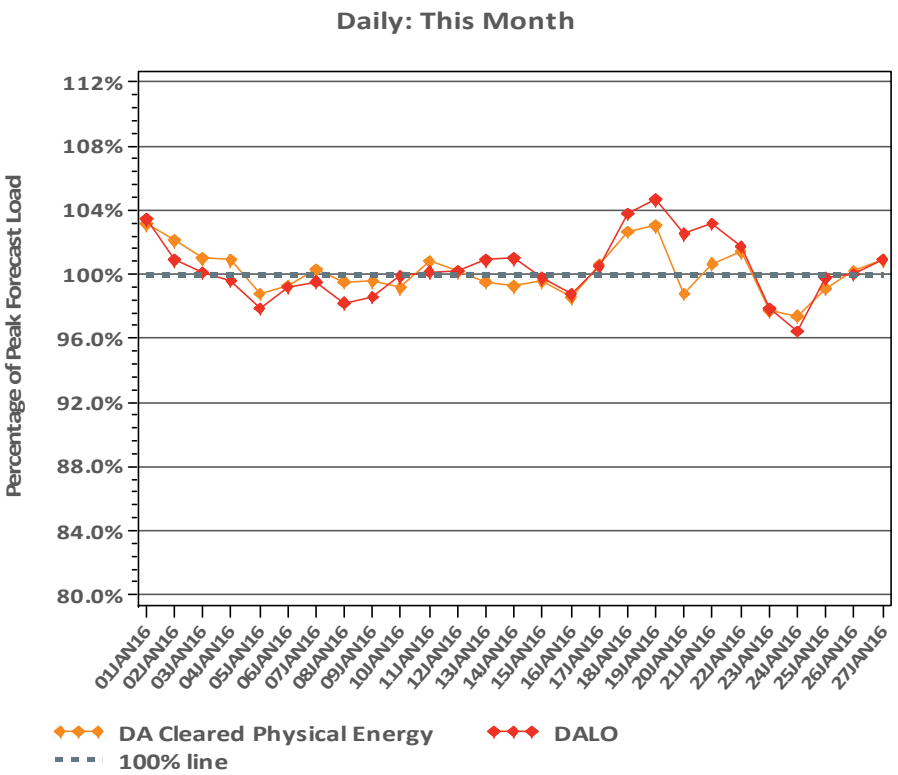




*Hourly average values

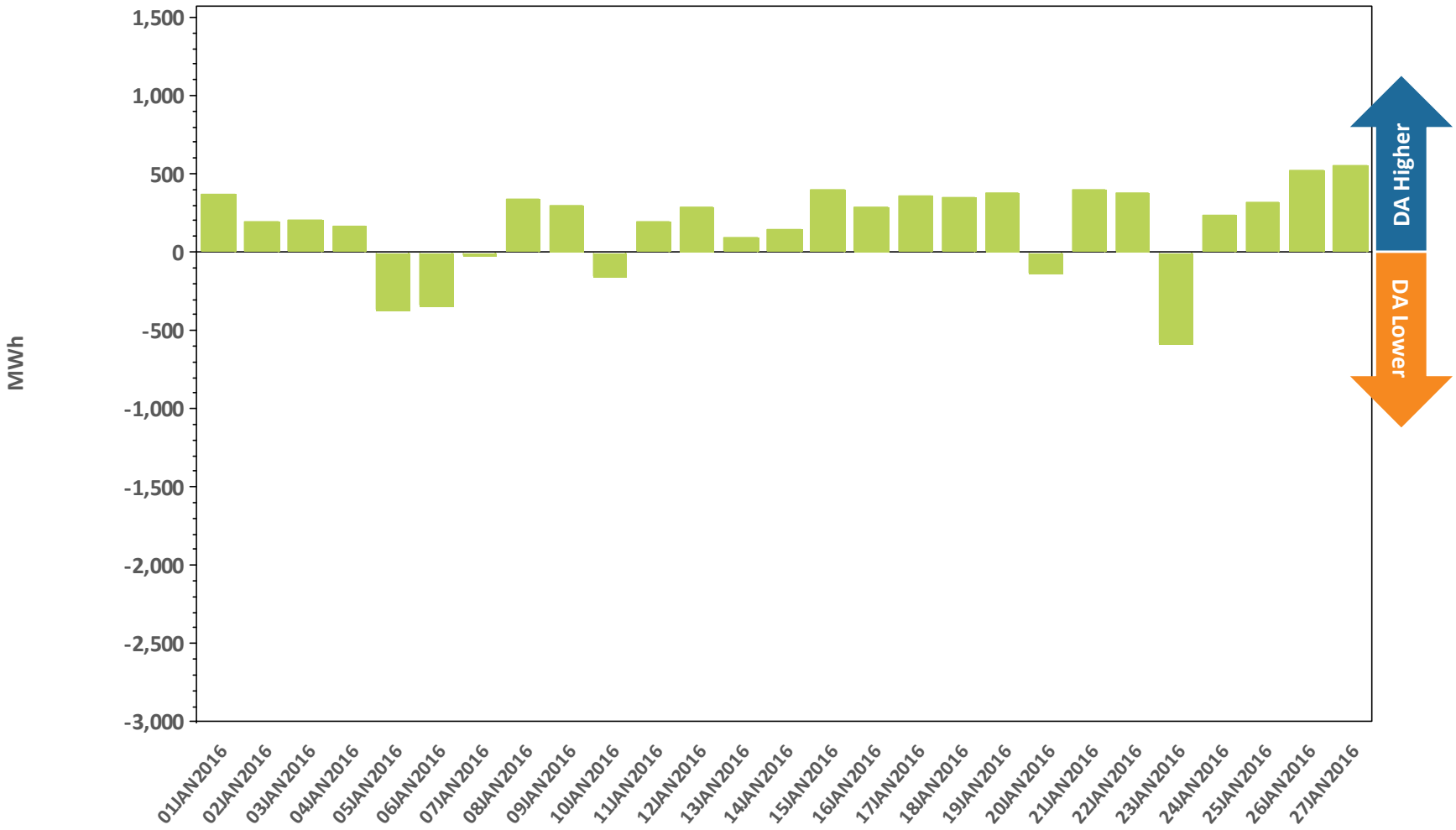
DA Volumes as % of Forecast (Peak Hour)





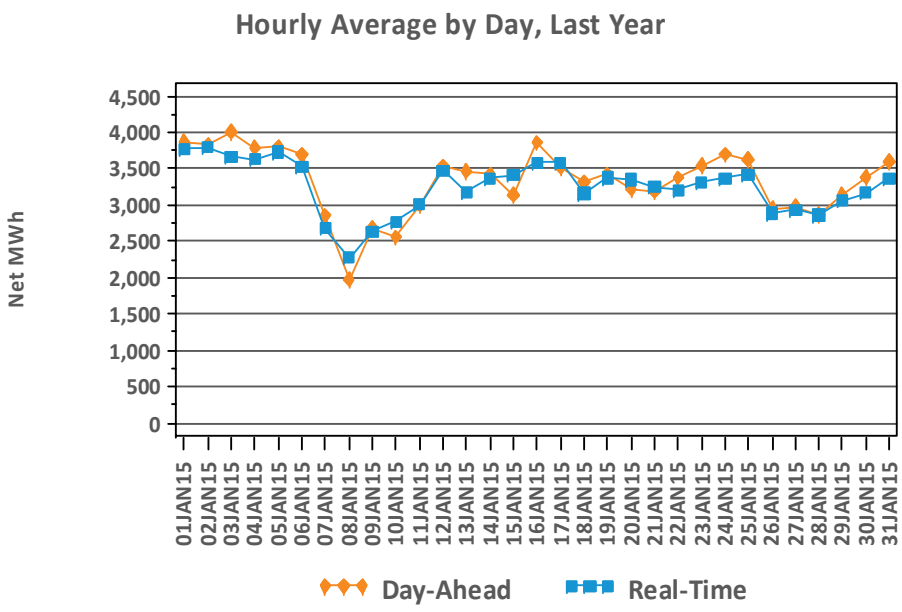
*Forecasted peak hour is reflected.

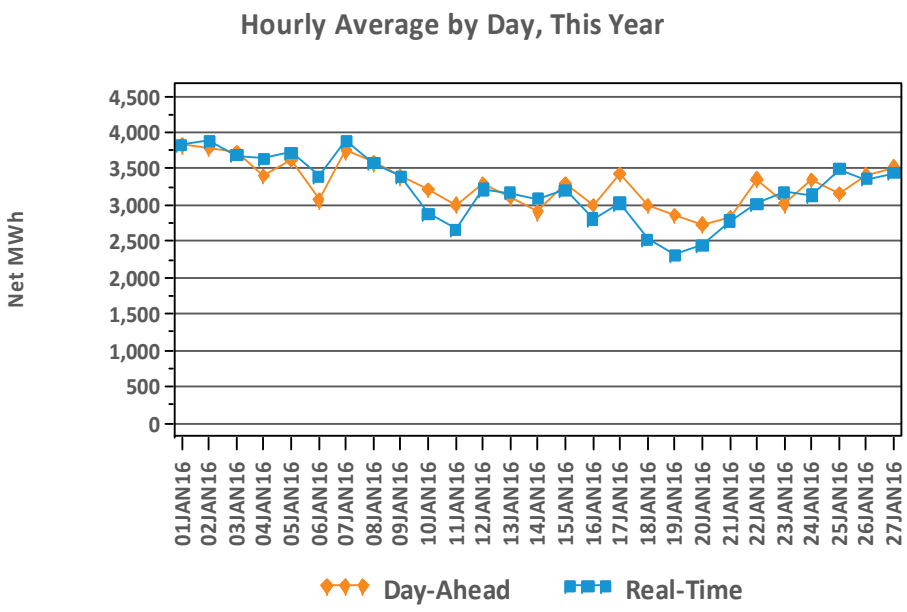
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

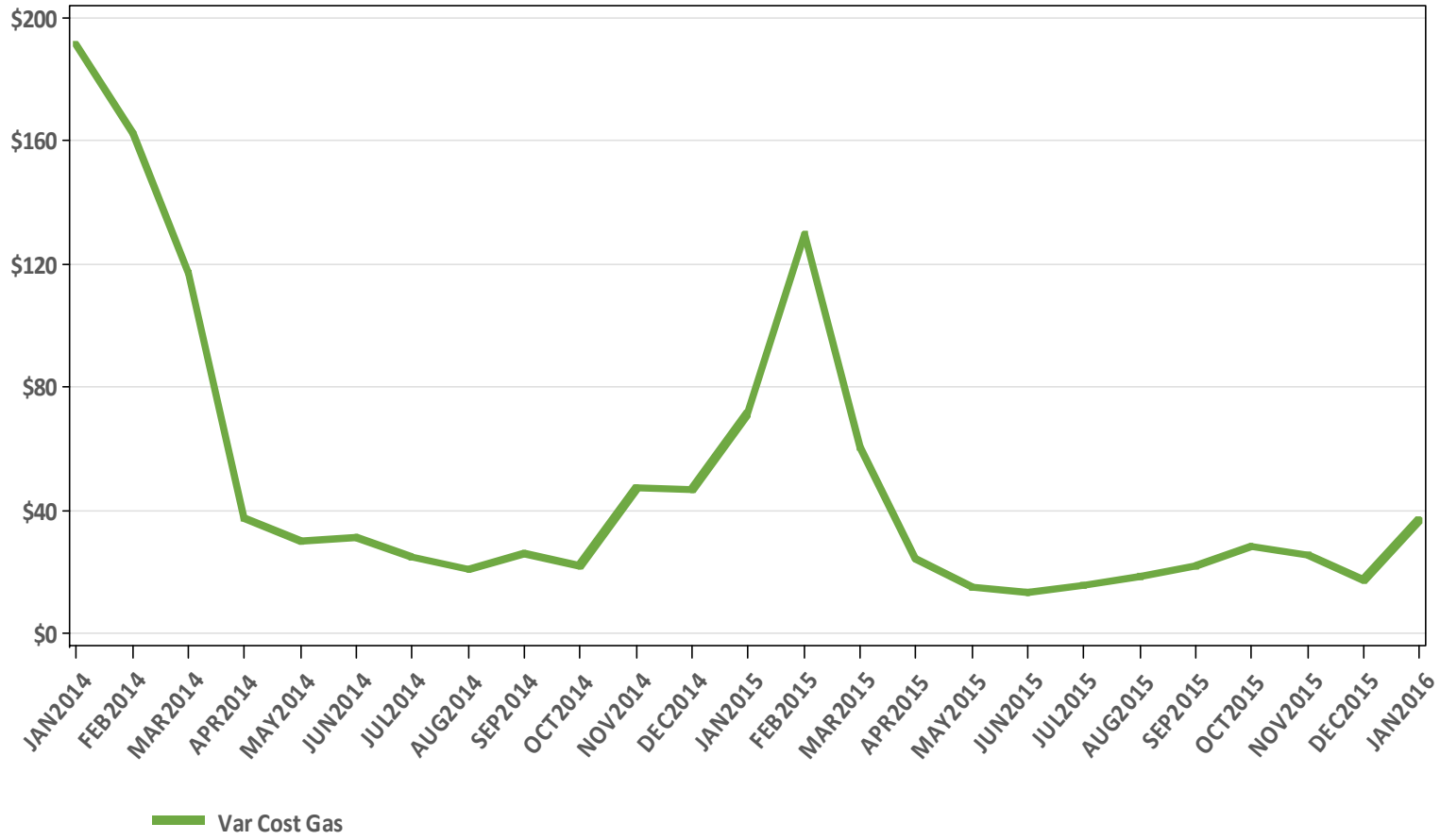
DA vs. RT Net Interchange
January 2016 vs. January 2015





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

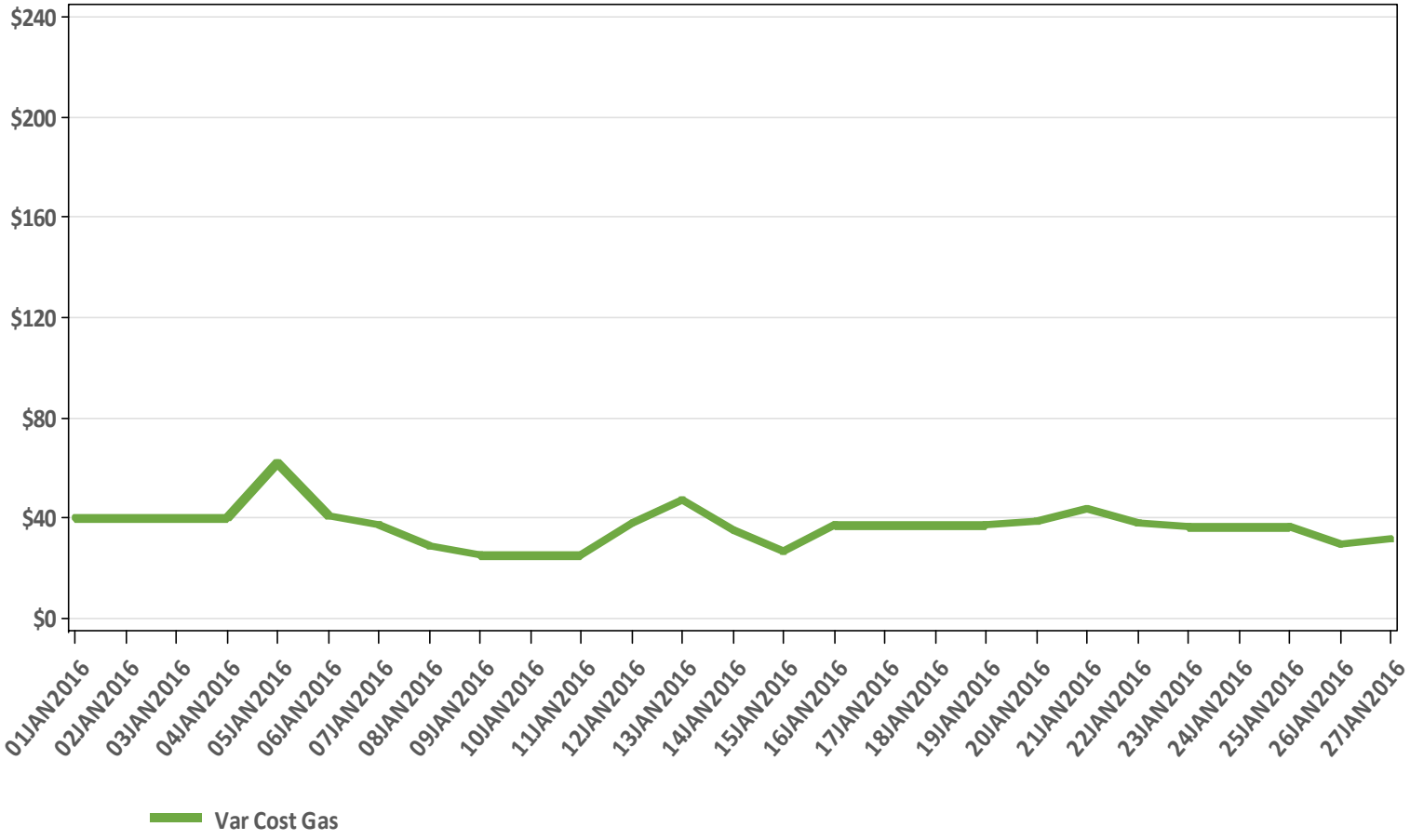


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:

ICE Global markets in clear view

Variable Production Cost of Natural Gas: Daily

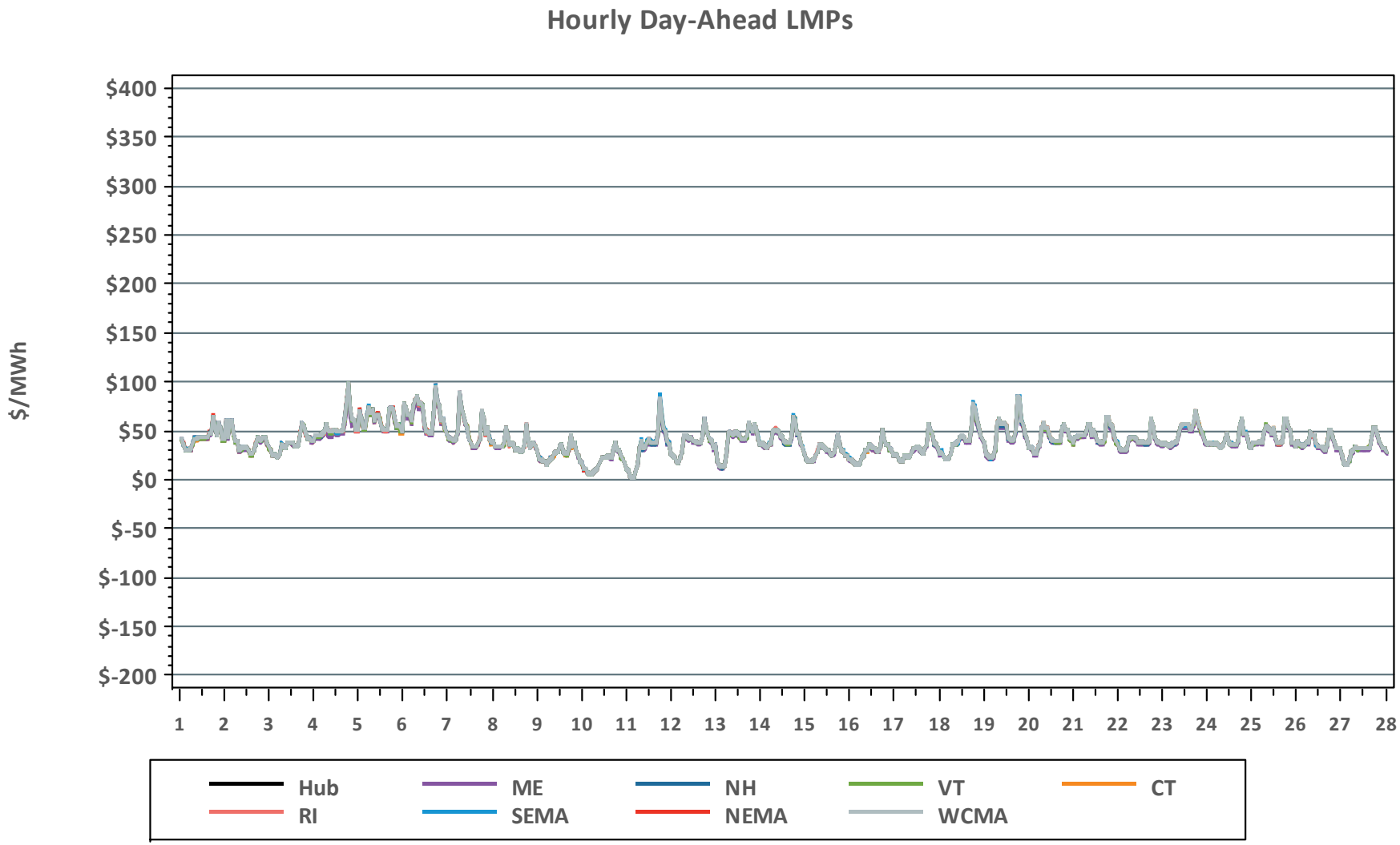


Underlying natural gas data furnished by:

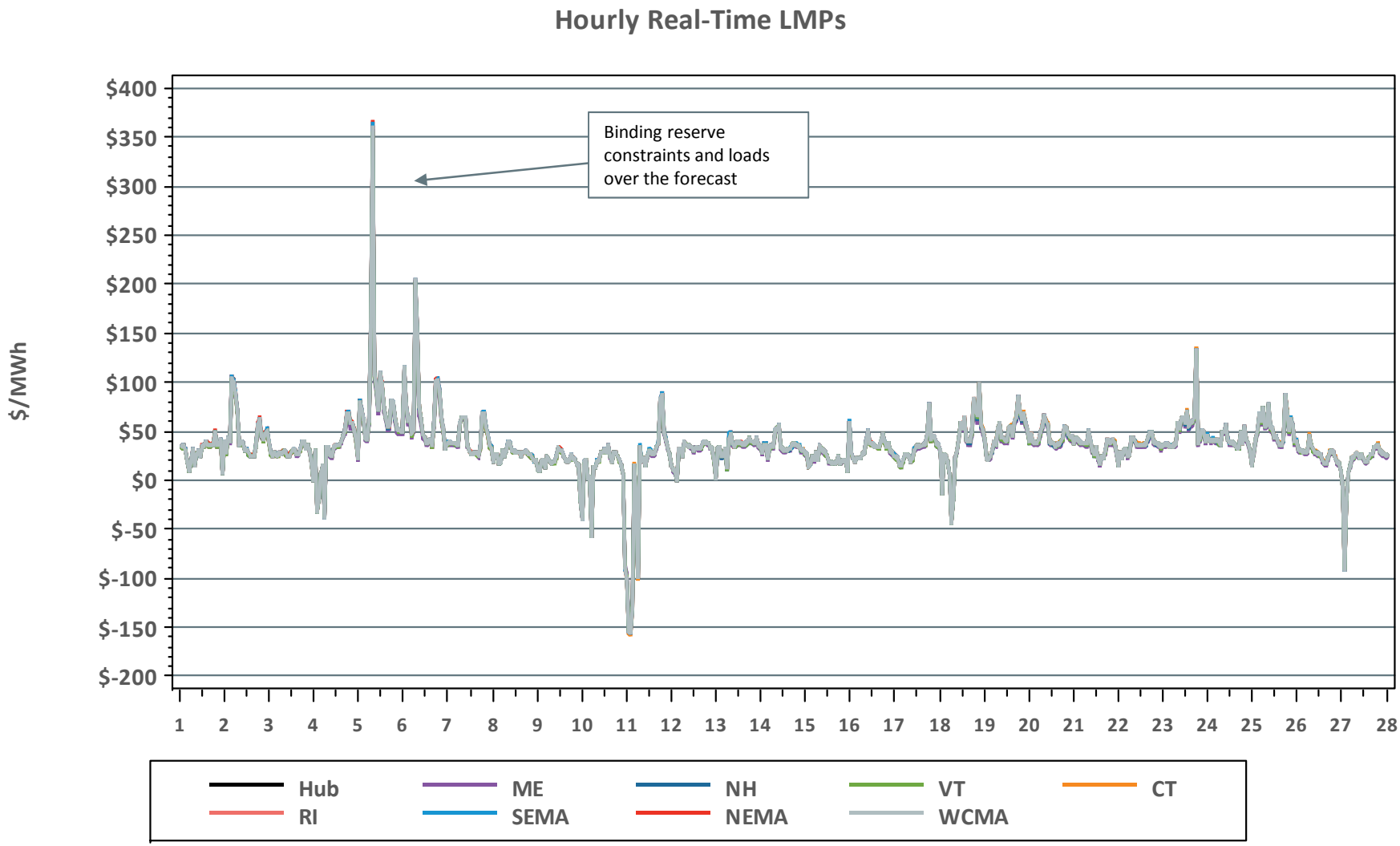
ICE Global markets in clear view

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

Hourly DA LMPs, January 1-27, 2016

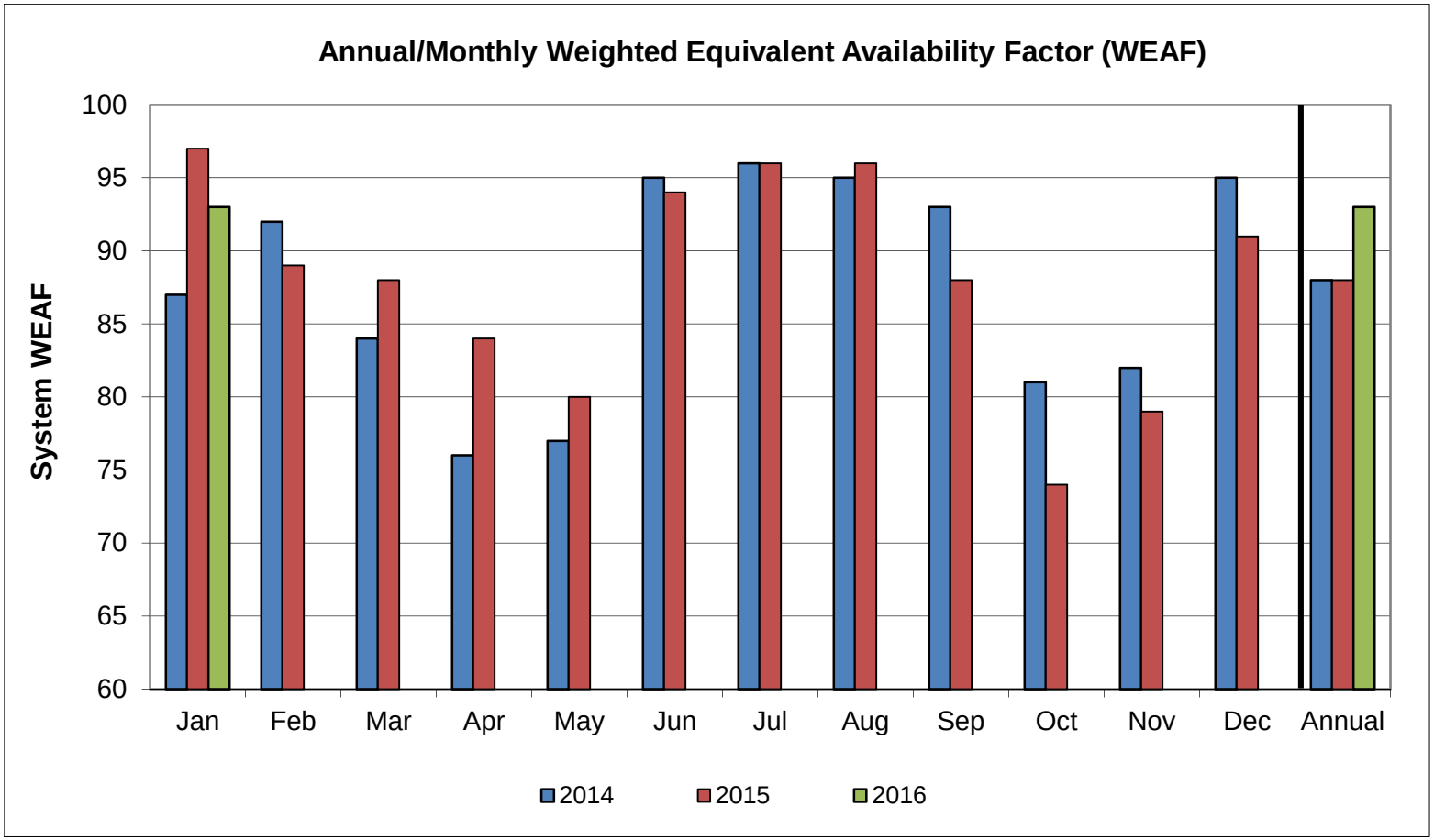


Hourly RT LMPs, January 1-27, 2016



There were no Min. Gen. Emergencies in January

System Unit Availability



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2016	93												93
2015	97	89	88	84	79	94	96	96	88	74	79	91	88
2014	87	92	84	76	77	95	96	95	93	81	82	95	88
2013	89	87	85	76	81	90	90	92	88	80	81	92	86

Data as of 2/1/16

BACK-UP DETAIL

LOAD RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for February 2016

Load Zone	RTDR*	RTEG**	On Peak	Seasonal Peak	Total
ME	103.2	3.4	118.5	0.0	225.1
NH	6.4	11.9	78.6	0.0	97.0
VT	31.5	2.5	104.9	0.0	138.9
CT	67.3	78.6	71.5	310.7	528.1
RI	10.7	11.5	157.8	0.0	180.0
SEMA	5.4	8.8	209.5	0.0	223.7
WCMA	22.9	19.6	205.7	44.6	292.7
NEMA	30.2	5.8	372.9	0.0	408.9
Total	**277.6**	**142.1**	**1,319.5**	**355.3**	**2,094.4**

*** 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

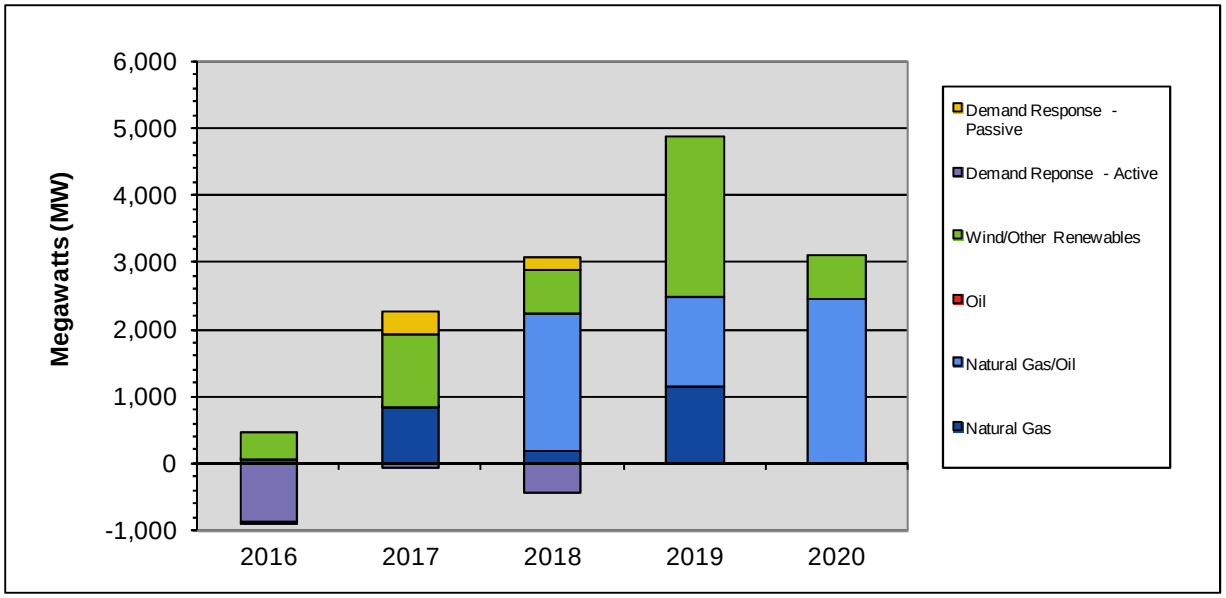
New Generation Update

Based on Queue as of 2/1/16

- Four new projects, with a total rating of 266 MW, have applied for interconnection study since the last update
  - The projects consist of one steam turbine increase, two new photovoltaic plants, and one pumped storage upgrade. The expected in-service dates range from 2016 to 2020.
- One project went commercial, resulting in a net increase in new generation projects of 254 MW
- In total, 90 generation projects are currently being tracked by the ISO, totaling approximately 13,300 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



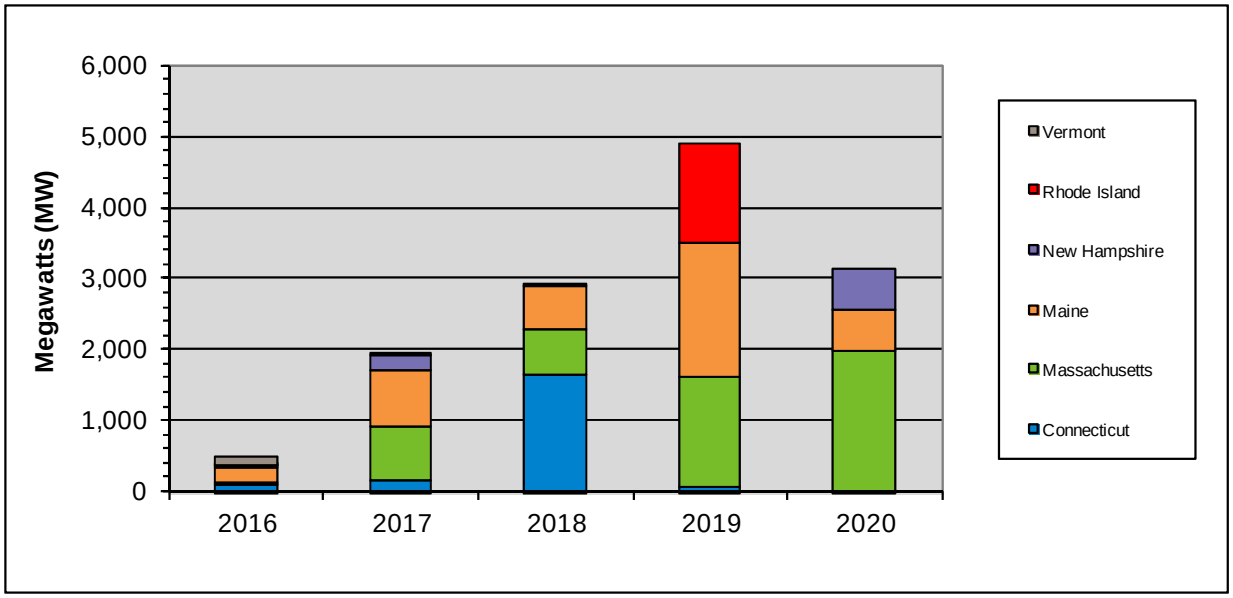
	2016	2017	2018	2019	2020	Total MW	% of Total[1]
Demand Response - Passive	-12	330	196	0	0	513	4.1
Demand Response - Active	-868	-37	-433	0	0	-1,338	-10.7
Wind & Other Renewables	402	1,100	644	2,396	667	5,209	41.6
Oil	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	10	14	2,044	1,335	2,460	5,863	46.8
Natural Gas	72	837	210	1,149	0	2,268	18.1
Totals	**-396**	**2,244**	**2,661**	**4,880**	**3,127**	**12,515**	**100.0**

[1] Sum may not equal 100% due to rounding

[2] The projects in this category are dual fuel, with either gas or oil as the primary fuel

- 2016 values include the 12 MW of generation that has gone commercial in 2016
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions
By State



	2016	2017	2018	2019	2020	Total MW	% of Total[1]
Vermont	117	0	30	0	0	147	1.1
Rhode Island	22	29	0	1,387	0	1,438	10.8
New Hampshire	31	218	0	0	570	819	6.1
Maine	188	789	607	1,879	601	4,064	30.5
Massachusetts	56	766	630	1,551	1,956	4,959	37.2
Connecticut	70	149	1,631	63	0	1,913	14.3
Totals	**484**	**1,951**	**2,898**	**4,880**	**3,127**	**13,340**	**100.0**

[1] Sum may not equal 100% due to rounding

- 2016 values reflect the 12 MW of generation that has gone commercial in 2016

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	2	41	0	0	2	41
Hydro	4	99	0	0	4	99
Landfill Gas	1	2	0	0	1	2
Natural Gas	14	2,331	0	0	14	2,331
Natural Gas/Oil	18	5,863	0	0	18	5,863
Oil	0	0	0	0	0	0
Solar	15	627	5	90	10	537
Wind	33	4,272	5	317	28	3,955
Battery Storage	3	93	0	0	3	93
Total	90	13,328	10	407	80	12,921

- 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	4	106	0	0	4	106
Intermediate	23	6,956	0	0	23	6,956
Peaker	30	1,994	5	90	25	1,904
Wind Turbine	33	4,272	5	317	28	3,955
Total	90	13,328	10	407	80	12,921

- 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	2	41	2	41	0	0	0	0	0	0
Hydro	4	99	0	0	2	8	2	91	0	0
Landfill Gas	1	2	1	2	0	0	0	0	0	0
Natural Gas	14	2,331	1	63	10	2,070	3	198	0	0
Natural Gas/Oil	18	5,863	0	0	11	4,878	7	985	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	15	627	0	0	0	0	15	627	0	0
Wind	33	4,272	0	0	0	0	0	0	33	4,272
Battery Storage	3	93	0	0	0	0	3	93	0	0
Total	90	13,328	4	106	23	6,956	30	1,994	33	4,272

- 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
Demand Total		**3,644.844**	**3,471.716**	**-173.128**	**2,890.143**	**-581.573**	**2,793.519**	-96.624	**2,601.851**	**-191.67**	**2,543.377**	**-58.47**	**2,484.132**	**-59.245**	**2,325.851**	-158.281
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
Generator Total		**30,757.167**	**28,798.176**	**-1,958.991**	**28,948.778**	**150.602**	**29,171.692**	222.914	**29,271.643**	**99.95**	**29,547.9**	**276.26**	**29,658.943**	**111.043**	**29,725.612**	66.669
Import Total		**1,924.000**	**1,768.111**	**-155.889**	**1,768.111**	**0.000**	**1,641.821**	-126.290	**1,616.821**	**-25.00**	**1,399.037**	**-217.78**	**1,337.037**	**-62**	**1,337.037**	0
***Grand Total**		**36,326.011**	**34,038.003**	**-2,288.008**	**33,607.032**	**-430.971**	**33,607.032**	0.000	**33,490.315**	**-116.72**	**33,490.32**	**0.00**	**33,480.112**	**-10.208**	**33,388.5**	-91.612
Net ICR (NICR)		**33,456**	**33,456**	**0**	**33,456**	**0**	**33,456**	**0**	**33,114**	**-342**	**33,114**	**0.00**	**33,391**	**277**	**33,391**	**0**

* 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	671.28	-109.926	575.63	-95.65		
	Passive Demand	1,631.335	1,519.740	-111.595	1,519.311	-0.43	1,543.793	24.482	1,544.276	0.48	1,544.119	-0.157	1,607.705	63.586		
Demand Total		**2,748.033**	**2,563.459**	**-184.574**	**2,463.581**	**-99.88**	**2,476.514**	**12.933**	**2,325.482**	**-151.03**	**2,215.399**	**-110.083**	2,183.335	-32.064		
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	28,791.131	483.792	28,948.677	157.546		
	Intermittent	936.913	893.710	-43.203	903.244	9.53	913.083	9.839	838.626	-74.46	824.833	-13.793	800.286	-24.547		
Generator Total		**31,641.491**	**29,040.547**	**-2,600.944**	**29,030.288**	**-10.26**	**29,436.085**	**405.797**	**29,145.965**	**-290.12**	**29,615.964**	**469.999**	29,748.963	132.999		
Import Total		**1,830.000**	**1,606.862**	**-223.138**	**1,606.862**	**0.00**	**1,616.401**	**9.539**	**1,576.401**	**-40.00**	**1,576.401**	**0**	1,440.401	-136		
***Grand Total**		**36,219.524**	**33,210.868**	**-3,008.656**	**33,100.731**	**-110.14**	**33,529.000**	**428.269**	**33,047.848**	**-481.15**	**33,407.764**	**359.916**	33,372.699	-35.065		
Net ICR (NICR)		**32,968**	**32,968**	**0**	33,529	561	33,529	0	33,529	0.00	33,529	0	33,152	-377		

* 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								
Demand Total		**3,040.596**	**2,846.367**	**-194.23**	**2,852.865**	6.498								
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								
Generator Total		**29,424.738**	**29,422.751**	**-1.99**	**29,589.043**	**166.292**								
Import Total		**1,237.034**	**1,237.034**	**0.00**	**1,375.53**	**138.496**								
***Grand Total**		**33,702.368**	**33,506.152**	**-196.22**	**33,817.438**	**311.286**								
Net ICR (NICR)		**33,855**	**34,061**	**206.00**	**34,061**	0								

* 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												
Demand Total		**2,803.411**												
Generator	*Non-Intermittent*	29,550.564												
	Intermittent	891.616												
Generator Total		**30,442.18**												
Import Total		**1,449**												
***Grand Total**		**34,694.591**												
Net ICR (NICR)		**34,189**												

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

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

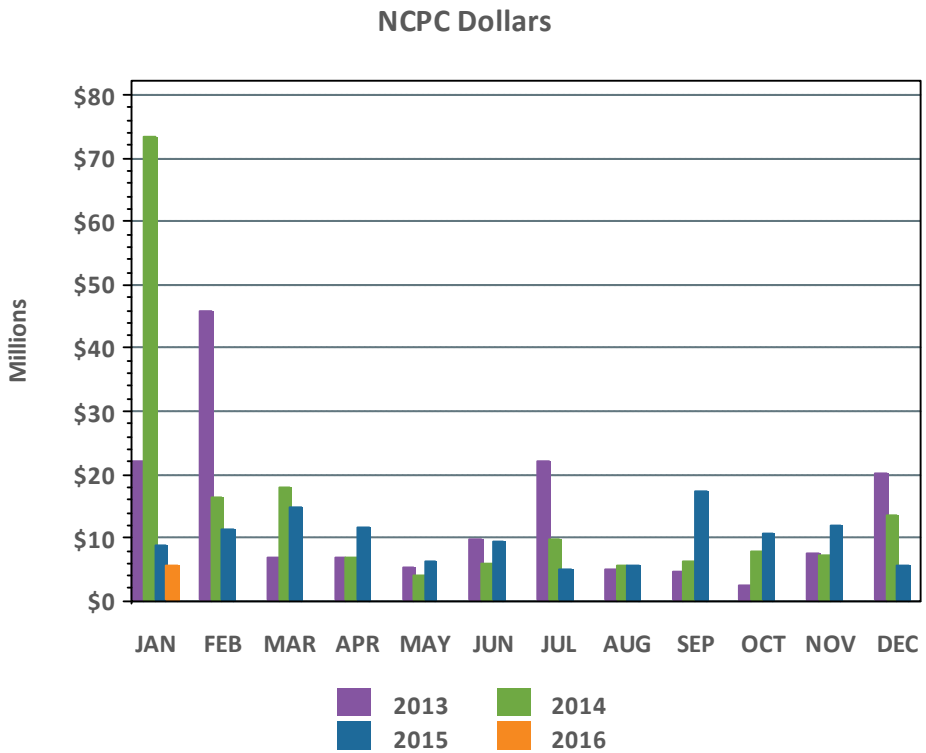
Definitions

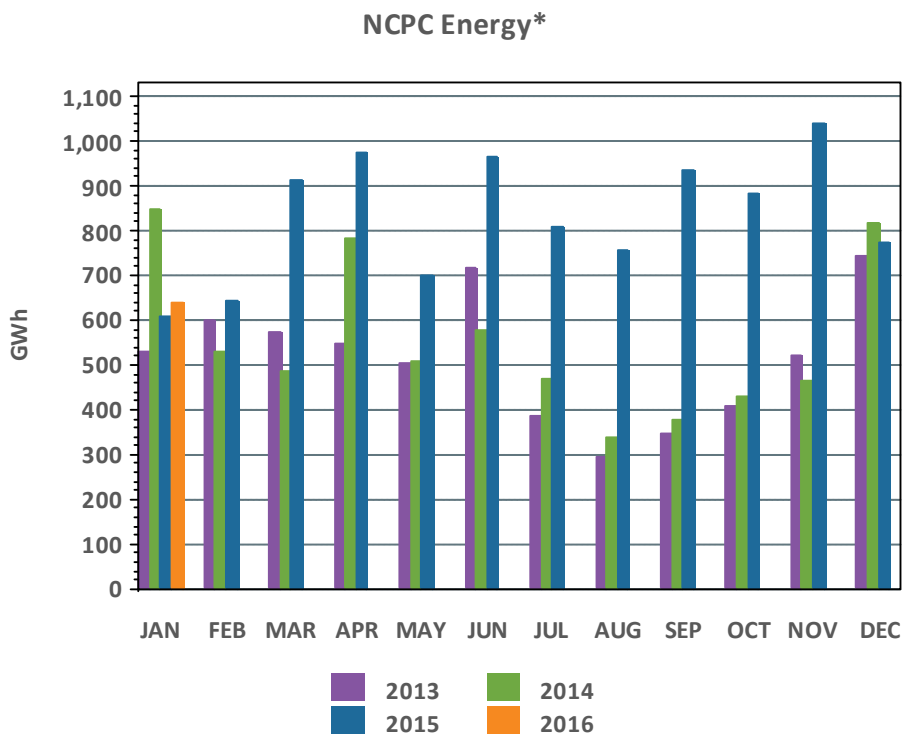
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2nd 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 1st Contingency	Market	DA 1st C (excluding at external nodes) is allocated to system DALO. RT 1st 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 1st Contingency	Market	DA 1st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2nd Contingency	Market	DA and RT 2nd 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

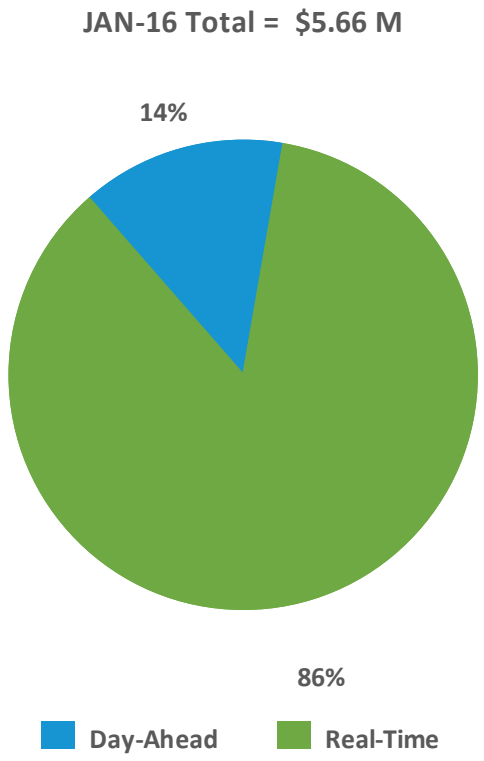
Year-Over-Year Total NCPC Dollars and Energy

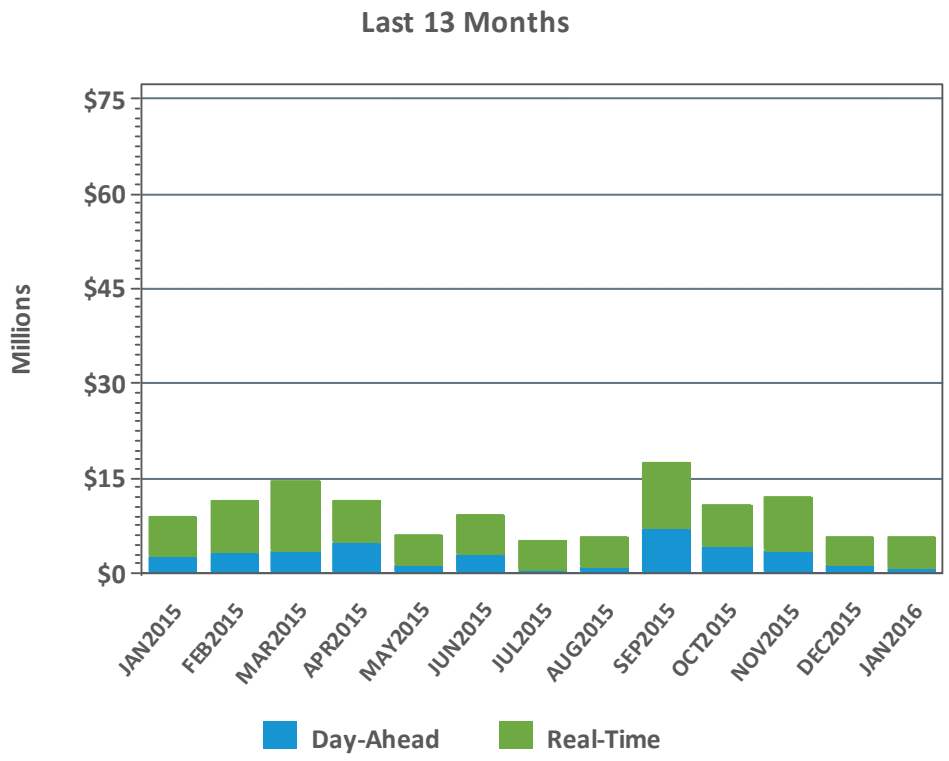




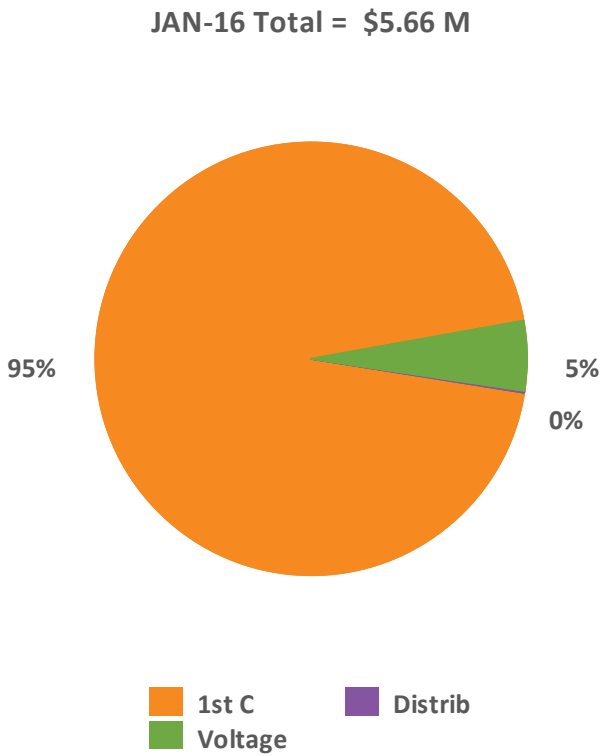
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits, assessed during hours in which they are NCPC-eligible. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.

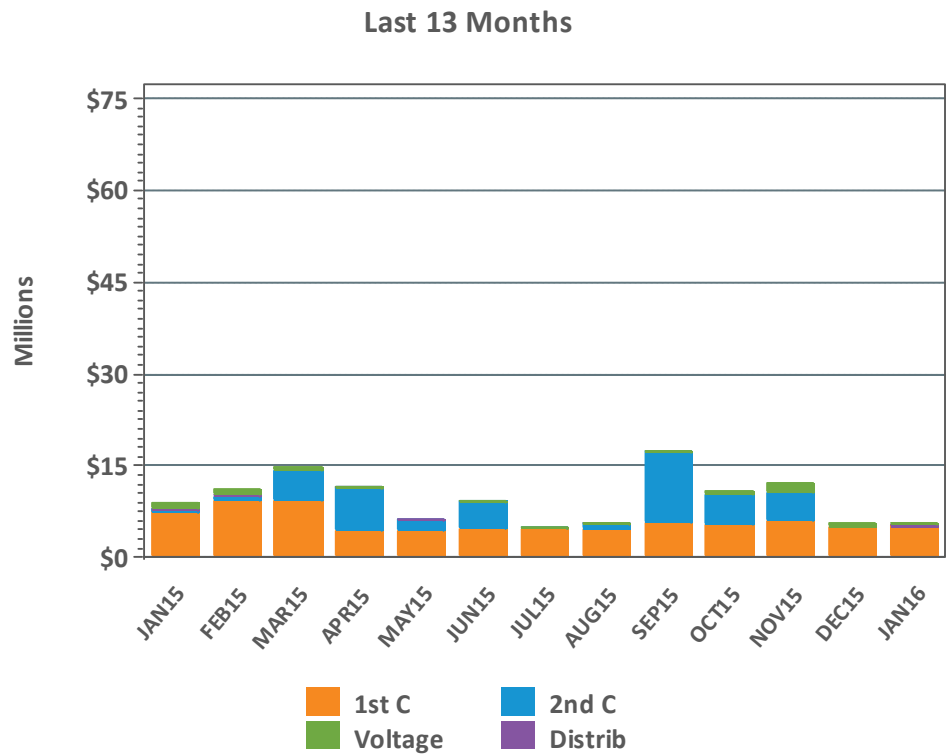
DA and RT NCPC Charges





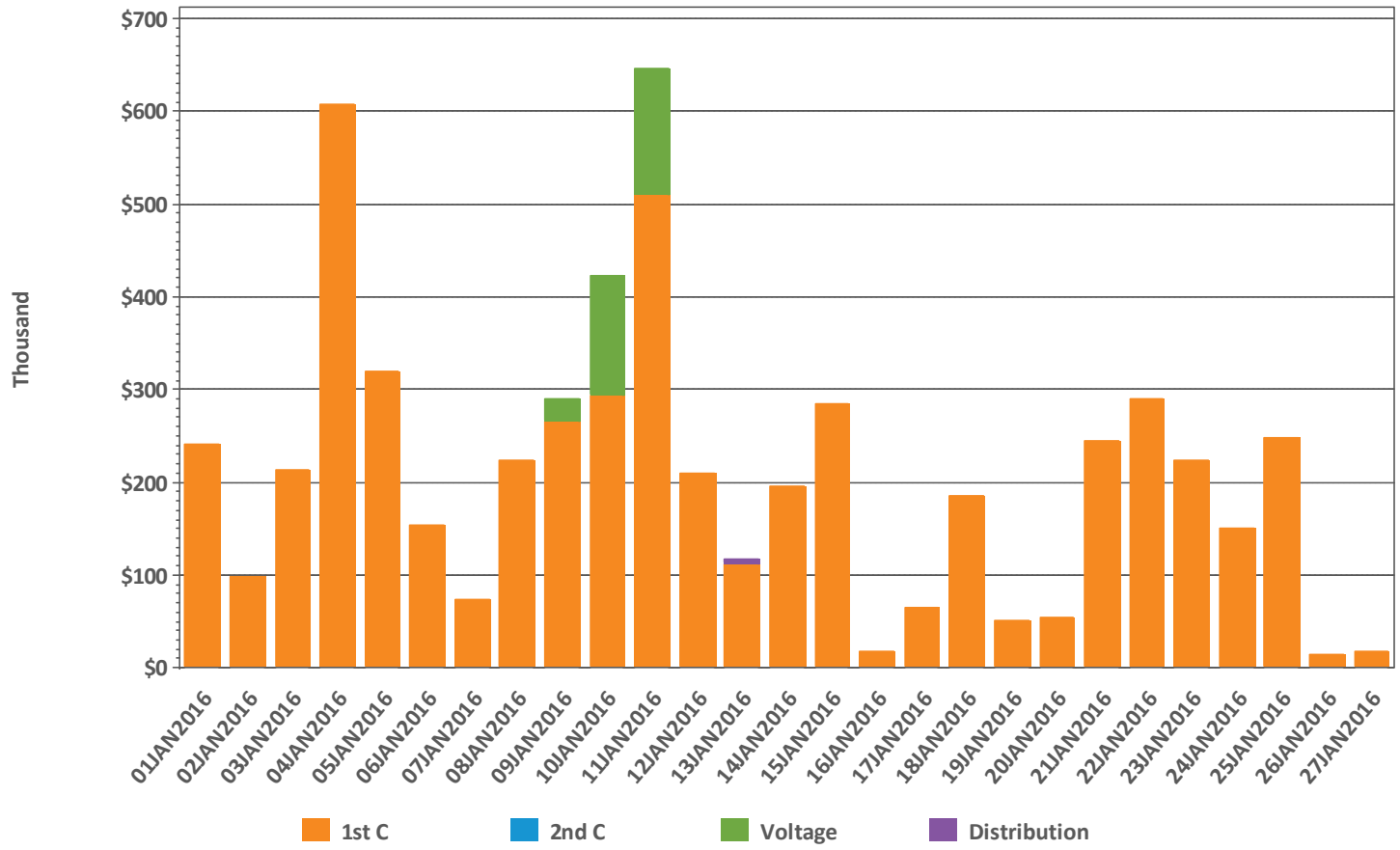
NCPC Charges by Type



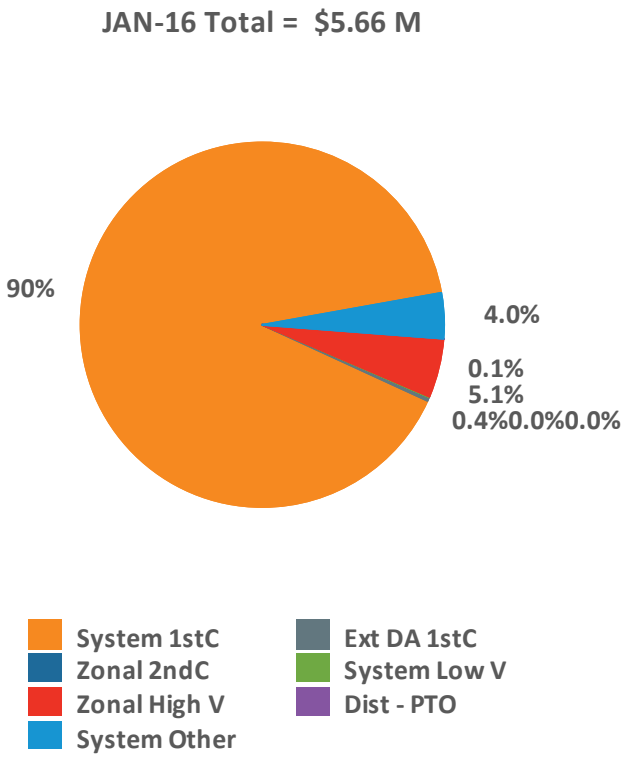


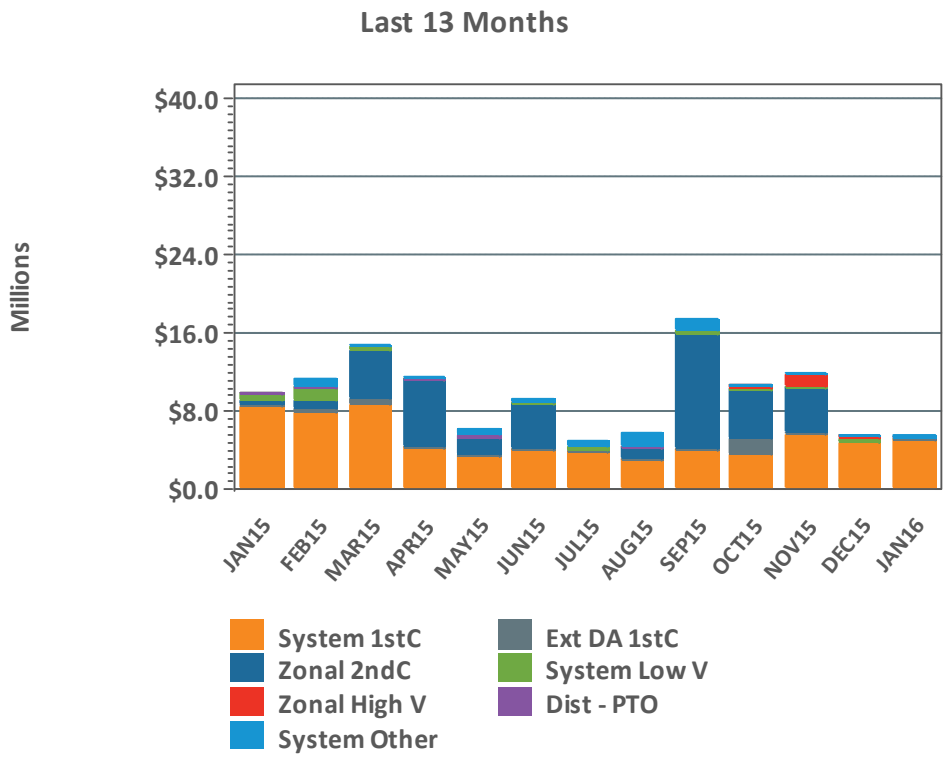
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type

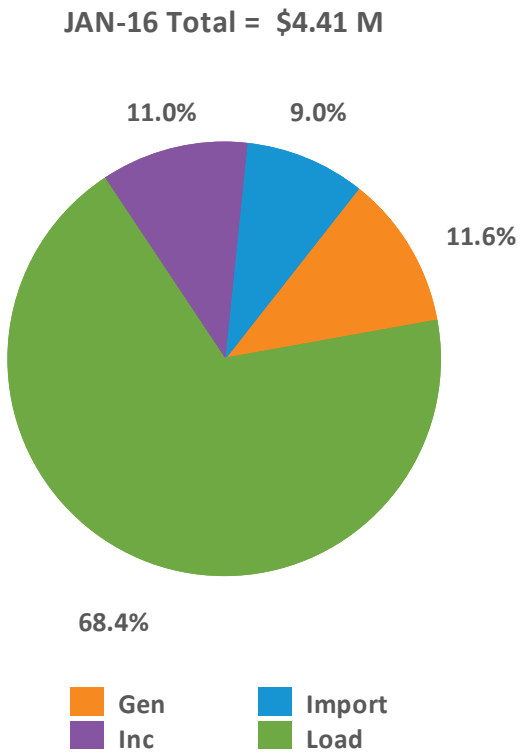


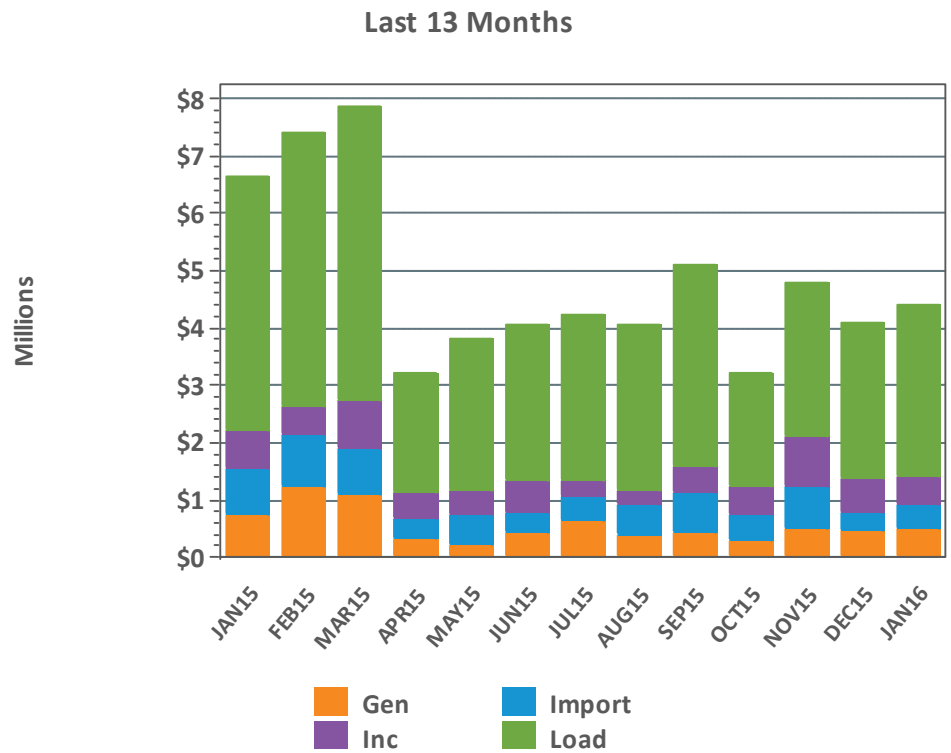
NCPC Charges by Allocation





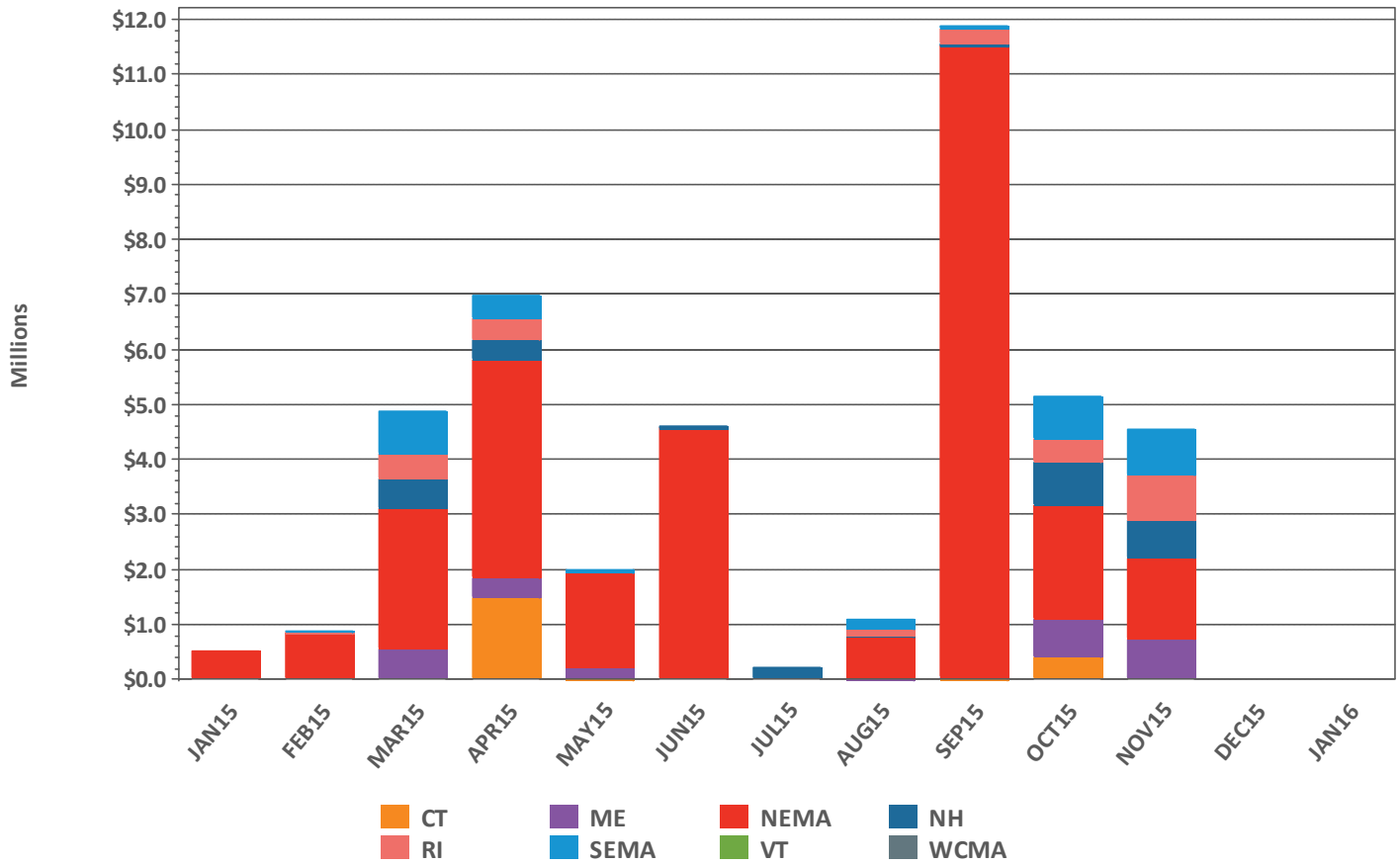
RT First Contingency Charges by Deviation Type





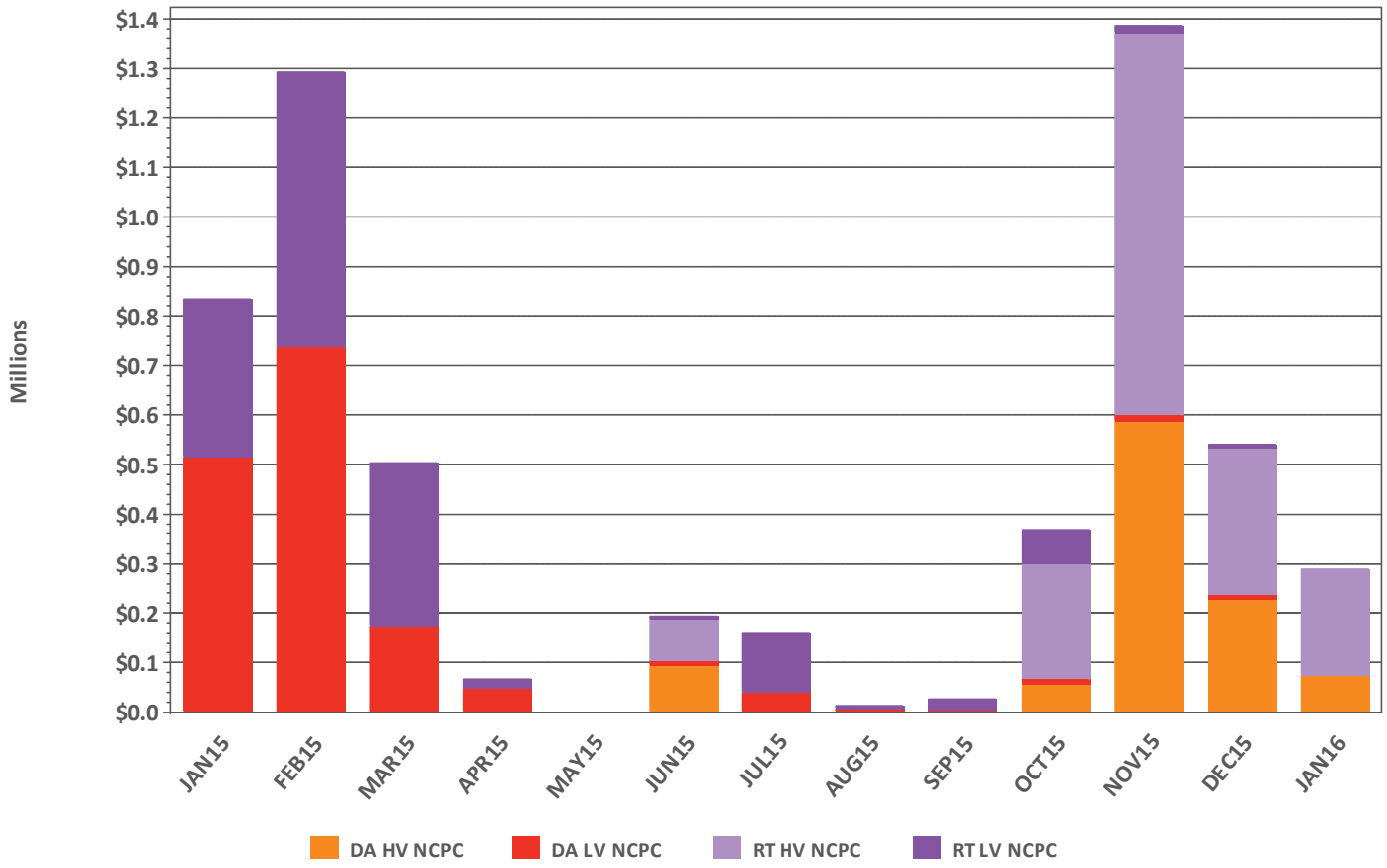
Gen – Generator deviations
Inc – Increment Offer deviations
Imp – Import deviations
Load – Load obligation deviations

LSCPR Charges by Zone

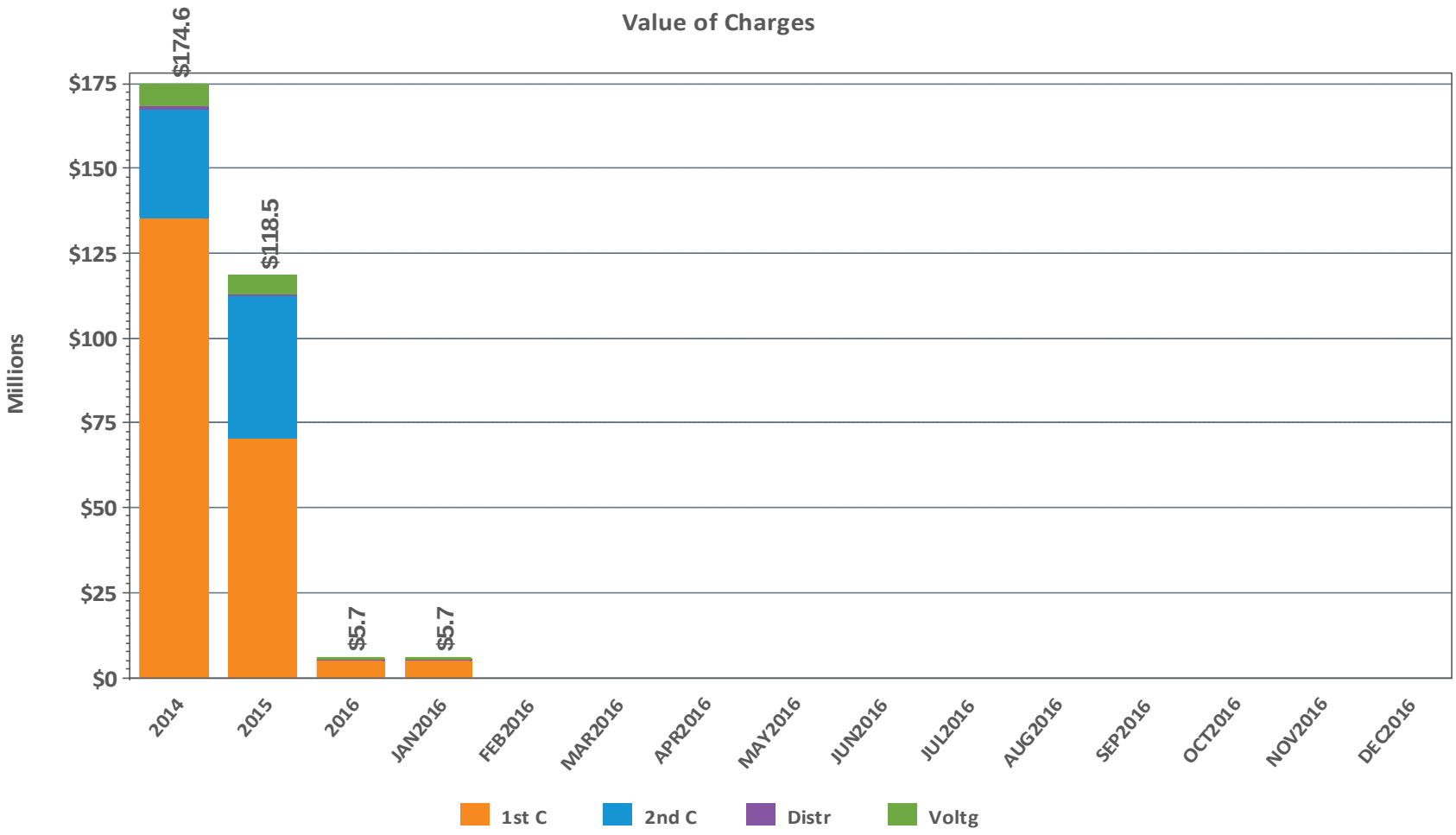


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region
EXT – External Locations

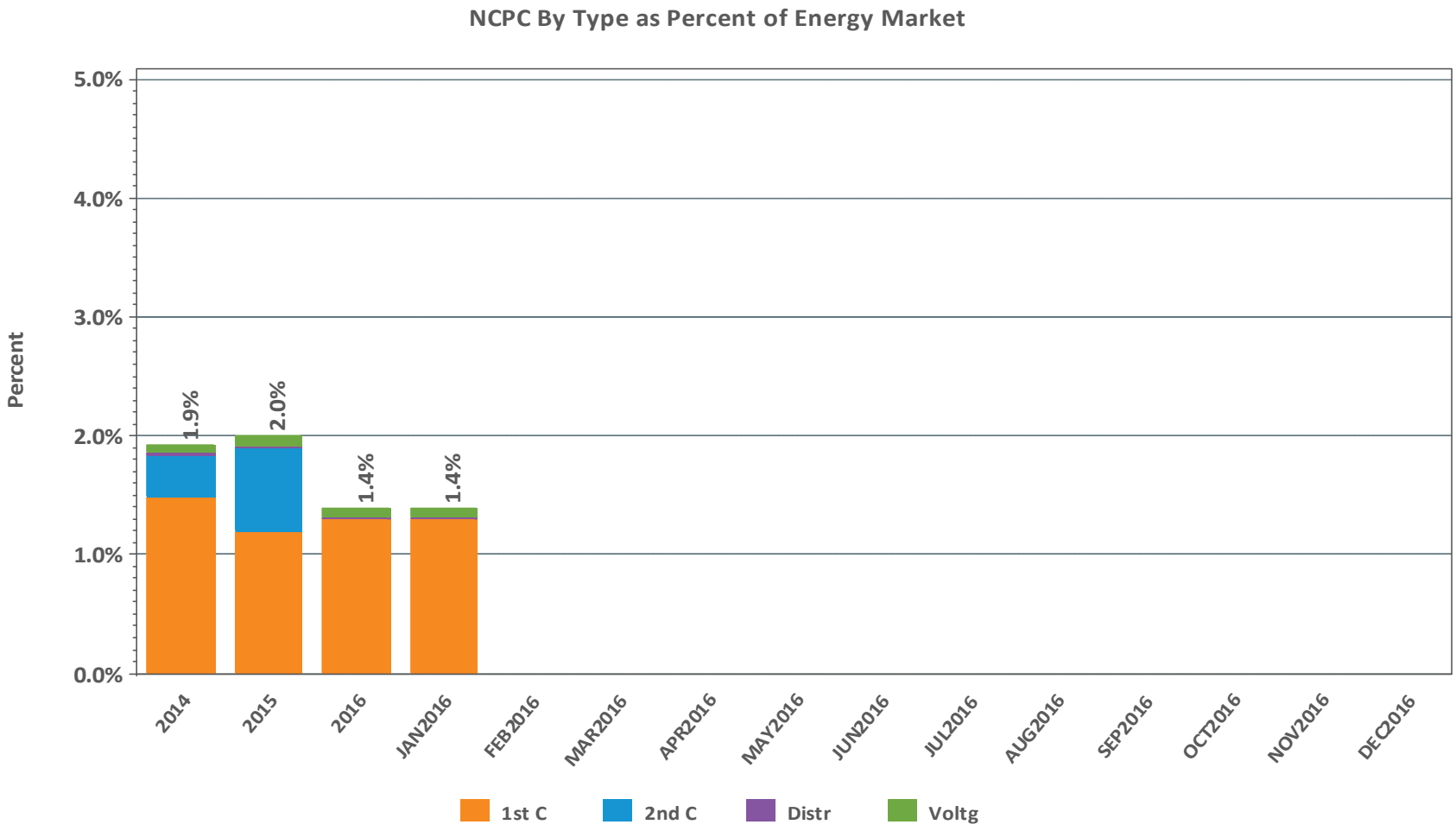
NCPC Charges for Voltage Support and High Voltage Control



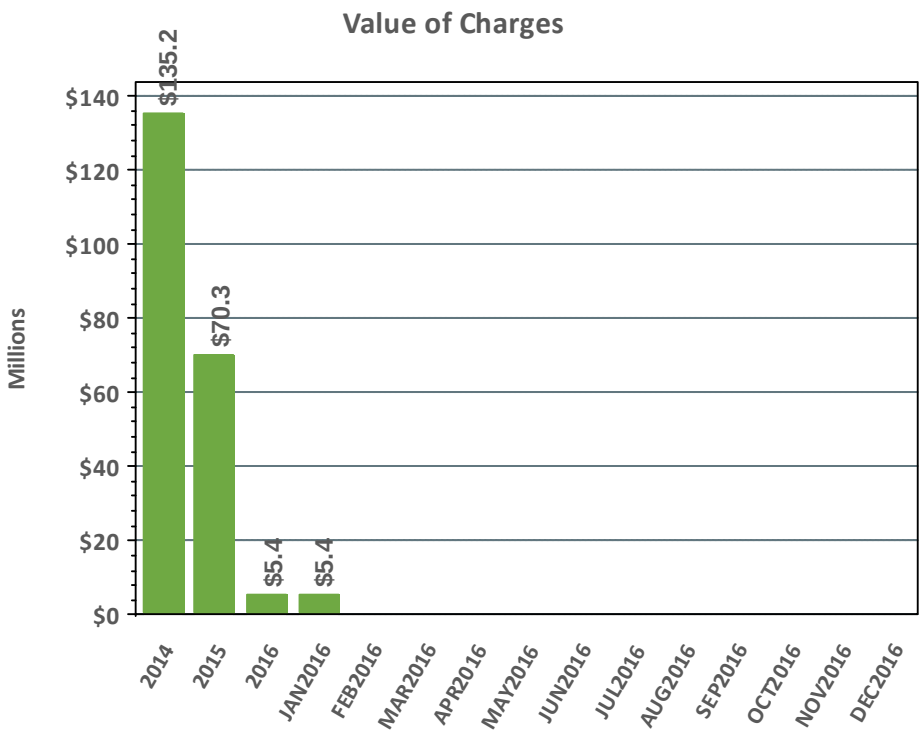
NCPC Charges by Type

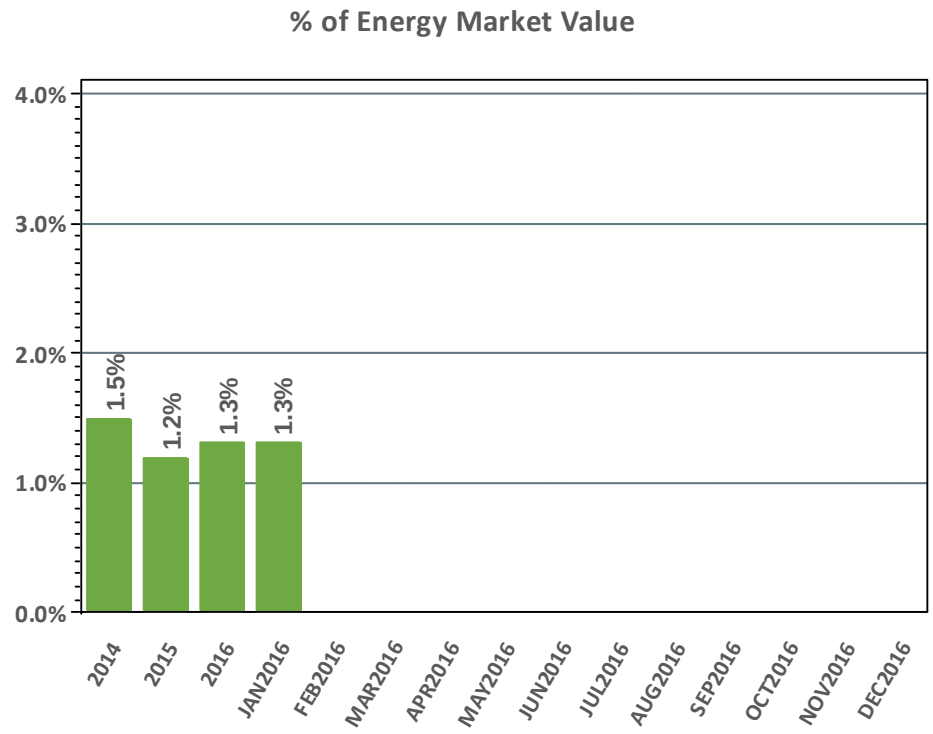


NCPC Charges as Percent of Energy Market



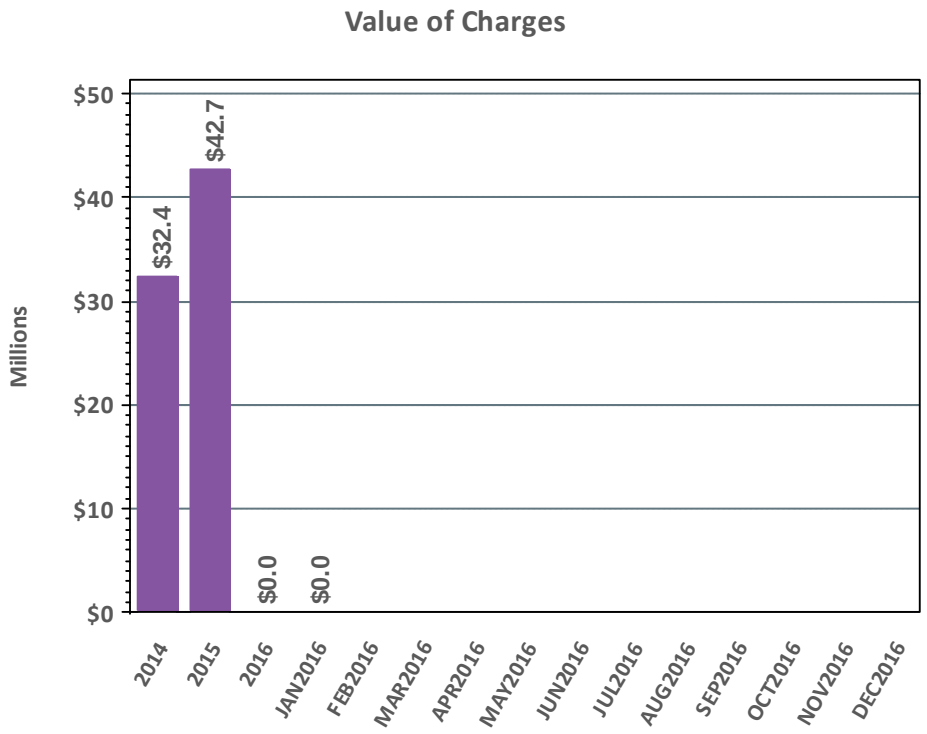
First Contingency NCPC Charges

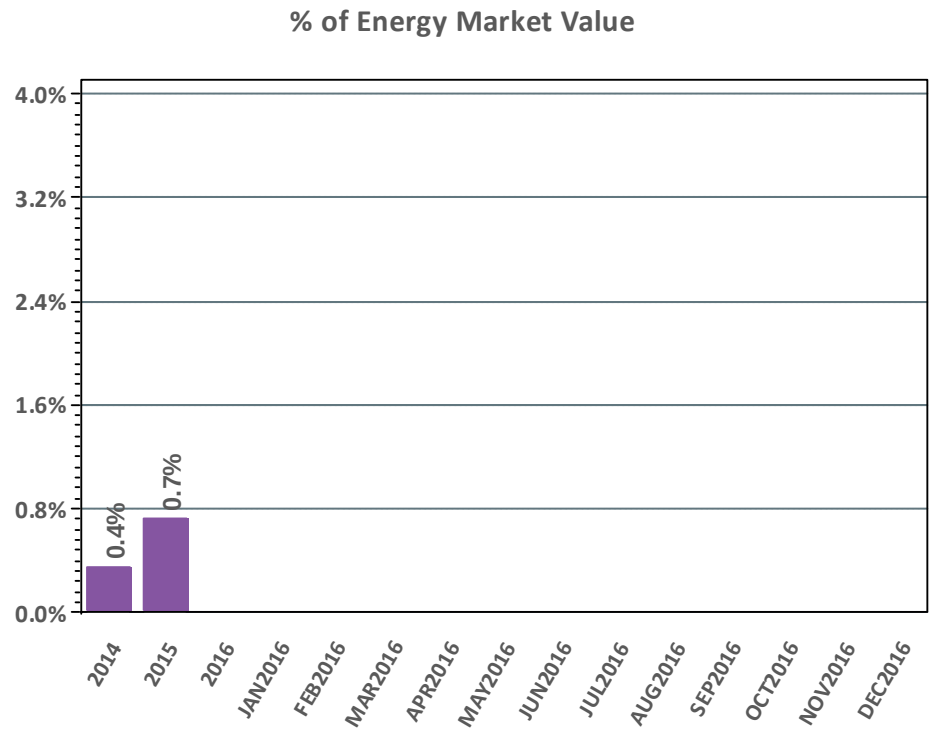




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

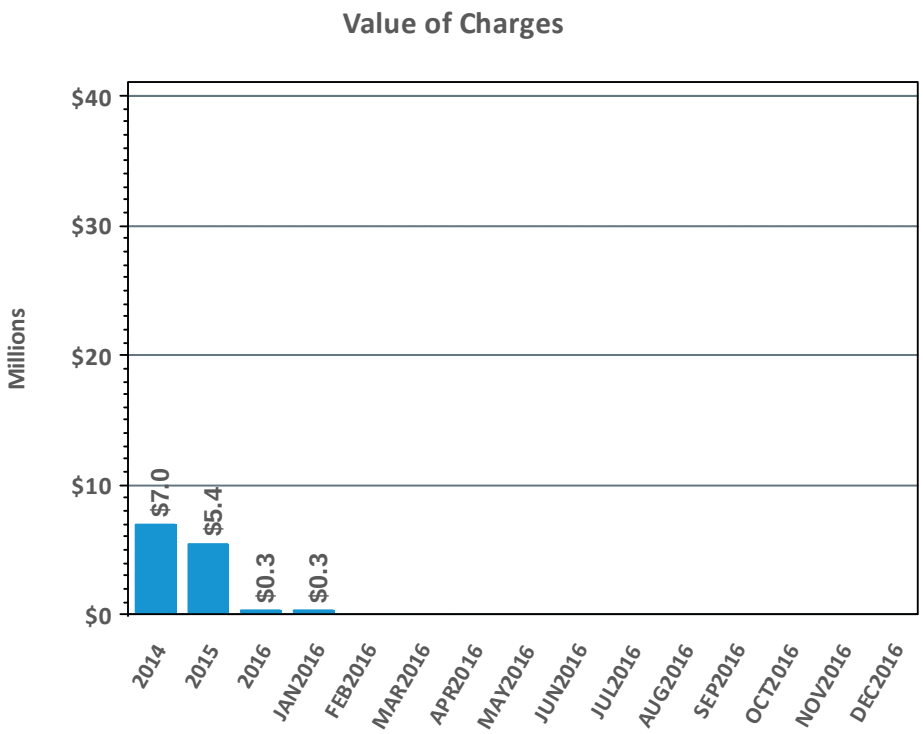
Second Contingency NCPC Charges

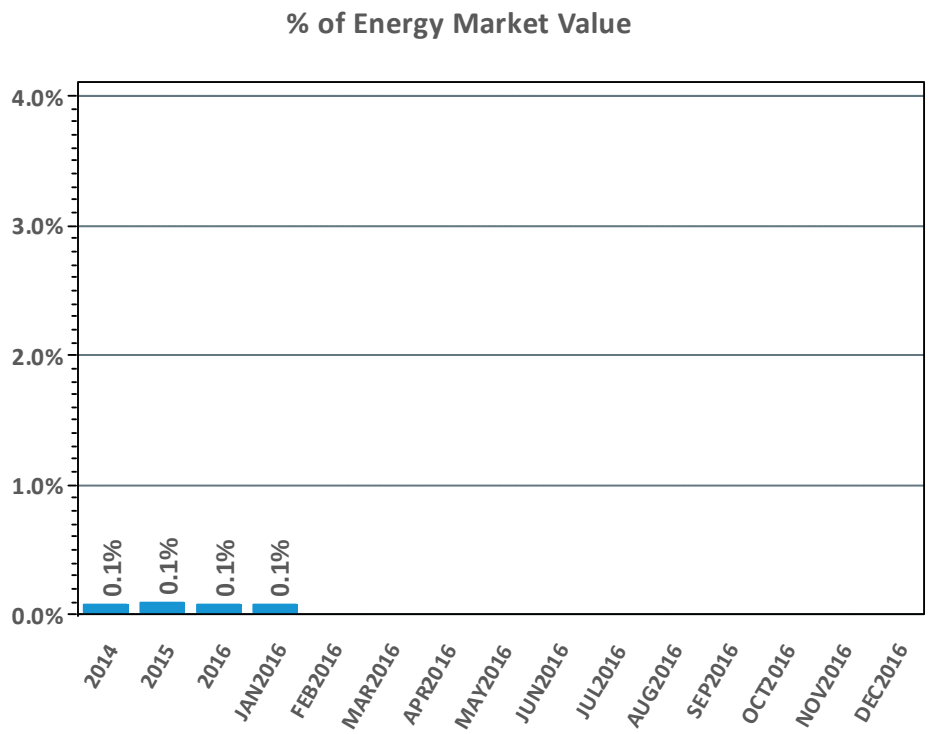




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

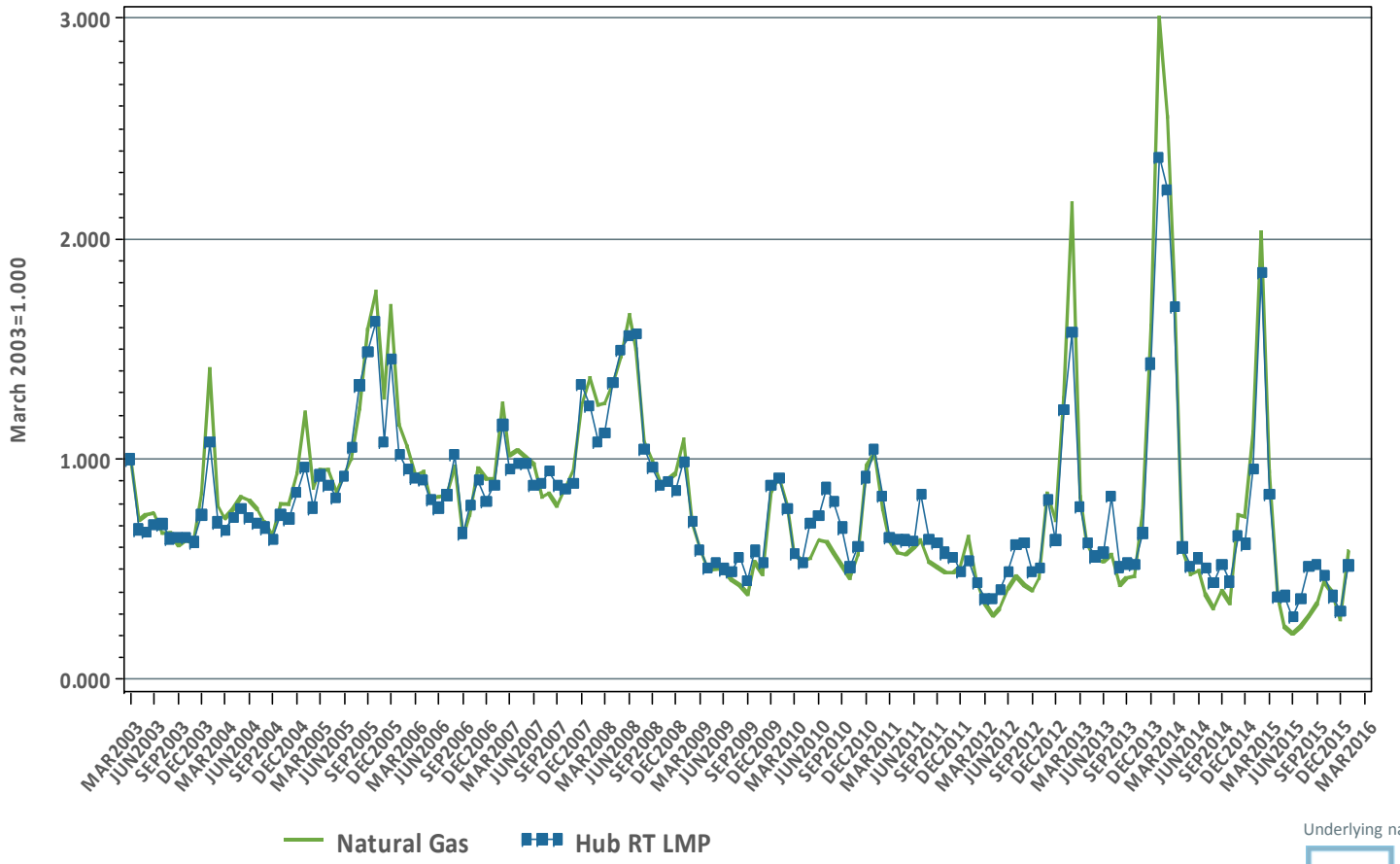
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 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%
Year 2015	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$42.56	$41.23	$40.81	$42.11	$41.58	$42.20	$42.23	$41.93	$41.90
Real-Time	$41.58	$40.58	$39.23	$40.21	$40.22	$41.03	$41.21	$40.96	$41.00
RT Delta %	-2.3%	-1.6%	-3.9%	-4.5%	-3.3%	-2.8%	-2.4%	-2.3%	-2.2%

January-15	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$71.54	$69.90	$67.81	$70.13	$70.07	$71.05	$71.48	$71.11	$71.14
Real-Time	$66.16	$64.57	$62.85	$64.30	$64.27	$65.67	$66.07	$65.42	$65.59
RT Delta %	-7.5%	-7.6%	-7.3%	-8.3%	-8.3%	-7.6%	-7.6%	-8.0%	-7.8%
January-16	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$40.41	$40.08	$38.88	$40.10	$40.14	$40.30	$40.50	$40.44	$40.36
Real-Time	$35.88	$35.64	$33.98	$35.28	$35.22	$35.75	$35.89	$35.78	$35.73
RT Delta %	-11.2%	-11.1%	-12.6%	-12.0%	-12.3%	-11.3%	-11.4%	-11.5%	-11.5%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	-43.5%	-42.7%	-42.7%	-42.8%	-42.7%	-43.3%	-43.3%	-43.1%	-43.3%
Yr over Yr RT	-45.8%	-44.8%	-45.9%	-45.1%	-45.2%	-45.6%	-45.7%	-45.3%	-45.5%

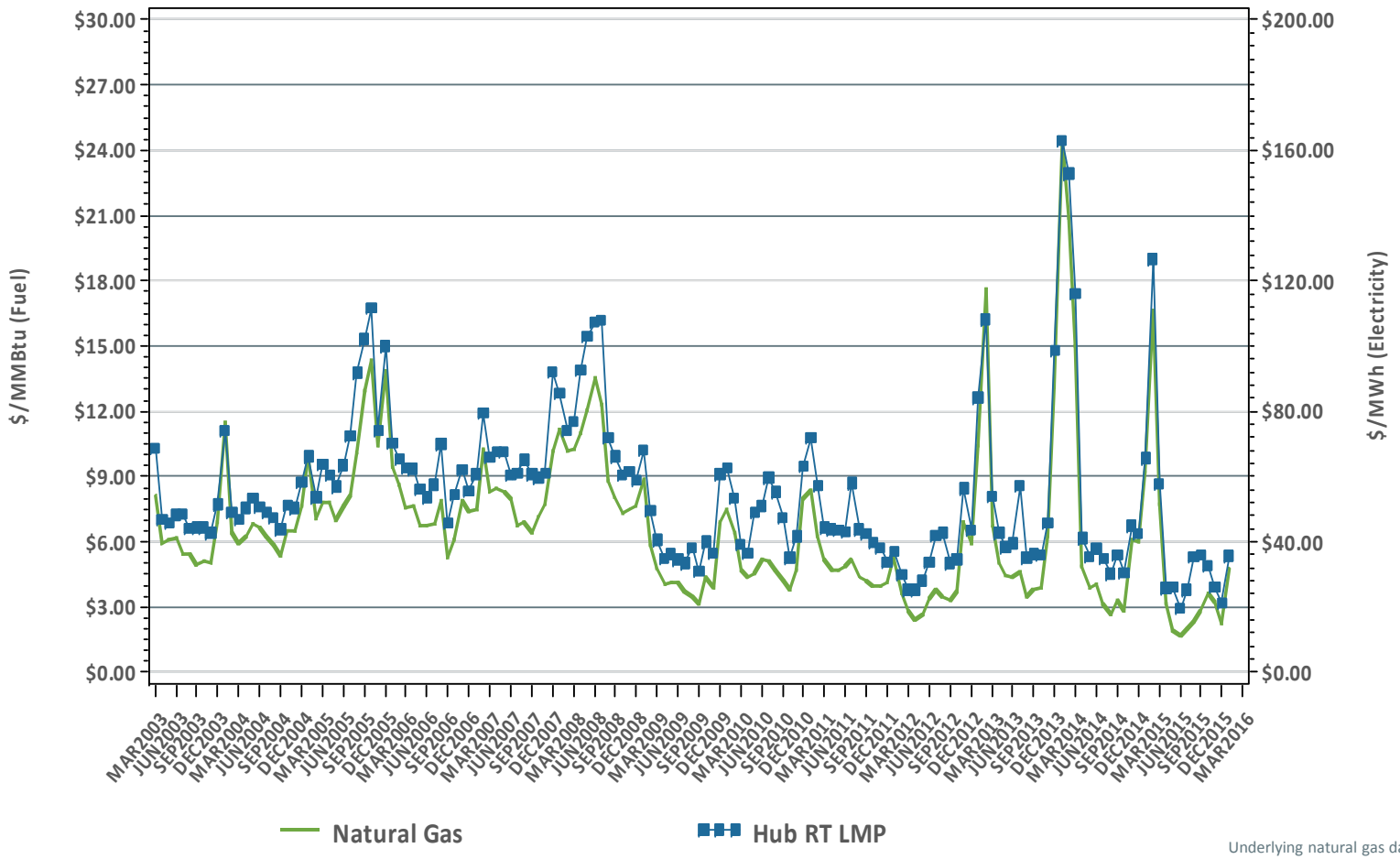
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

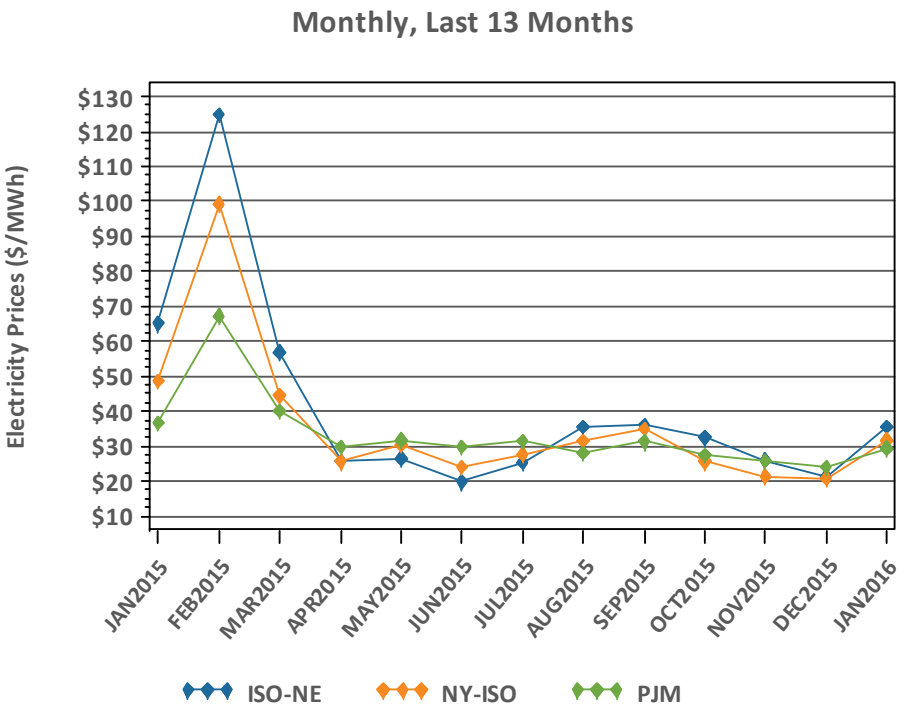
Monthly Average Fuel Price and RT Hub LMP



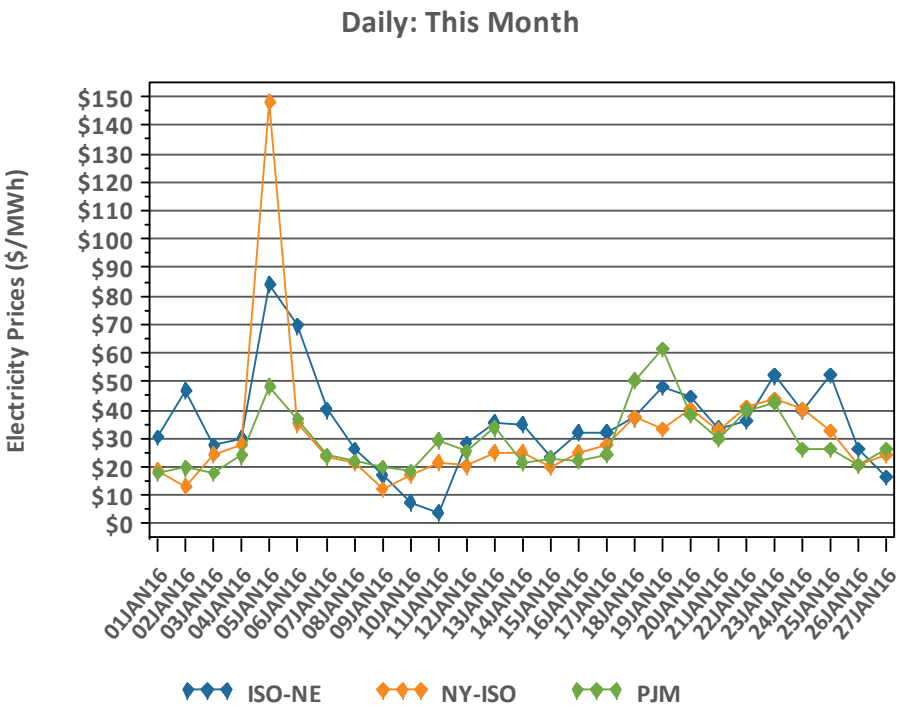
Underlying natural gas data furnished by:

ICE Global markets in clear view

New England, NY, and PJM Real Time Prices

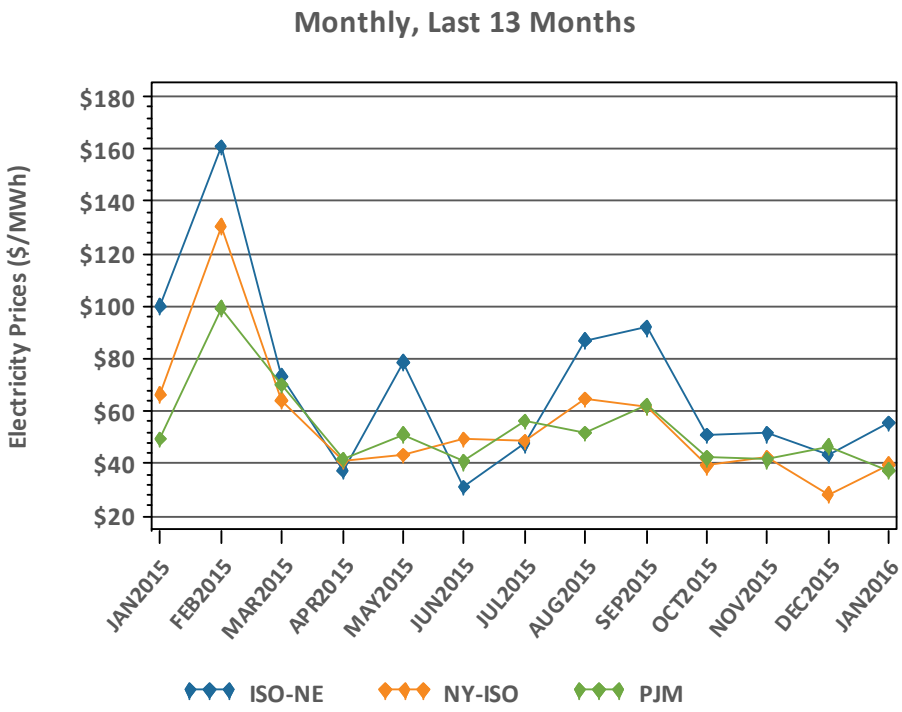


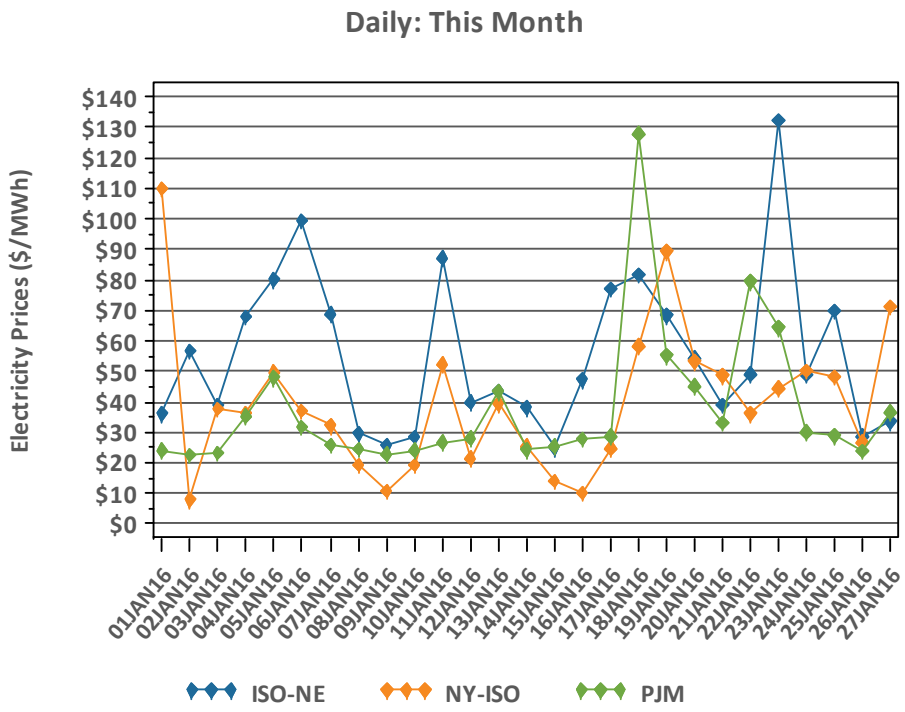
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





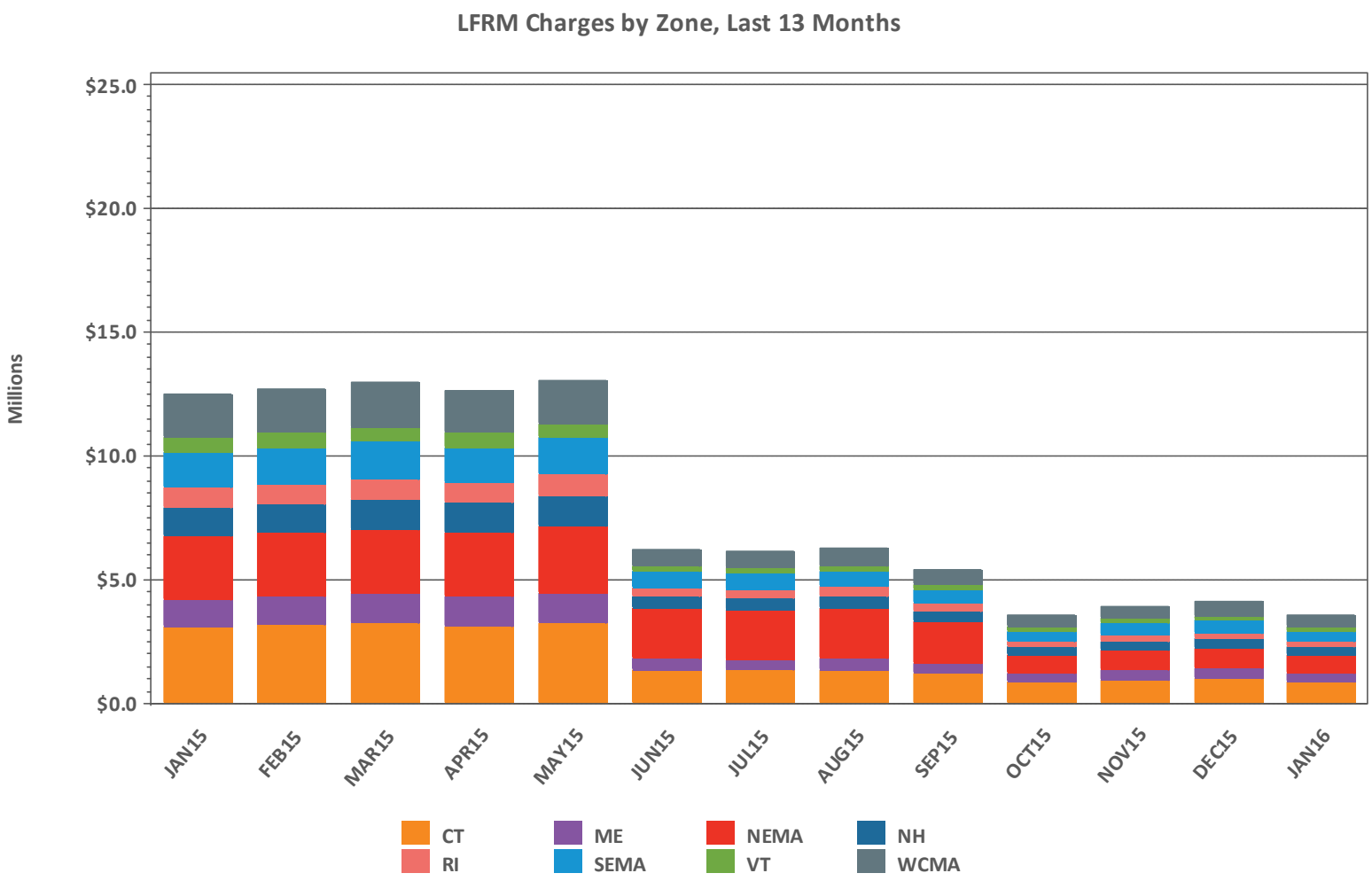
*Forecasted New England peak hour is reflected.

Reserve Market Results – January 2016

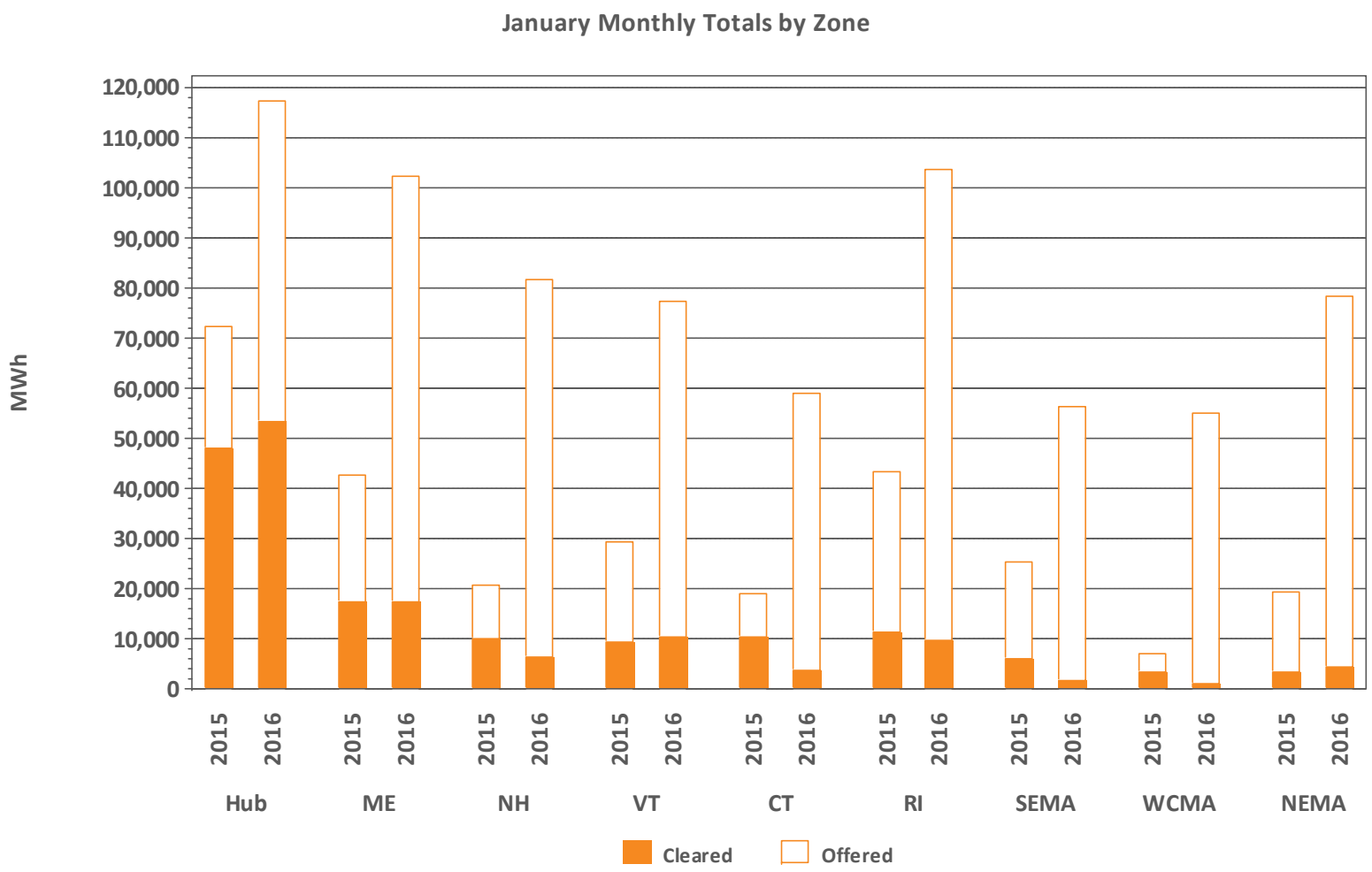
- Maximum potential Forward Reserve Market payments of $3.7M were reduced by credit reductions of $41K, failure-to-reserve penalties of $104K and failure-to-activate penalties of $2K, resulting in a net payout of $3.6M or 96% of maximum
  - Rest of System: $1.74M/$1.83M (95%)
  - Southwest Connecticut: $0.33M/$0.33M (99%)
  - Connecticut: $1.53M/$1.58M (97%)
  - Real-Time Reserve payments were zero

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

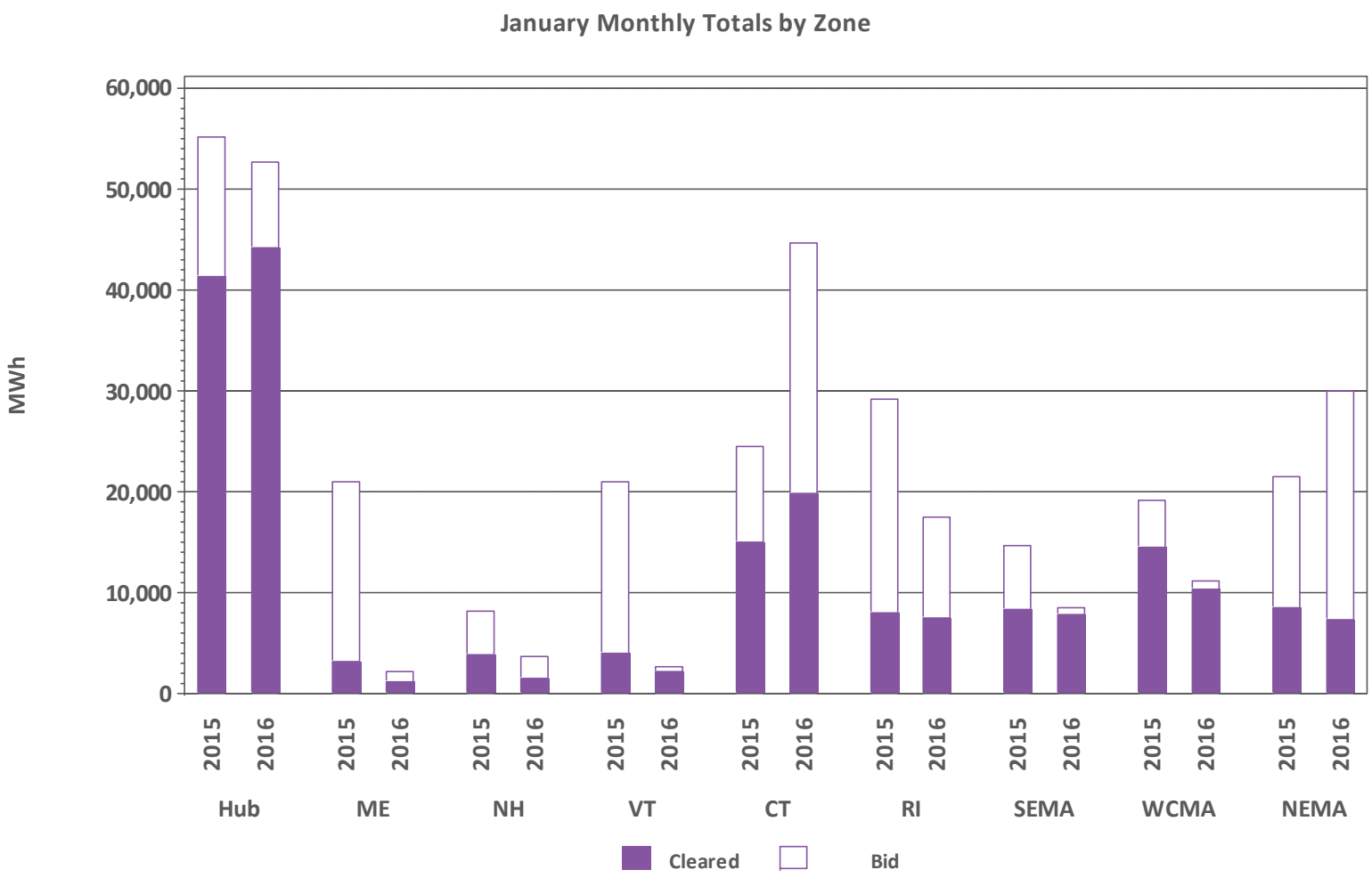
LFRM Charges to Load by Load Zone ($)



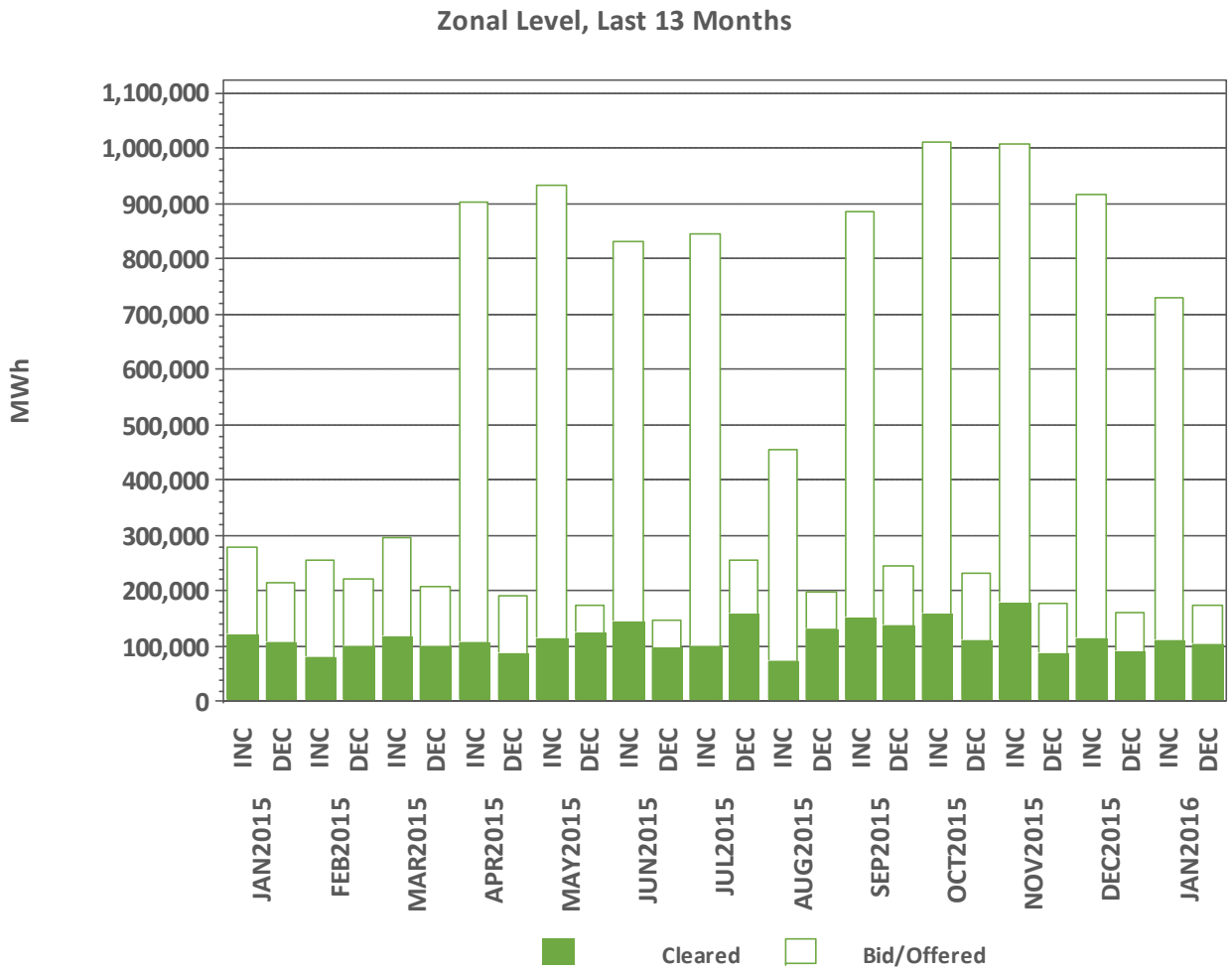
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

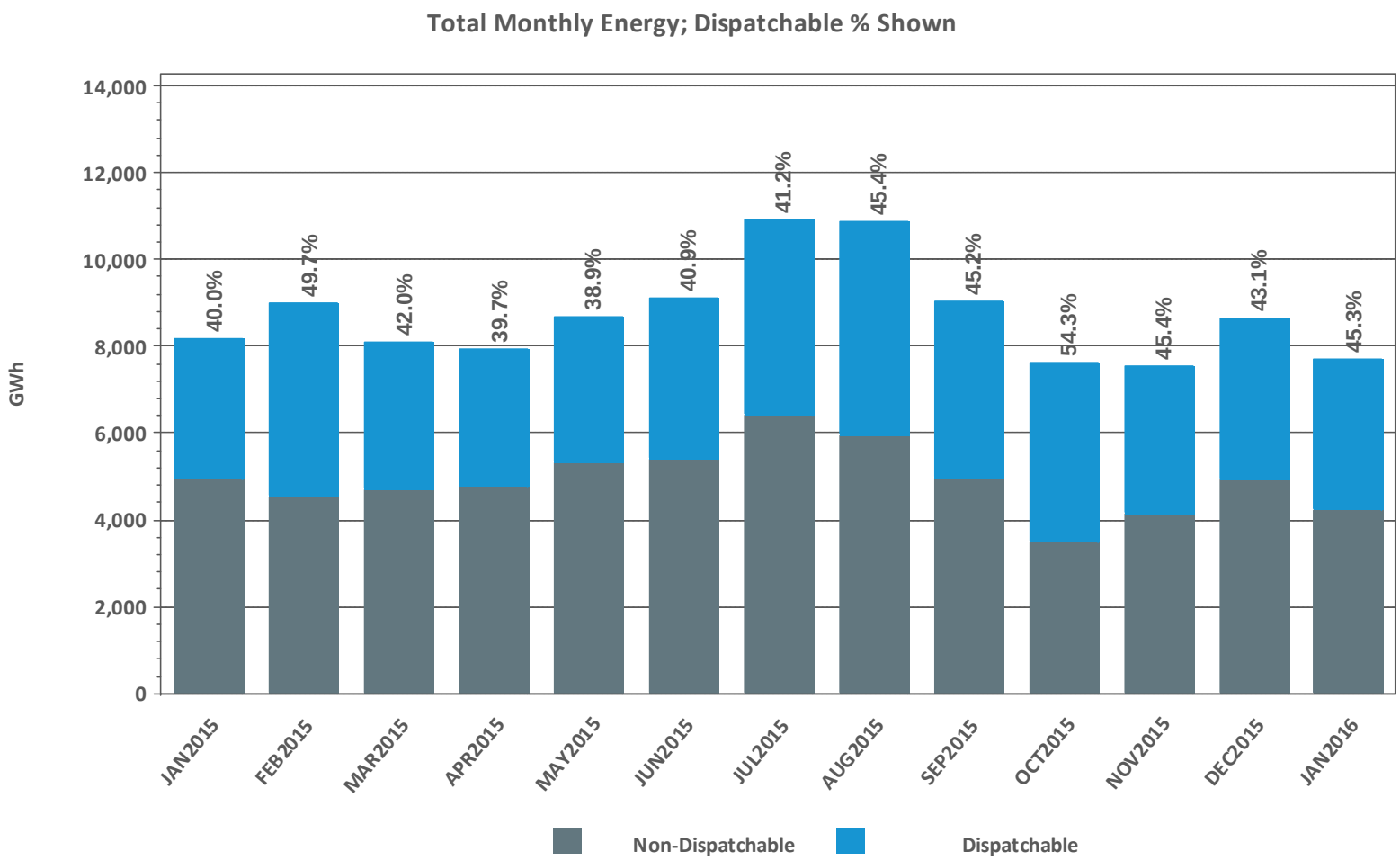


Total Increment Offers and Decrement Bids



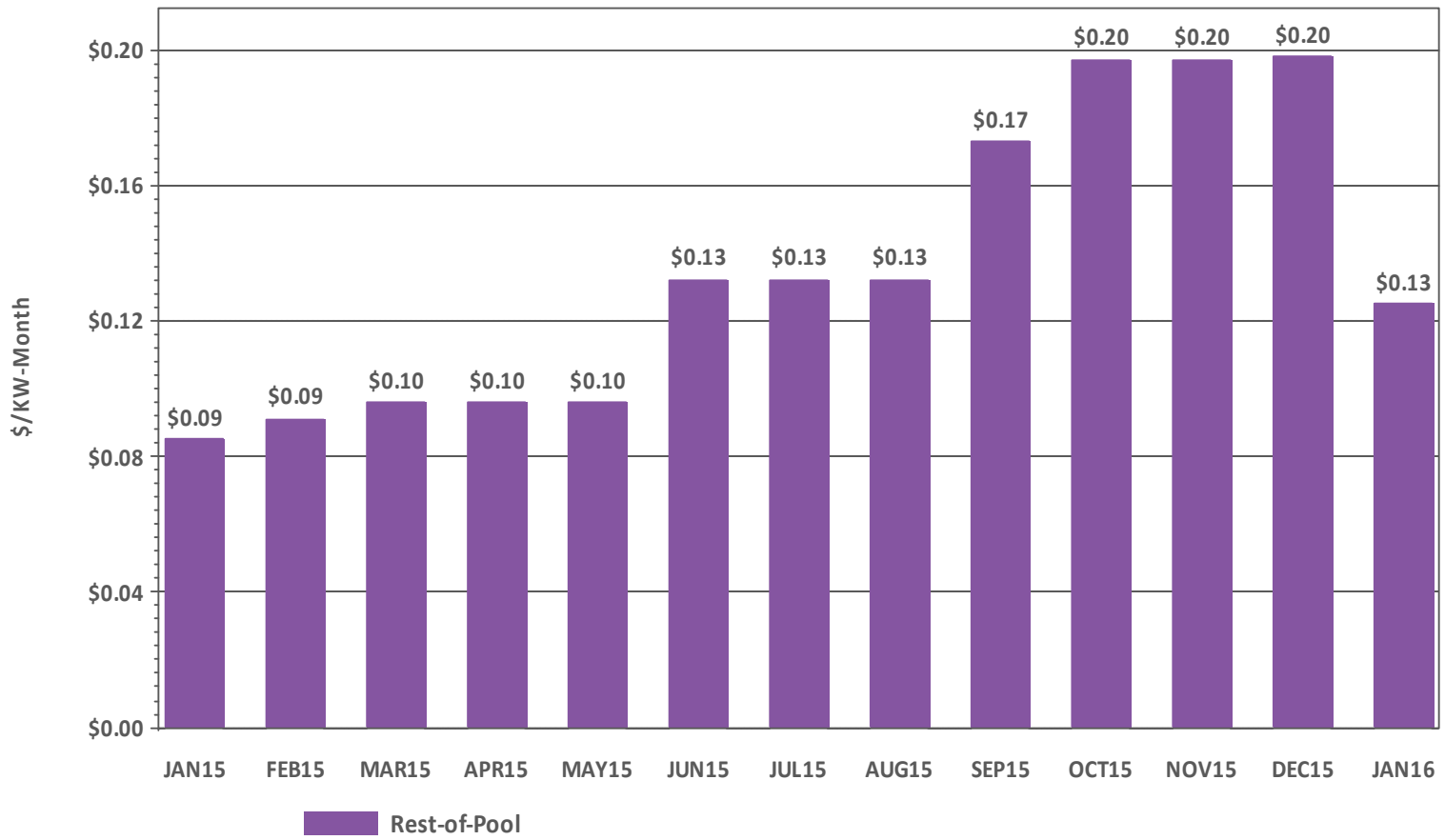
Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



* 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).

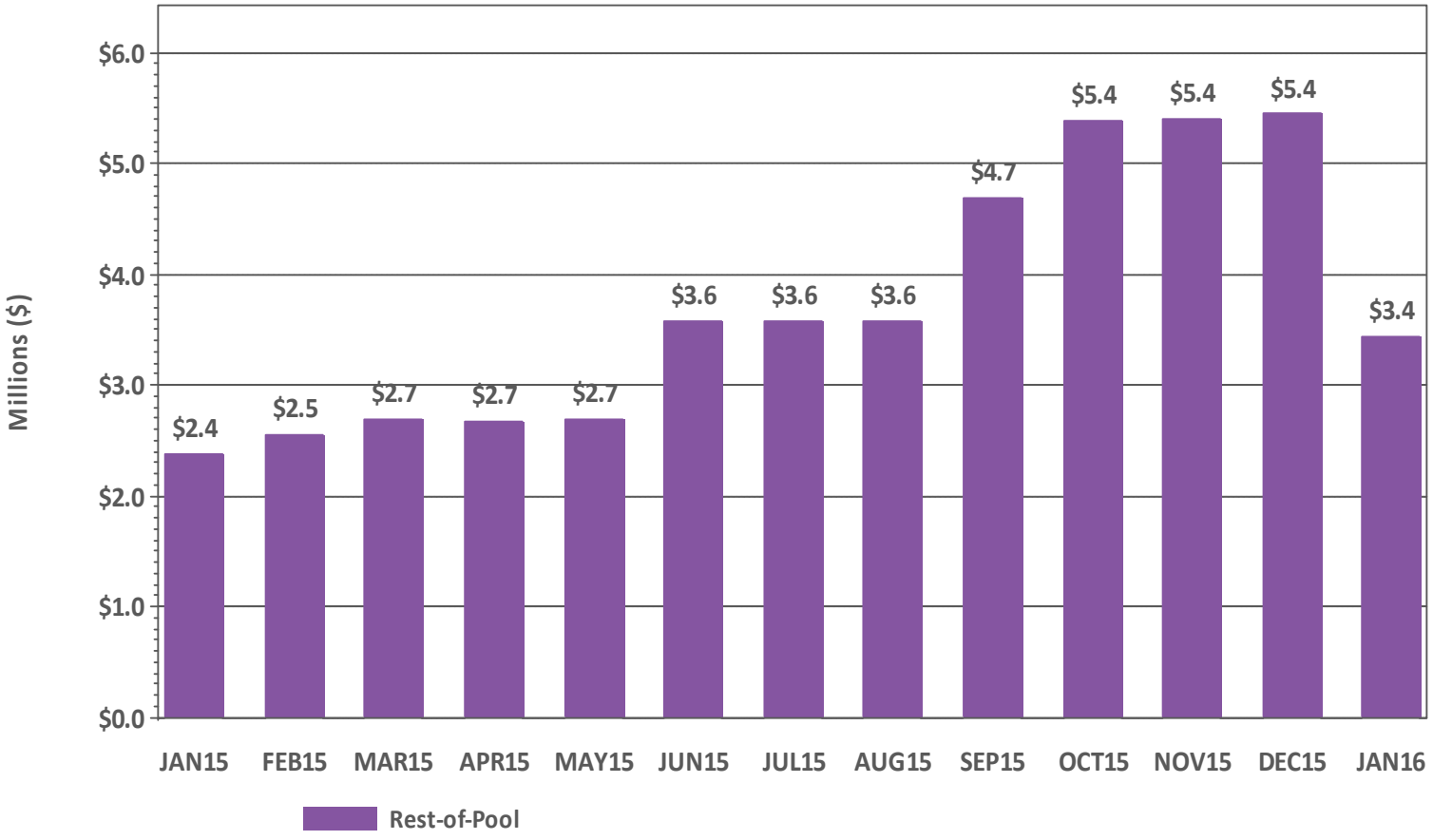
Rolling Average Peak Energy Rent (PER)



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)

RSP16 and the RSP Process

- The ISO filed changes to the OATT consistent with the NPC vote
  - Issue RSP no less than once every three years
  - Change the timing of the RSP page turn, public meeting, and issuance from specific months to more generic requirements would better coordinate with stakeholder schedules, ISO workloads, and the processes of neighboring systems
- It is the ISO's intent to issue the next RSP in 2017, pending further input from stakeholders, and to issue RSP every other year
  - Consistent with past practices, PAC discussions of presentations and reports are ongoing

Planning Advisory Committee (PAC)

- February 17 PAC Meeting Agenda (tentative)
  - Keene Road Transfer Limit Update
  - Environmental Update
  - Continue Discussion on Planning Assumptions – Probabilistic Based Transmission Assessment and Tools
  - Representative ICR and Zonal Values
  - Maine 2023 Needs Assessment

Distributed Generation Forecast Working Group (DGFWG)

- The next DGFWG meeting is scheduled for February 24 to discuss the draft forecast

Environmental Matters

- Final 2014 New England Electric Generator Air Emissions Report was posted on January 6
- Mercury & Air Toxics Standards upheld
- 2015 Ozone Standard and impacts on southern New England
- EPA final Clean Power Plan and possible regional compliance strategies
  - Clean Power Plan survives initial stay request
  - Regional Greenhouse Gas Initiative adjusting 2016 program review to accommodate Clean Power Plan submittal needs

Economic Studies

- The ISO is performing three economic studies for 2015
  - Keene Road area wind development and analysis of local interface constraints (request by SunEdison)
  - Offshore Wind Deployment (request by Massachusetts Clean Energy Center)
  - Maine Upgrades Identified in ISO-NE's Strategic Transmission Analysis for Wind Integration (request by RENEW Northeast)
- The ISO discussed the draft Keene Road study results with the PAC on December 15
- Discussion of draft economic study results are planned for the March 28 PAC meeting
- Requests for 2016 economic studies by stakeholders must be submitted for public posting by April 1

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

Connecticut River Valley

Status as of 2/1/16

Project Benefit: Addresses system needs in the Connecticut River Corridor in Vermont

Upgrade	Expected In-Service	Present Stage
Rebuild 115 kV line K31, Coolidge-Ascutney	May-18	1
Ascutney Substation - Add a +50/-25 MVAR dynamic reactive device	Aug-18	1
Hartford Substation - Split 25 MVAR capacitor bank into two 12.5 MVAR banks	April-17	1
Chelsea Station - Rebuild to a three-breaker ring bus	Oct-17	1

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

New Hampshire/Vermont 10-Year Upgrades

Status as of 2/1/16

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	3
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	Nov-15	4*
New 115 kV overhead/submarine line, Madbury-Portsmouth	Dec-17	2
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	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 2/1/16

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected In-Service	Present Stage
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Jun-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 2/1/16

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 2/1/16

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	3
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	2
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-16**	4
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	2
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Dec-17	2
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	2

*Replaces the NEEWS Central Connecticut Reliability Project
**Placed in-service ahead of schedule

Greater Hartford and Central Connecticut (GHCC) Projects, cont.*

Status as of 2/1/16

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)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a new 115 kV underground cable from Newington to Southwest Hartford and associated terminal equipment including a 2% series reactor	Dec-18	2
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Dec-16	2
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	Dec-17	2
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Dec-18	2
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Dec-18	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut (GHCC) Projects, cont.*

Status as of 2/1/16

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
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	2
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	2
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Dec-18	2
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	2
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Dec-17	2
Add a 345 kV breaker in series with breaker 5T at Southington	Dec-17	2

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 2/1/16

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 new control house at Southington 115 kV substation	Dec-17	2
Add a new 115 kV line from Frost Bridge to Campville	Jun-18	2
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	2
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-17	2
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-16**	4
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-16**	4
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Dec-16	2

* Replaces the NEEWS Central Connecticut Reliability Project

** Placed in-service ahead of schedule

Southwest Connecticut (SWCT) Projects

Status as of 2/1/16

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-16	2
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	2
Rebuild Bunker Hill to a 9-breaker substation in breaker-and-a-half configuration	Dec-18	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-18	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-15	4

Southwest Connecticut Projects, cont.

Status as of 2/1/16

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-18	1
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-18	1
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Dec-18	1
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	Dec-18	1
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	Dec-18	1
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Dec-18	1
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	Dec-18	1

Southwest Connecticut Projects, cont.

Status as of 2/1/16

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
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-16	2
Terminal equipment upgrade at the Newtown substation (1876)	Dec-15	4*
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Dec-16	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

* Placed in-service ahead of schedule

Southwest Connecticut Projects, cont.

Status as of 2/1/16

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 2 x 20 MVAR capacitor banks at the Hawthorne substation	Mar-16	3
Upgrade the 115 kV bus at the Baird substation	Mar-18	2
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-15	4
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Dec-18	2
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Dec-19	1

Southwest Connecticut Projects, cont.

Status as of 2/1/16

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
Remove the Sackett phase shifter	Feb-17	2
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Jan-17	2
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Jan-17	2
Separate the 3827 (Beseck to East Devon) and 1610 (Southington to June to Mix Avenue) double circuit towers	Dec-18	1
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Dec-16	2
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Dec-16	3
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

Greater Boston Projects

Status as of 2/1/16

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

Upgrade	Expected In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Mar-18	2
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Dec-17	2
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Oct-17	2
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	Oct-17	2
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Dec-16	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	4
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-16	2

Greater Boston Projects, cont.

Status as of 2/1/16

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	May-17	3
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	2
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	2
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-16	3
Install a new 115 kV line from Sudbury to Hudson	Dec-18	1

Greater Boston Projects, cont.

Status as of 2/1/16

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	2
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Jun-16	3
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	2
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	Dec-16	2
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-16	2
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 2/1/16

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

Upgrade	Expected In-Service	Present Stage
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 2/1/16

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	2
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	2
Install a 200 MVAR STATCOM at Coopers Mills	Dec-18	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	2
Install a 115 kV breaker in series with the 29 breaker at K Street	Dec-16	2

Pittsfield/Greenfield Projects

Status as of 2/1/16

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected In-Service	Present Stage
Separate and reconductor the Cabot Taps (A-127 and Y-177 115 kV lines)	Sep-16	2
Install a 115 kV tie breaker at the Harriman Station, with associated buswork, reconductor of buswork and new control house	Apr-17	2
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	Dec-16	3
Build a new 115 kV three-breaker switching station (Erving) ring bus	Dec-16	3
Build a new 115 kV line from Northfield Mountain to the new Erving Switching Station	Dec-16	3
Install 115 kV 14.4 MVAR capacitor banks at Cumberland, Podick and Amherst Substations	Dec-15	4

Pittsfield/Greenfield Projects, cont.

Status as of 2/1/16

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected In-Service	Present Stage
Rebuild the Cumberland to Montague 1361 115 kV line and terminal work at Cumberland and Montague. At Montague Substation, reconnect Y177 115 kV line into 3T/4T position and perform other associated substation work	Dec-16	3
Remove the sag limitation on the 1512 115 kV line from Blandford Substation to Granville Junction and remove the limitation on the 1421 115 kV line from Pleasant to Blandford Substation	Dec-14	4
Loop the A127W line between Cabot Tap and French King into the new Erving Substation	Oct-16	2
Reconductor A127 between Erving and Cabot Tap and replace switches at Wendell Depot	Apr-15	4

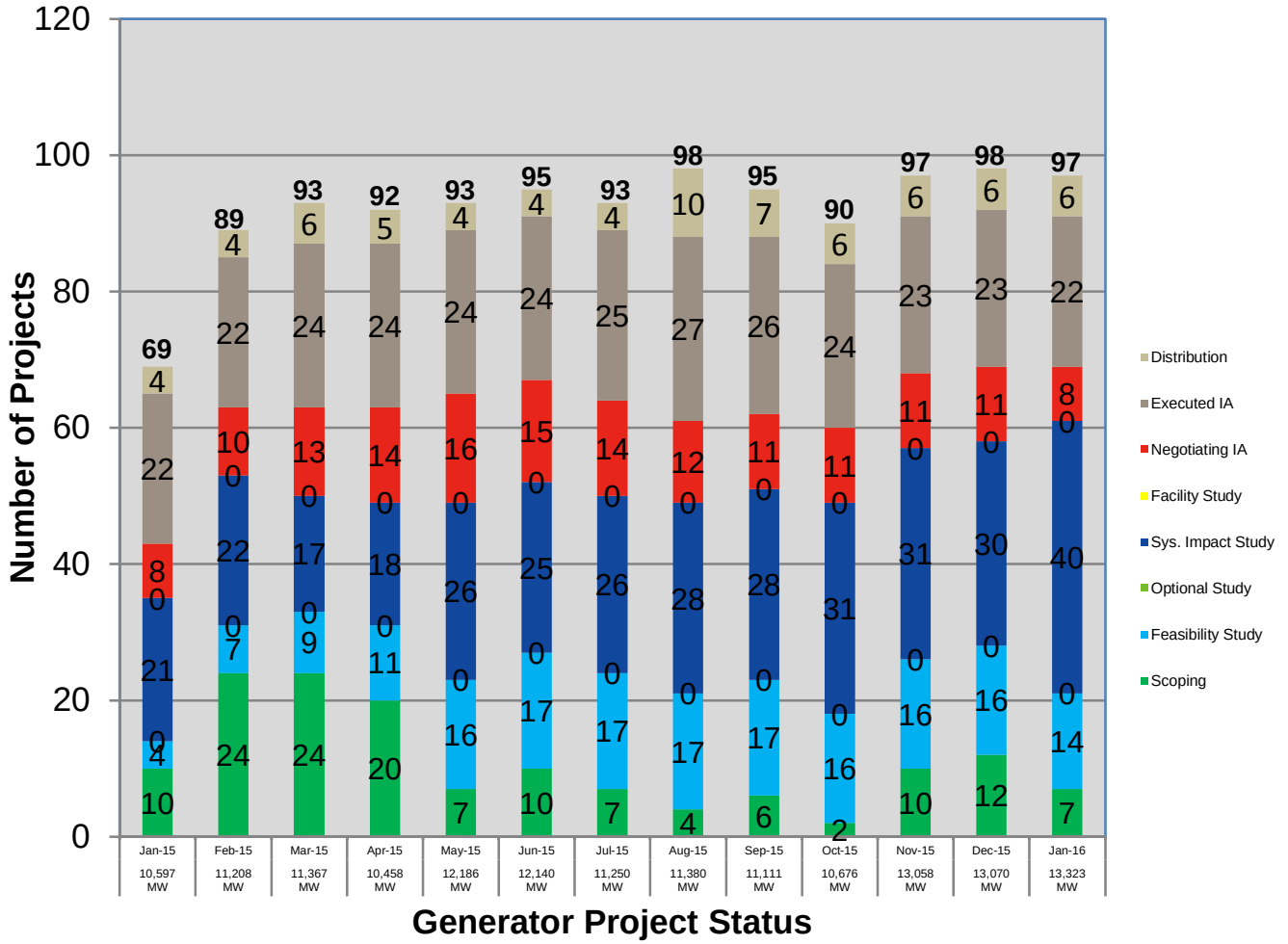
Pittsfield/Greenfield Projects, cont.

Status as of 2/1/16

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected In-Service	Present Stage
Install a 115 kV 20.6 MVAR capacitor at the Doreen substation and operate the 115 kV 13T breaker N.O.	Dec-17	1
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	1
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	1

Status of Tariff Studies



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

Note: As of January 2016, there are 8 ETU's in SIS, 1 in FS and 5 in scoping

OPERABLE CAPACITY ANALYSIS

Winter 2016

Winter 2016 Operable Capacity Analysis

50/50 Load Forecast (Reference)	February - 2016[2] CSO	February - 2016[2] SCC
Generator Operable Capacity MW [1]	30,429	32,814
OP CAP From OP-4 RTDR (+)	278	278
OP CAP From OP-4 RTEG (+)	142	142
Operable Capacity Generator with OP-4 DR and RTEG	30,849	33,234
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	867	867
Non Commercial Capacity (+)	15	15
Non Gas-fired Planned Outage MW (-)	719	738
Gas Generator Outages MW (-)	161	309
Allowance for Unplanned Outages (-) [5]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [4]	3,407	3,803
Net Capacity (NET OPCAP SUPPLY MW) [3]	24,344	26,166
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,577	20,577
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,882	22,882
Operable Capacity Margin [3]	1,462	3,284

[1] Generator Operable Capacity is based on data as of **January 19, 2016** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. SCC value is based on data as of **January 19, 2016**

[2] Load based on 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **February 6, 2016**.

[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Winter 2016 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	February- 2016[2] CSO	February - 2016[2] SCC
Generator Operable Capacity MW [1]	30,429	32,814
OP CAP From OP-4 RTDR (+)	278	278
OP CAP From OP-4 RTEG (+)	142	142
Operable Capacity Generator with OP-4 DR and RTEG	30,849	33,234
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	867	867
Non Commercial Capacity (+)	15	15
Non Gas-fired Planned Outage MW (-)	719	738
Gas Generator Outages MW (-)	161	309
Allowance for Unplanned Outages (-) [5]	3,100	3,100
Generation at Risk Due to Gas Supply (-) [4]	3,761	4,049
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,990	25,920
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,222	21,222
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,527	23,527
Operable Capacity Margin [3]	463	2,393

[1] Generator Operable Capacity is based on data as of **January 19, 2016** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. SCC value is based on data as of **January 19, 2016**

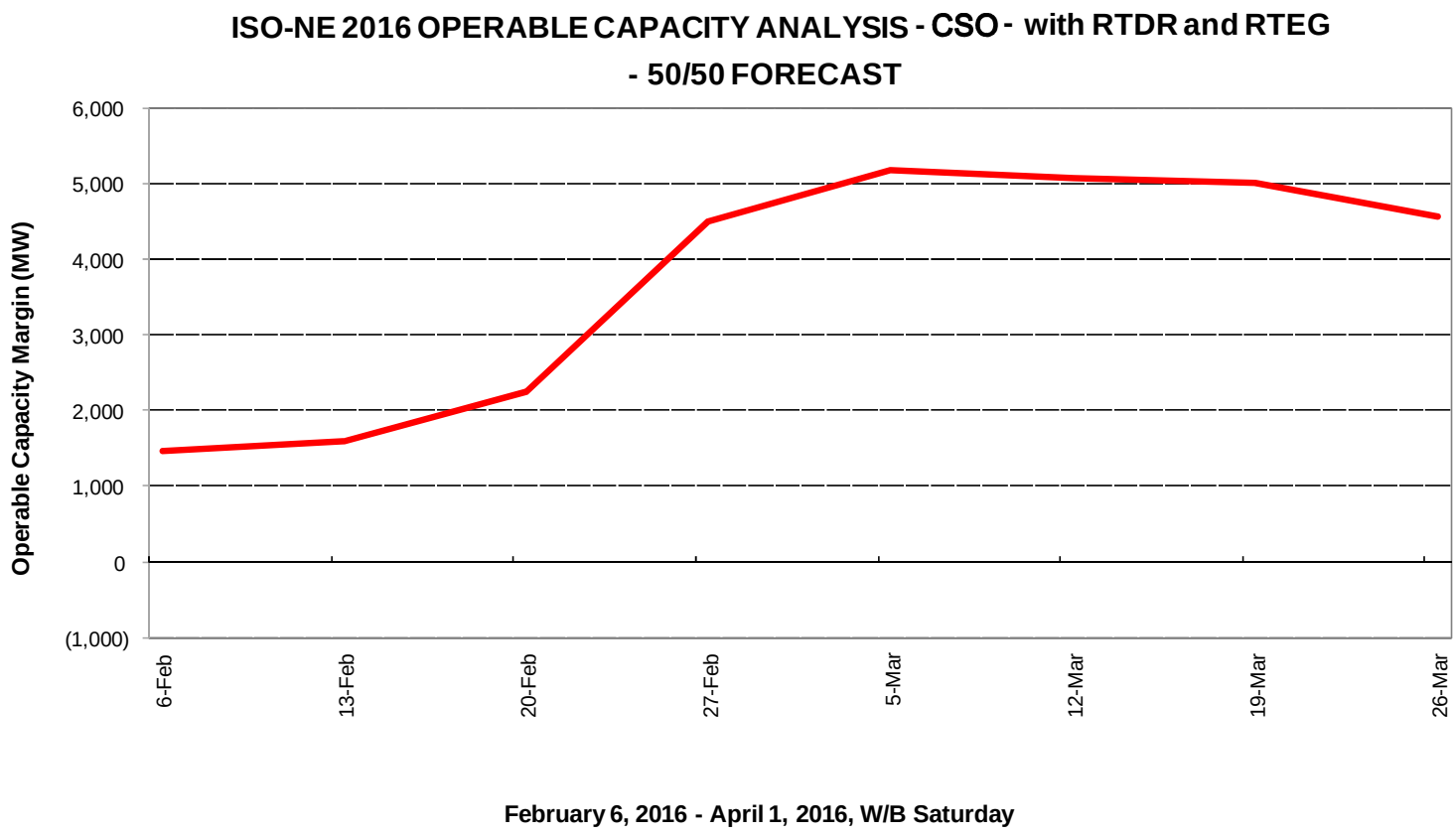
[2] Load based on 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **February 6, 2016**.

[3] Includes OP4 actions associated with RTEG and RTDR

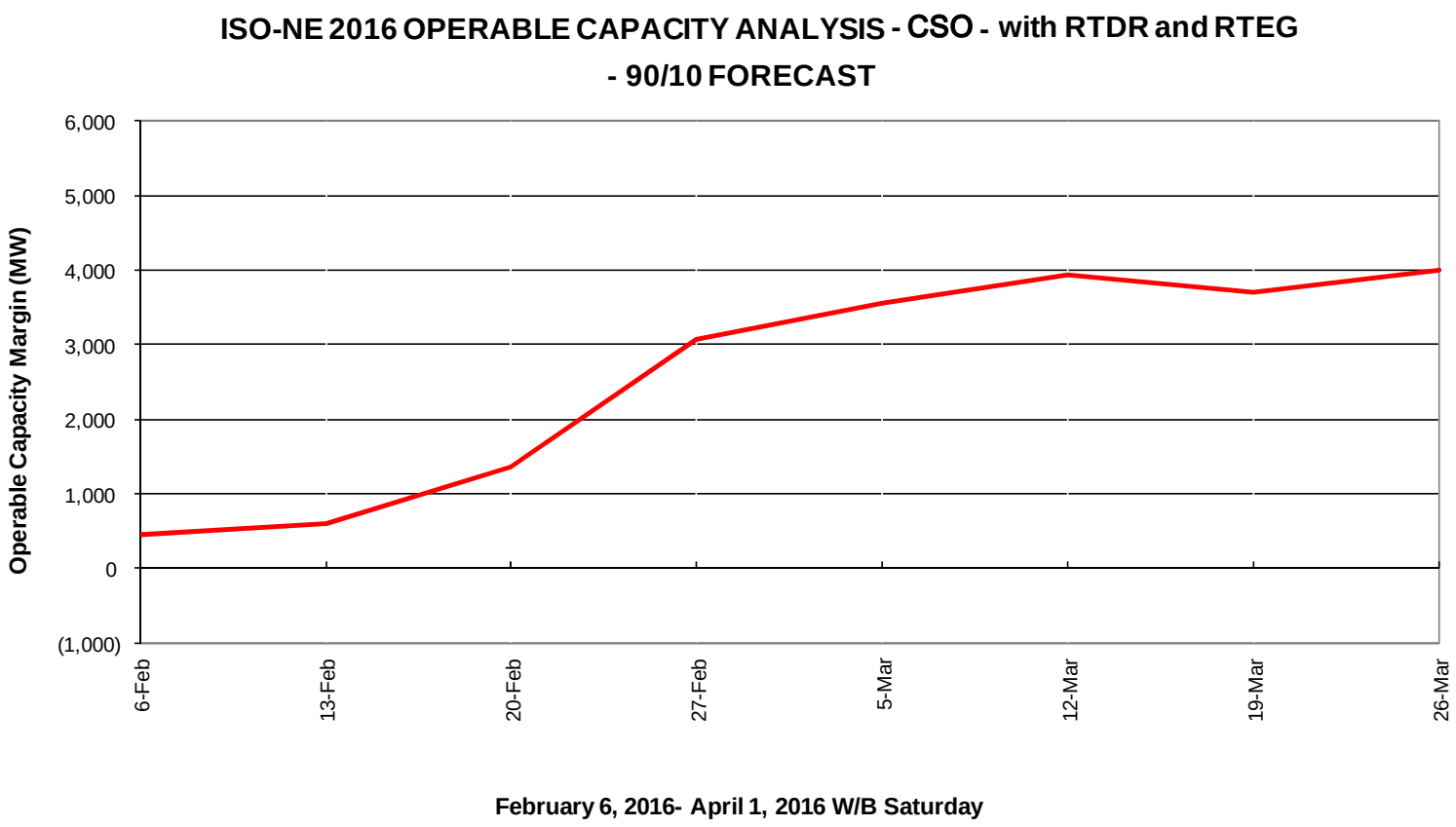
[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Winter 2016 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Winter 2016 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)



Winter 2016 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2016 OPERABLE CAPACITY ANALYSIS

February 5, 2016 - 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 GENERATOR 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]
2/6/2016	30,429	867	15	719	161	3,100	3,407	23,924	20,577	2,305	22,882	1,042	278	1,320	142	1,462
2/13/2016	30,429	867	15	711	161	3,100	3,320	24,019	20,547	2,305	22,852	1,167	278	1,445	142	1,587
2/20/2016	30,429	867	15	395	161	3,100	3,233	24,422	20,279	2,305	22,584	1,838	278	2,116	142	2,258
2/27/2016	30,014	1,156	17	760	161	2,200	2,554	25,512	19,269	2,305	21,574	3,938	375	4,313	174	4,487
3/5/2016	30,014	1,156	17	875	1,317	2,200	945	25,850	18,912	2,305	21,217	4,633	375	5,008	174	5,182
3/12/2016	30,014	1,156	17	1,646	1,077	2,200	733	25,531	18,712	2,305	21,017	4,514	375	4,889	174	5,063
3/19/2016	30,014	1,156	17	2,975	661	2,200	244	25,107	18,339	2,305	20,644	4,463	375	4,838	174	5,012
3/26/2016	30,014	1,156	17	3,431	982	2,700	0	24,074	17,762	2,305	20,067	4,007	375	4,382	174	4,556

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4. 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.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
7. 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.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. 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
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. 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.
16. 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).

Winter 2016 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2016 OPERABLE CAPACITY ANALYSIS

February 5, 2016 - 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 GENERATOR 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]
2/6/2016	30,429	867	15	719	161	3,100	3,761	23,570	21,222	2,305	23,527	43	278	321	142	463
2/13/2016	30,429	867	15	711	161	3,100	3,671	23,668	21,192	2,305	23,497	171	278	449	142	591
2/20/2016	30,429	867	15	395	161	3,100	3,491	24,164	20,916	2,305	23,221	943	278	1,221	142	1,363
2/27/2016	30,014	1,156	17	760	161	2,200	3,356	24,710	19,877	2,305	22,182	2,528	375	2,903	174	3,077
3/5/2016	30,014	1,156	17	875	1,317	2,200	1,965	24,830	19,509	2,305	21,814	3,016	375	3,391	174	3,565
3/12/2016	30,014	1,156	17	1,646	1,077	2,200	1,268	24,996	19,303	2,305	21,608	3,388	375	3,763	174	3,937
3/19/2016	30,014	1,156	17	2,975	661	2,200	981	24,370	18,920	2,305	21,225	3,145	375	3,520	174	3,694
3/26/2016	30,014	1,156	17	3,431	982	2,700	0	24,074	18,325	2,305	20,630	3,444	375	3,819	174	3,993

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4. 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.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
7. 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.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. 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
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. 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.
16. 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

Spring 2016

Spring 2016 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2016[2] CSO	May - 2016[2] SCC
Generator Operable Capacity MW [1]	29,768	32,814
OP CAP From OP-4 RTDR (+)	431	431
OP CAP From OP-4 RTEG (+)	192	192
Operable Capacity Generator with OP-4 DR and RTEG	30,391	33,437
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	950	950
Non Commercial Capacity (+)	17	17
Non Gas-fired Planned Outage MW (-)	3,690	4,185
Gas Generator Outages MW (-)	932	995
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,336	25,824
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,157	20,157
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,462	22,462
Operable Capacity Margin [3]	874	3,362

[1] Generator Operable Capacity is based on data as of **January 19, 2016** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. SCC value is based on data as of **January 19, 2016**

[2] Load based on 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **May 7, 2016**.

[3] Includes OP4 actions associated with RTEG and RTDR

[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Spring 2016 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May- 2016[2] CSO	May - 2016[2] SCC
Generator Operable Capacity MW [1]	29,768	32,814
OP CAP From OP-4 RTDR (+)	431	431
OP CAP From OP-4 RTEG (+)	192	192
Operable Capacity Generator with OP-4 DR and RTEG	30,391	33,437
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	950	950
Non Commercial Capacity (+)	17	17
Non Gas-fired Planned Outage MW (-)	3,690	4,185
Gas Generator Outages MW (-)	932	995
Allowance for Unplanned Outages (-) [5]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [4]	0	0
Net Capacity (NET OPCAP SUPPLY MW) [3]	23,336	25,824
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,955	21,955
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,260	24,260
Operable Capacity Margin [3]	(924)	1,564

[1] Generator Operable Capacity is based on data as of **January 19, 2016** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. SCC value is based on data as of **January 19, 2016**

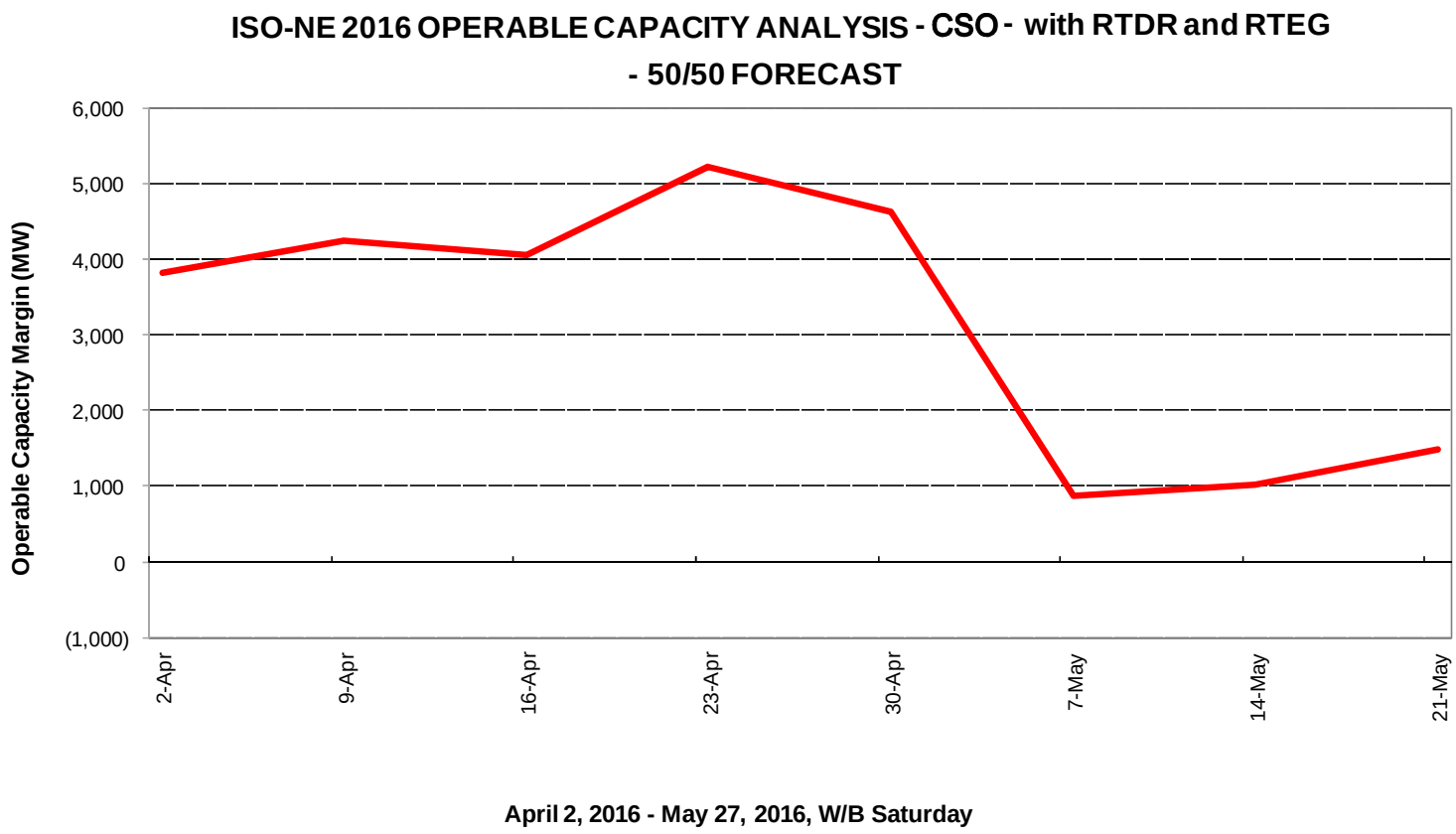
[2] Load based on 2015 CELT report and week with lowest Operable Capacity Margin, week beginning **May 7, 2016**.

[3] Includes OP4 actions associated with RTEG and RTDR

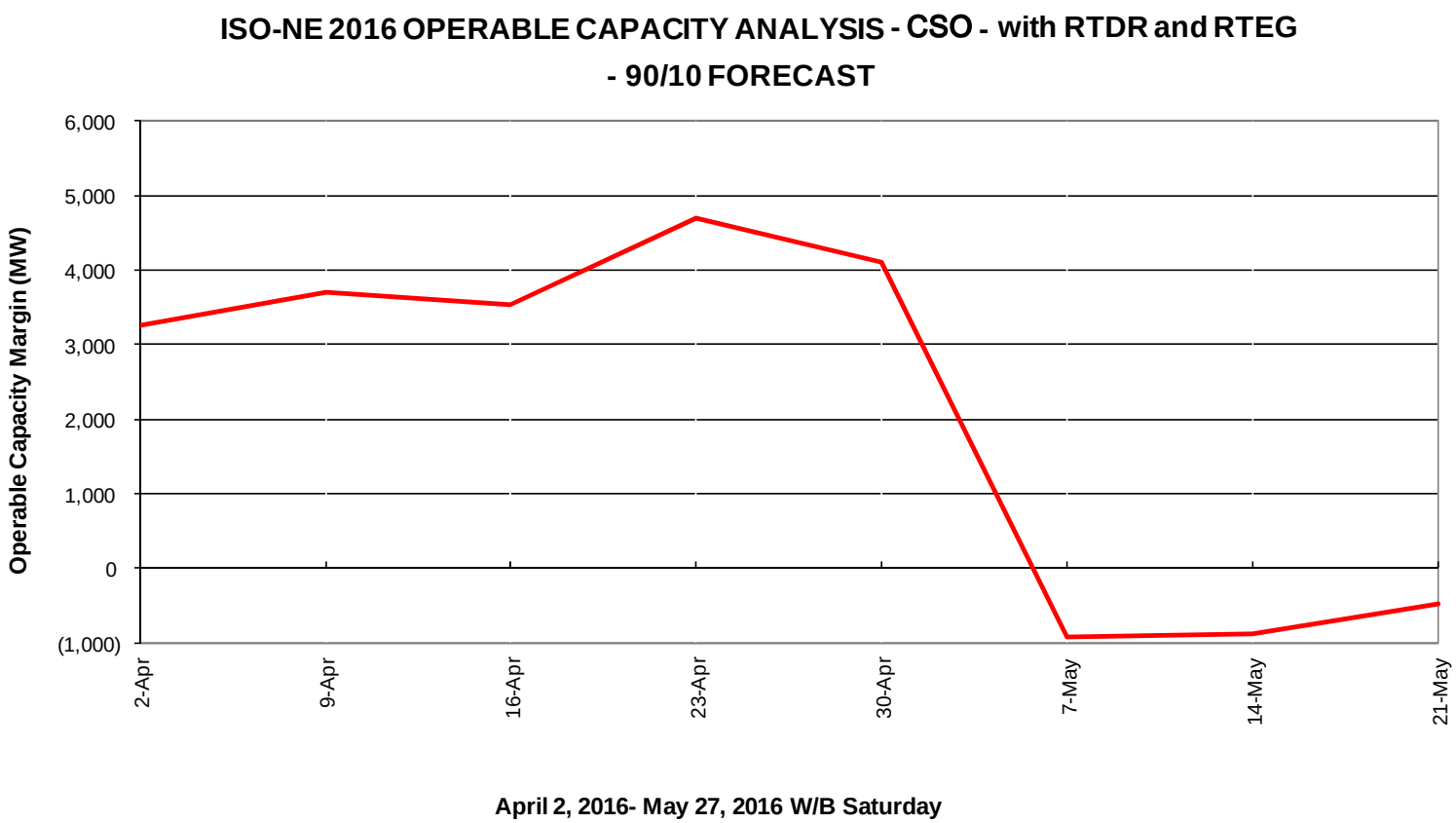
[4] Total of (Gas at Risk MW) – (Gas Gen Outages MW)

[5] Allowance For Unplanned Outage MW is based on the month corresponding to the day with the lowest Operable Capacity Margin for the week.

Spring 2016 Operable Capacity Analysis (MW)
50/50 Forecast (Reference)



Spring 2016 Operable Capacity Analysis (MW)
90/10 Forecast (Extreme)



Spring 2016 Operable Capacity Analysis (MW)

50/50 Forecast (Reference)

ISO-NE 2016 OPERABLE CAPACITY ANALYSIS

February 5, 2016 - 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 GENERATOR 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]
4/2/2016	29,768	950	17	3,583	1,726	2,700	0	22,726	17,235	2,305	19,540	3,186	431	3,617	192	3,809
4/9/2016	29,768	950	17	3,786	1,351	2,700	0	22,898	16,978	2,305	19,283	3,615	431	4,046	192	4,238
4/16/2016	29,768	950	17	4,123	1,716	2,700	0	22,196	16,457	2,305	18,762	3,434	431	3,865	192	4,057
4/23/2016	29,768	950	17	3,533	1,422	2,700	0	23,080	16,186	2,305	18,491	4,589	431	5,020	192	5,212
4/30/2016	29,768	950	17	3,690	1,186	3,400	0	22,459	16,159	2,305	18,464	3,995	431	4,426	192	4,618
5/7/2016	29,768	950	17	3,690	932	3,400	0	22,713	20,157	2,305	22,462	251	431	682	192	874
5/14/2016	29,768	781	17	1,974	1,326	3,400	0	23,866	21,171	2,305	23,476	390	431	821	192	1,013
5/21/2016	29,768	950	17	1,513	548	3,400	0	25,274	22,114	2,305	24,419	855	431	1,286	192	1,478

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4.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.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
7. 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.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. 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
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. 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.
16. 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).

Spring 2016 Operable Capacity Analysis (MW)

90/10 Forecast (Extreme)

ISO-NE 2016 OPERABLE CAPACITY ANALYSIS

February 5, 2016 - 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 GENERATOR 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]
4/2/2016	29,768	950	17	3,583	1,726	2,700	0	22,726	17,784	2,305	20,089	2,637	431	3,068	192	3,260
4/9/2016	29,768	950	17	3,786	1,351	2,700	0	22,898	17,519	2,305	19,824	3,074	431	3,505	192	3,697
4/16/2016	29,768	950	17	4,123	1,716	2,700	0	22,196	16,984	2,305	19,289	2,907	431	3,338	192	3,530
4/23/2016	29,768	950	17	3,533	1,422	2,700	0	23,080	16,705	2,305	19,010	4,070	431	4,501	192	4,693
4/30/2016	29,768	950	17	3,690	1,186	3,400	0	22,459	16,677	2,305	18,982	3,477	431	3,908	192	4,100
5/7/2016	29,768	950	17	3,690	932	3,400	0	22,713	21,955	2,305	24,260	(1,547)	431	(1,116)	192	(924)
5/14/2016	29,768	781	17	1,974	1,326	3,400	0	23,866	23,053	2,305	25,358	(1,492)	431	(1,061)	192	(869)
5/21/2016	29,768	950	17	1,513	548	3,400	0	25,274	24,073	2,305	26,378	(1,104)	431	(673)	192	(481)

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
3. New resources and generator improvements that have acquired a CSO but have not become commercial.
4. 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.
5. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
6. 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.
7. 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.
8. Net OpCap Supply MW Available (1 + 2 + 3 - 4 - 5 - 6 - 7 = 8)
9. 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
10. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
11. Total Net Load Obligation per the formula(9 + 10 = 11)
12. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (8 - 11 = 12)
13. OP 4 Action 2 Real-time Demand Response based on OP4 Appendix A. Reserve Margins and Distribution Loss Factor Gross Ups are Included.
14. OPCAP Margin taking into account Real Time Demand Response through OP4 Step 2 (12 + 13 = 14)
15. 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.
16. 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: 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 [1] 600
2	Dispatch real time Demand Resources.	**February 278[3]** **March 375[3]** **April - May 431[3]**
3	Voluntary Load Curtailment of Market Participants' facilities.	40 [2]
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 [4] **February 142[3]** **March 174[3]** **April - May 192 [3]**

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 January 19, 2016.
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: Appendix A, cont.

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 voluntary provide energy for reliability purposes	0
8	Voltage Reduction requiring 10 minutes or less	269 [4]
9	Transmission Customer Generation Not Contractually Available to Market Participants during a Capacity Deficiency. Voluntary Load Curtailment by Large Industrial and Commercial Customers.	5 200 [2]
10	Radio and TV Appeals for Voluntary Load Curtailment Implement Power Warning	200 [2]
11	Request State Governors to Reinforce Power Warning Appeals.	100 [2]
Total		**February 2,969 MW** **March 3,098 MW** **April - May 3,172 MW**

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 January 19, 2016.
4. The MW values are based on a 26,930 MW system load and the most recent voltage reduction test % achieved.

Quarterly Market Performance Report for 2015 Q3 and Fall (Sept. – Nov.)

NEPOOL Participant Committee Meeting

Jeff McDonald

VICE PRESIDENT, MARKET MONITORING

Highlights for 2015 Q3 (Jul. – Sep.)

- Estimated total wholesale market costs were $1.53 billion, a 7% decrease compared to Q3 2014.
  - Lower natural gas prices were the primary driver for the decrease in total energy costs.
- There was ~ $3/MWh premium in RT LMPs compared to DA.
  - Higher frequency of RT reserve pricing contributed to this premium.
- NCPC payments totaled $28.3 million, a 32% increase from Q3 2014.
  - Primary drivers of increase were (i) several days with low real-time prices and (ii) increased posturing of limited energy resources.

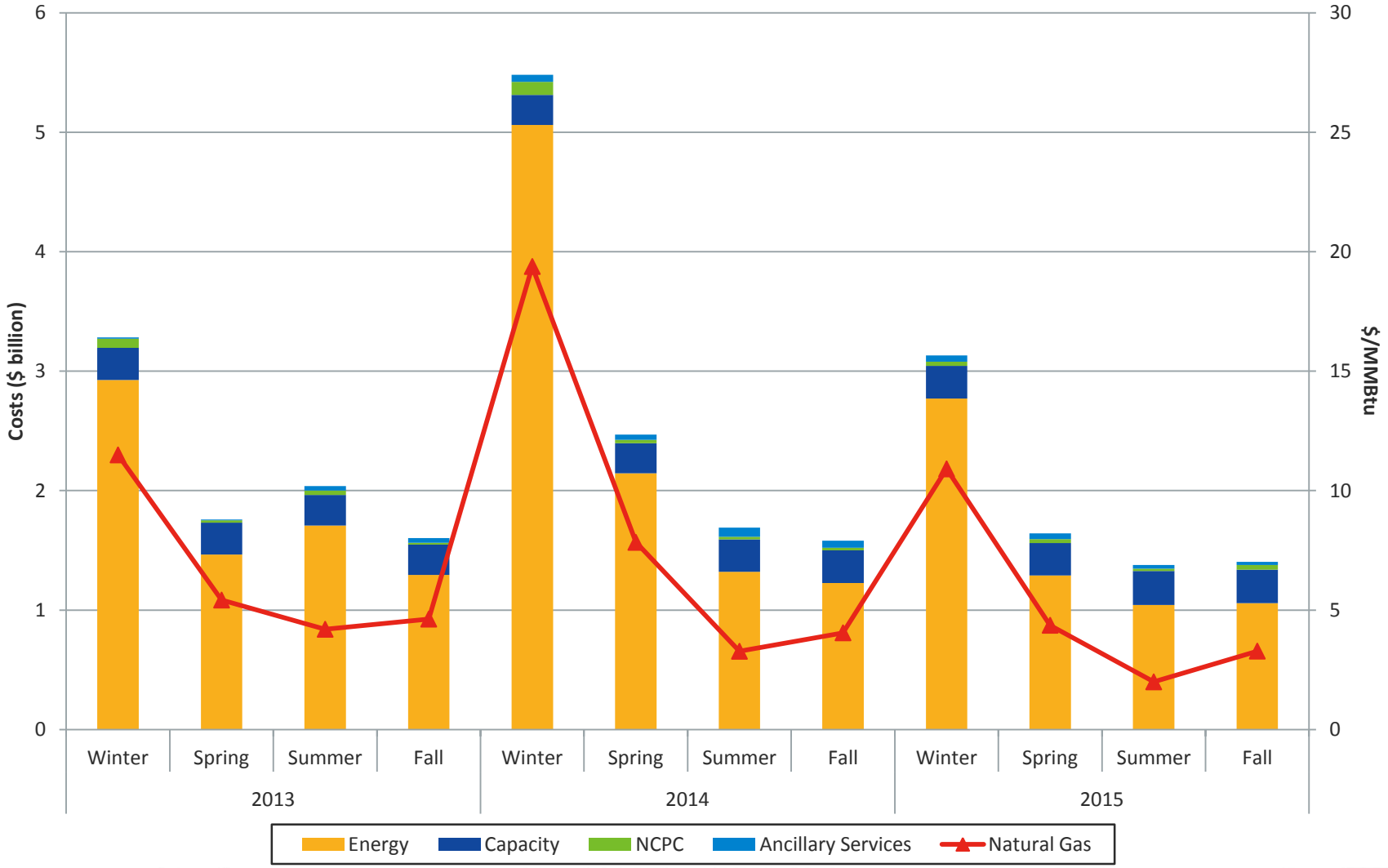
Seasons: Winter: Dec-Feb Spring: Mar-May Summer: Jun-Aug Fall: Sep-Nov

Summary for Fall 2015 (Sep. – Nov.)

- Estimated total wholesale market costs were $1.40 billion, a 11% decrease compared to Fall 2014
  - Lower natural gas prices were the primary driver and load was slightly lower compared to 2014.
- Prices in the DA and RT market were comparable, with a slight DA premium of ~ $1/MWh.
- NCPC payments totaled $40.2 million, an 89% increase from 2014.
  - Lower RT prices resulted in higher RT first contingency NCPC payments
  - Units in NEMA were paid second contingency NCPC for local reliability protection in both the DA and RT markets

Seasons: Winter: Dec-Feb Spring: Mar-May Summer: Jun-Aug Fall: Sep-Nov

Wholesale Market Costs



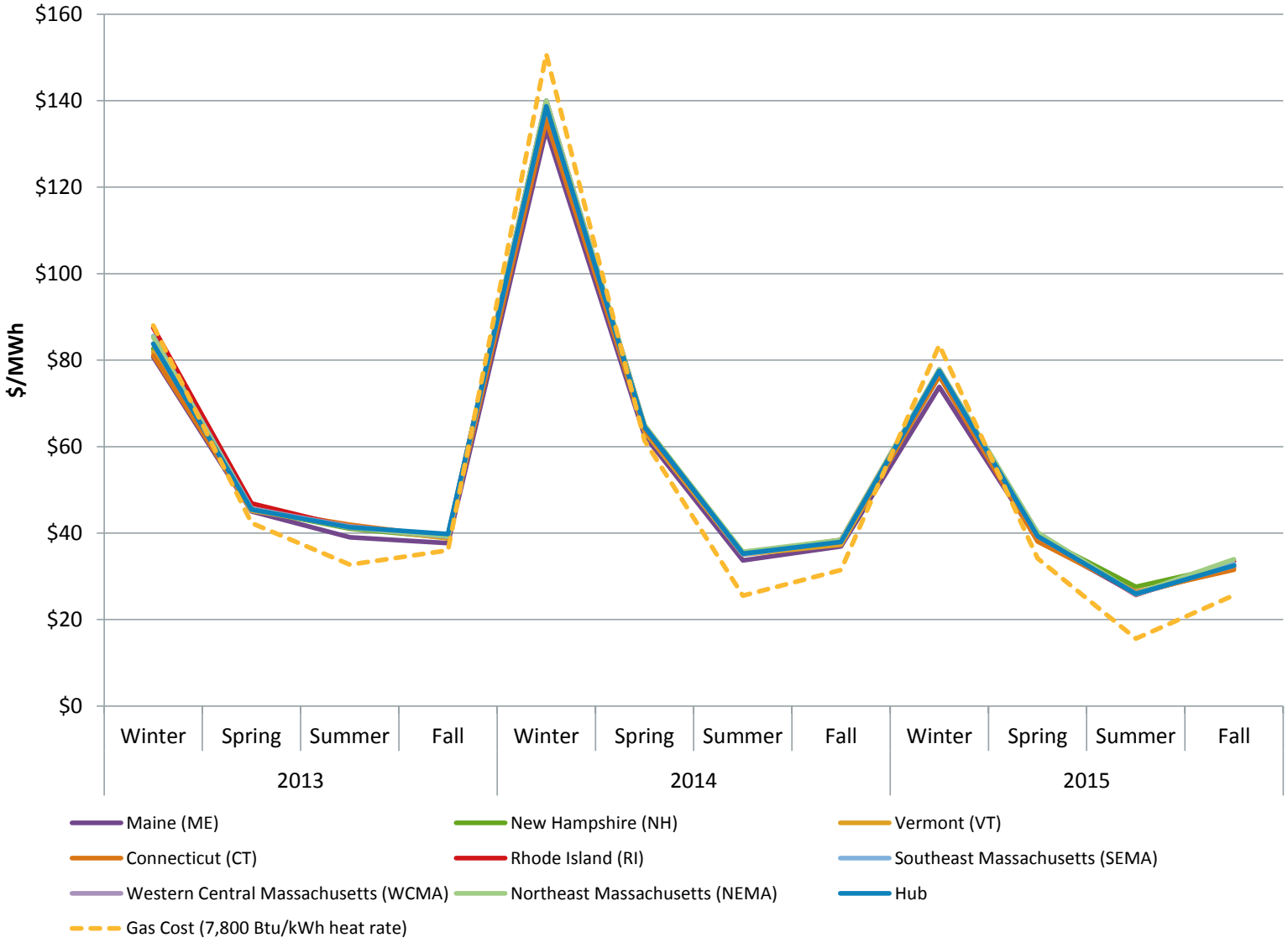
Key Statistics for 2015 Q3

	Q3 2015	Q2 2015	% Change Q3 2015 to Q2 2015	Q3 2014	% Change Q3 2015 to Q3 2014
Real-Time Load (GWh)	34,970	29,114	20%	33,709	4%
Weather Normalized Real-Time Load (GWh)	34,316	29,145	18%	34,075	1%
Peak Real-Time Load (MW)	24,398	20,895	17%	24,443	0%
Average Day-Ahead Hub LMP ($/MWh)	$29.09	$24.84	17%	$33.98	-14%
Average Real-Time Hub LMP ($/MWh)	$32.15	$23.89	35%	$33.70	-5%
Average Natural Gas Price ($/MMBtu)	$2.38	$2.23	6%	$2.98	-20%

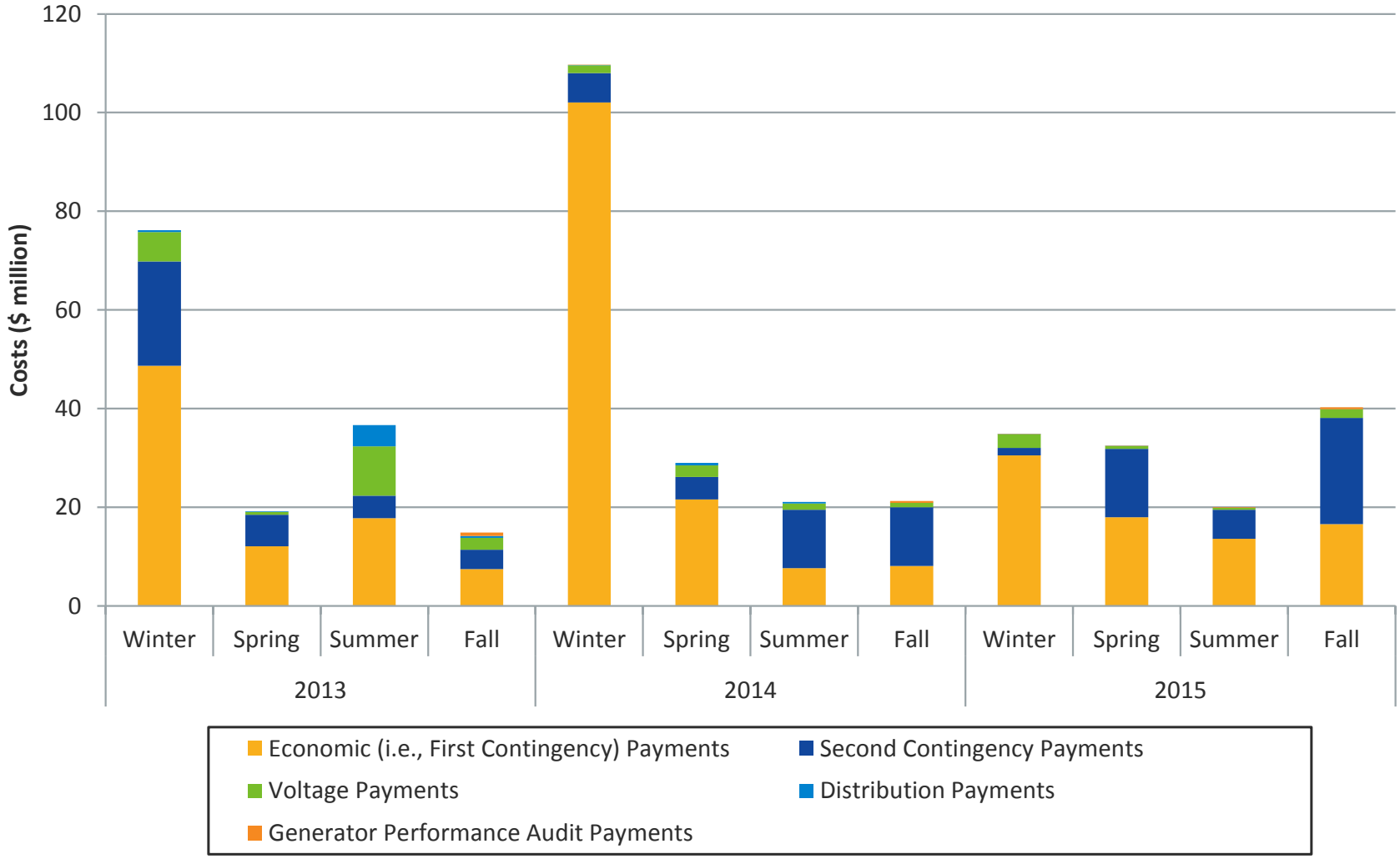
Key Statistics for 2015 Fall

	Fall 2015	Summer 2015	% Change Fall 2015 to Summer 2015	Fall 2014	% Change Fall 2015 to Fall 2014
Real-Time Load (GWh)	29,583	34,459	-14%	29,914	-1%
Weather Normalized Real-Time Load (GWh)	29,317	34,509	-15%	29,550	-1%
Peak Real-Time Load (MW)	24,308	24,437	-1%	23,715	3%
Average Day-Ahead Hub LMP ($/MWh)	$32.47	$25.94	25%	$37.94	-14%
Average Real-Time Hub LMP ($/MWh)	$31.53	$26.86	17%	$37.11	-15%
Average Natural Gas Price ($/MMBtu)	$3.29	$2.00	64%	$4.04	-19%
Average No.6 0.3% Oil Price ($/MMBtu)	$7.67	$9.16	-16%	$14.23	-46%

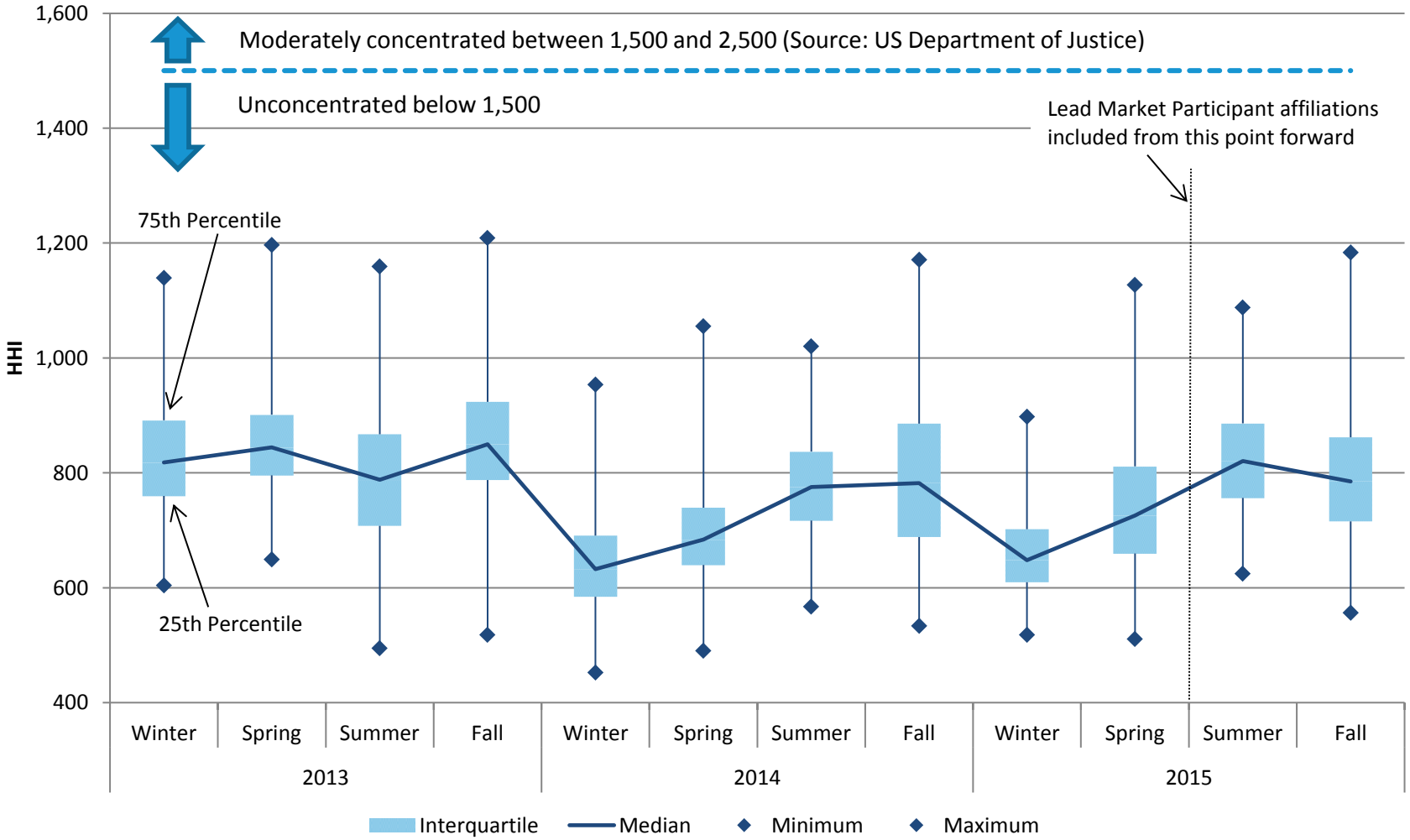
Day-Ahead Prices and Gas Generation Cost



NCPC Payments, 2013-2015

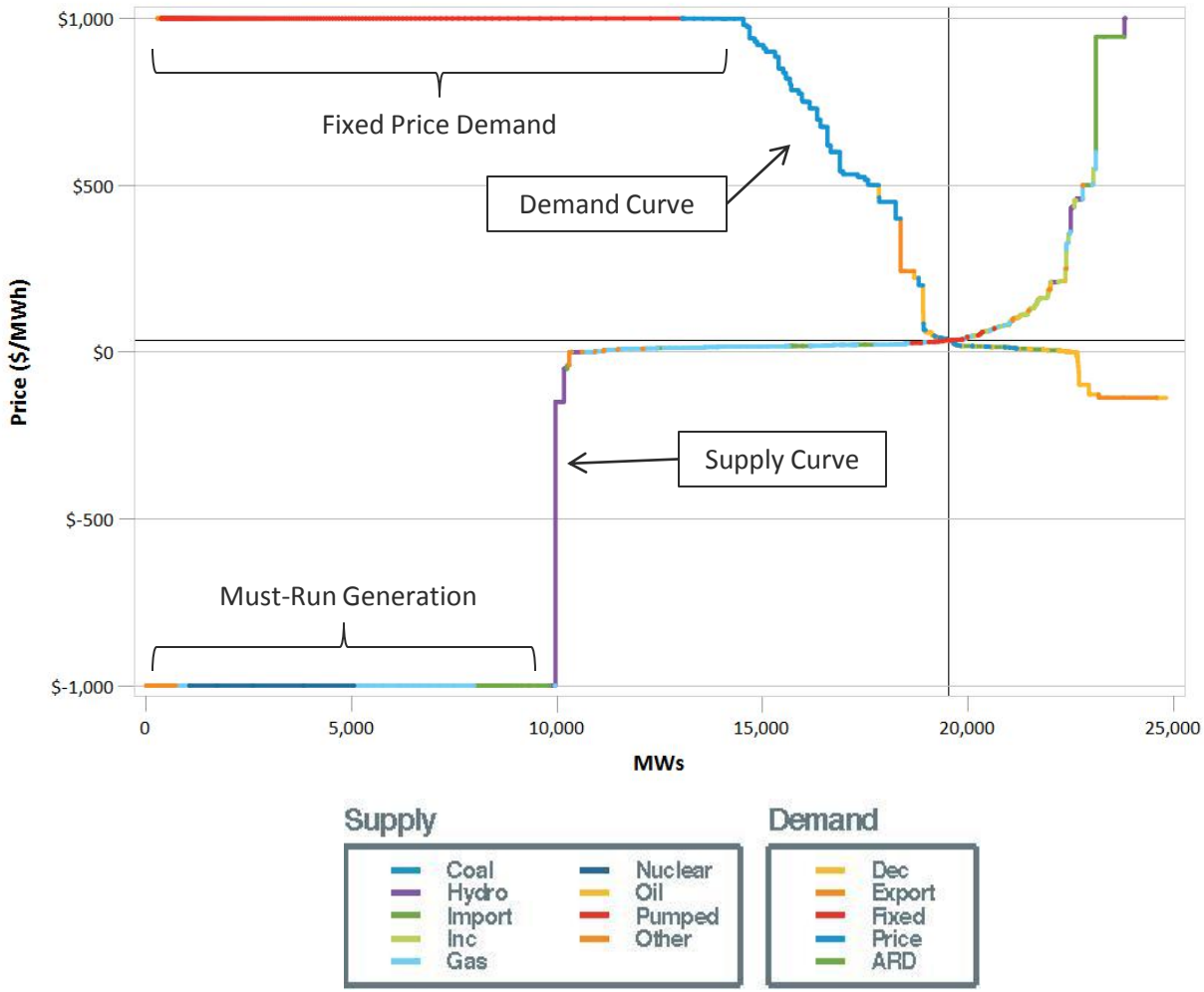


HHI


1,600
1,400
1,200
1,000
800
600
400
HHI
Moderately concentrated between 1,500 and 2,500 (Source: US Department of Justice)
Unconcentrated below 1,500
Lead Market Participant affiliations included from this point forward
75th Percentile
25th Percentile
Winter
Spring
Summer
Fall
Winter
Spring
Summer
Fall
Winter
Spring
Summer
Fall
2013
2014
2015
Interquartile
Median
Minimum
Maximum

Day-Ahead Supply Curve Example

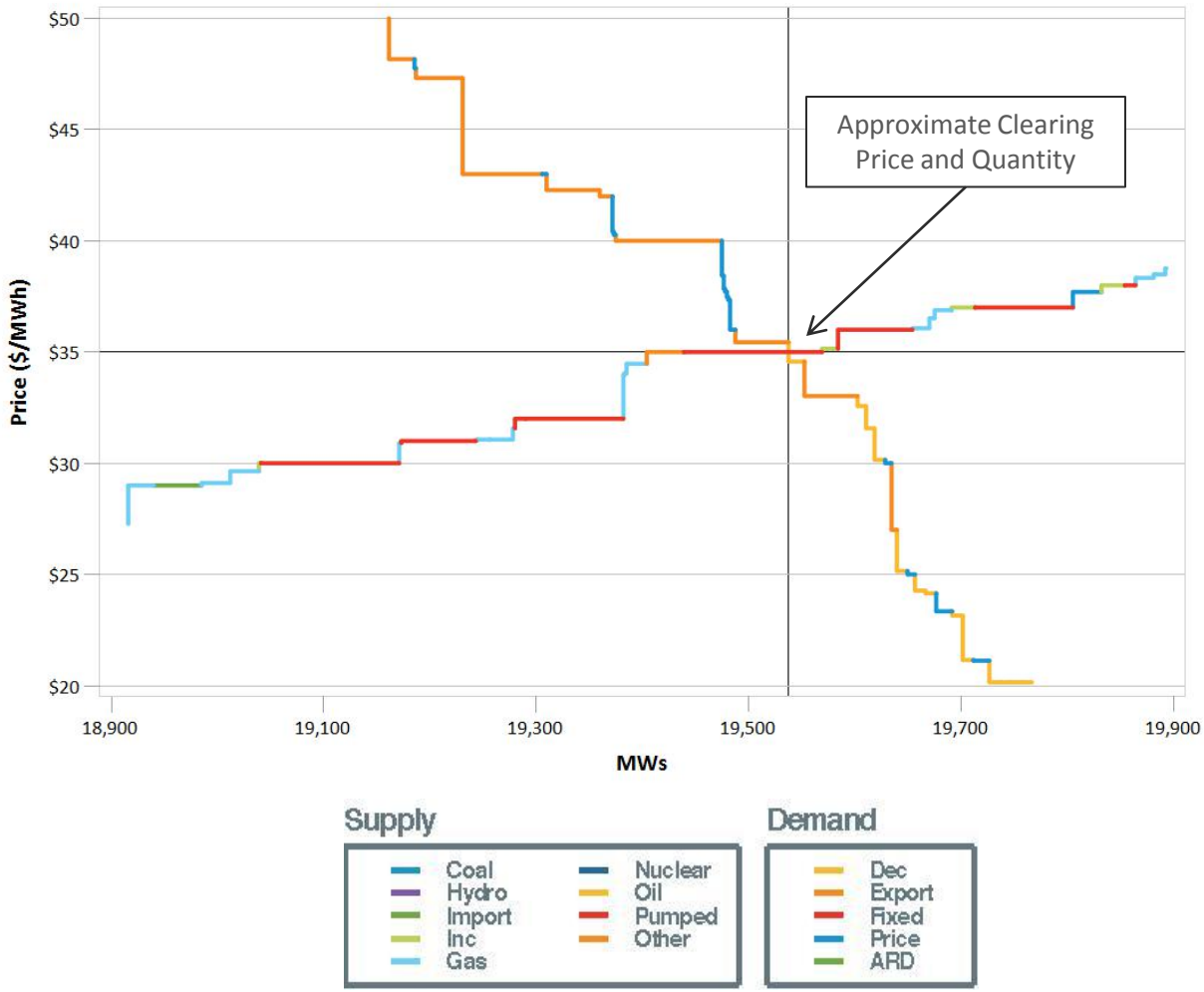
August 1, 2015, Hour Ending 17



- This chart, and the next, illustrate the diversity of resources priced in the neighborhood of the clearing price.

Day-Ahead Supply Curve Example

August 1, 2015, Hour Ending 17 – A closer look



- Within the $10 range around the clearing price, there are virtual demand and supply bids, external transactions, gas, coal, pumped-storage gen, and price-sensitive demand

Questions

ISO New England's Internal Market Monitor

Third Quarter 2015

Quarterly Markets Report

Internal Market Monitor
December 22, 2015

Contents

Preface ..... **v**

Section 1 Executive Summary **7**

1.1 Summary of Market Outcomes and Performance *7*

Section 2 Summary of Market Outcomes and System Conditions **8**

2.1 Market Outcomes *8*

2.2 System Conditions *26*

2.3 Market Competitiveness *30*

Tables

Table 2-1: Key Statistics on Load, LMPs, and Natural Gas 9

Table 2-2: Forward Reserve Requirements for the Winter 2015-2016 LFRM Auction (MW) 22

Table 2-3: Auction Clearing Price, Three-Most-Recent FRM Auctions ($/MW-month) 22

Table 2-4: Acquired and Transferred MW for the September-November 2015 Bilateral Contract Periods 26

Figures

Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Quarter, 2013-2015 ($ billions and $/MMBtu) 9

Figure 2-2: Simple Average Real-Time Prices and Gas Generation Costs by Quarter, 2013-2015 ($/MWh) 10

Figure 2-3: Real-Time Marginal units by fuel type by Quarter, 2013-2015 11

Figure 2-4: Quarter 3 Average Hourly Demand, 2010-2015 (MW) 12

Figure 2-5: Quarter 3 Load Duration Curves, 2013-2015 (MW) 13

Figure 2-6: Real-Time Reserve Payments by Quarter, 2013- 2015 ($ millions) 14

Figure 2-7: Regulation Payments by Quarter, 2013- 2015 ($millions) 15

Figure 2-8: Simple Average Day-Ahead Prices and Gas Generation Costs by Quarter, 2013-2015 ($/MWh) 16

Figure 2-9: Day-Ahead Marginal units by type by Quarter, 2013-2015 17

Figure 2-10: Total Offered and Cleared Virtual Transactions by Quarter, 2013-2015 (average hourly MW) 17

Figure 2-11: Day-Ahead Market Aggregate Supply and Demand Curves for August 1, 2015, Hour Ending 17 19

Figure 2-12: Intersection of the Day-Ahead market aggregate supply and demand curves for August 1, 2015, hour ending 17 20

Figure 2-13: Total Capacity Payments by Quarter, 2013-2015 (millions of $) 24

Figure 2-14: Bid/Offered and Cleared MW, September-November 2015 Monthly Reconfiguration Auctions 25

Figure 2-15: NCPC Payments by Quarter and Category, 2013-2015 ($ millions) 28

Figure 2-16: September 9, 2015 Real-Time Hub LMPs and TMSR Prices ($/MWh) 29

Figure 2-17: Imports, Exports, and Net Interchange by Quarter, 2013-2015 (Average hourly MW) 29

Figure 2-18: Hourly HHI by Month, September 2014-September 2015 31

Preface

The Internal Market Monitor ("IMM") of ISO New England Inc. (the "ISO") publishes a Quarterly Markets Report that assesses the state of competition in the wholesale electricity markets operated by the ISO. 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, Appendix A, Section III.A.17.2.2, *Market Monitoring, Reporting, and Market Power Mitigation*:

> The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A.***

This report covers the period from July 1, 2015 to September 30, 2015 (the "Reporting Period"). The report contains our analyses and summaries of market performance. All information and data presented here are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.[1]

Underlying natural gas data furnished by:

[1] Capitalized terms not defined herein have the meanings ascribed to them in Section I of the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the "Tariff").

Oil prices are provided by Argus Media.[2]

[2] *Available at* http://www.theice.com.

Section 1
Executive Summary

The Internal Market Monitor has analyzed the performance in the third quarter ("Q3") of 2015 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. A summary of market conditions and outcomes is provided in this report. Overall, market prices reflected the cost of providing energy, and energy market outcomes were competitive.

1.1 Summary of Market Outcomes and Performance

- The total estimated wholesale market costs were $1.53 billion in the Reporting Period, a 7% decrease compared to the same period in 2014 (Q3 2014).
    - Lower natural gas prices were the primary driver for the decrease in total energy costs. Natural gas prices averaged $2.38/MMBtu. This is a 20% decrease from Q3 2014.
- In Q3 2015, the average hourly demand was 15,838 MW, compared to 15,261 MW in the same quarter of 2014. One significant factor contributing to the year-over-year increase in energy consumption was warmer weather in 2015 for the period when compared to the cooler summer of 2014.
- Day-Ahead Energy Market prices averaged $29.09/MWh at the Hub and Real-Time prices averaged $32.15/MWh. The separation of Real-Time and Day-Ahead prices was due, in part, to the frequency of Real-Time reserve pricing during the Reporting Period. Day-Ahead prices were 14% lower than Q3 2014, and Real-Time prices were 5% lower than Q3 2014.
- Total Real-Time reserve payments were $18.9 million, a $7 million increase from Q3 2014, and Regulation payments totaled $6.3 million, a $2.0 million increase from Q3 2014.
- The winter 2015 locational Forward Reserve Auction cleared with a clearing price of $5,434/MW-month for all reserve zones and products.
- Net Commitment Period Compensation (NCPC) payments totaled $28.3 million, a 32% increase from Q3 2014. The majority of NCPC incurred during the Reporting Period was for first contingency. The increase in Economic NCPC payments compared to Q3 2014 was largely attributable to several days with suppressed Real-Time prices compared to Day-Ahead prices and posturing of limited energy generating resources.
- Overall, the energy market was competitive. The system-wide concentration of supply ownership remains low. Energy market prices are consistent with input costs.

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 in the Reporting Period.

2.1 Market Outcomes

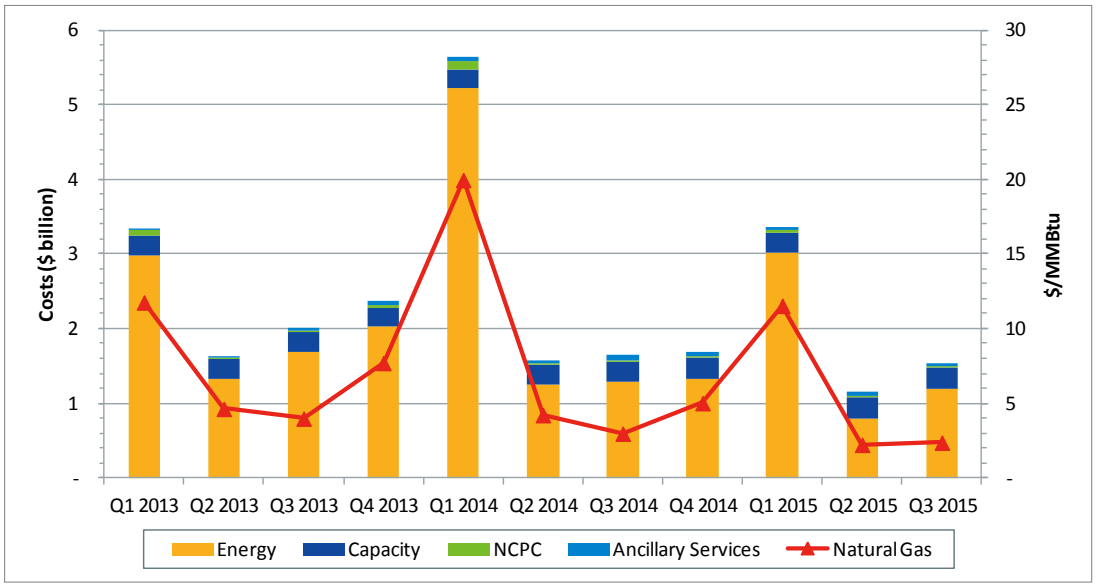
2.1.1 Total Wholesale Electricity Market Value

Figure 2-1 below shows the estimated wholesale electricity cost for each quarter (in billions of dollars) by market, along with average natural gas prices (in $/MMBtu). In Q3 2015, the total estimated market cost decreased by about 7% compared to the same quarter last year ($1.53 billion compared to $1.66 billion in Q3 2014), and increased by 34% when compared to Q2 2015 ($1.14 billion).[3] Net Commitment Period Compensation (NCPC) costs in Q3 2015, at $28 million, increased by 5% compared to Q2 2015 and increased by 32% compared to Q3 2014. Ancillary service costs, which include regulation and forward and real-time reserve payments, totaled $36 million in Q3 2015, a decrease of 55% when compared to Q2 2015 and a decrease of 15% when compared to Q3 2014, respectively.

As shown in Figure 2-1, natural gas prices were a key driver behind changes in energy costs. The increase in natural gas prices, together with the higher demand for electricity during the summer months, resulted in an increase in energy costs in Q3 2015 compared to Q2 2015. Compared to Q3 2014, gas prices were lower in Q3 2015, resulting in lower energy costs.

[3] The total cost of electric energy is approximated as the product of the Day-Ahead load obligation for the region and the average Day-Ahead locational marginal price (LMP) plus the product of the Real-Time load deviation for the region and the average Real-Time LMP. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of annual wholesale costs.

Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Quarter, 2013-2015 ($ billions and $/MMBtu)



2.1.2 Key Market Statistics

Table 2-1 shows selected key statistics for load levels, Real-Time and Day-Ahead Energy Market prices, and fuel prices.

Table 2-1: Key Statistics on Load, LMPs, and Natural Gas

	Q3 2015	Q2 2015	Percent Change Q3 2015 to Q2 2015	Q3 2014	Percent Change Q3 2015 to Q3 2014
Real-Time Load (GWh)	34,970	29,114	20%	33,709	4%
Weather Normalized Real-Time Load (GWh)	34,316	29,145	18%	34,075	1%
Peak Real-Time Load (MW)	24,398	20,895	17%	24,443	0%
Average Day-Ahead Hub LMP ($/MWh)	$29.09	$24.84	17%	$33.98	-14%
Average Real-Time Hub LMP ($/MWh)	$32.15	$23.89	35%	$33.70	-5%
Average Natural Gas Price ($/MMBtu)	$2.38	$2.23	6%	$2.98	-20%

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 third quarter of 2015 were 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 20% from Q3 2014.
    - Oil prices were also 56% lower during the Reporting Period compared to Q3 2014.
- The Real-Time Load in Q3 2015 was 4% higher than the Real-Time load in Q3 2014.

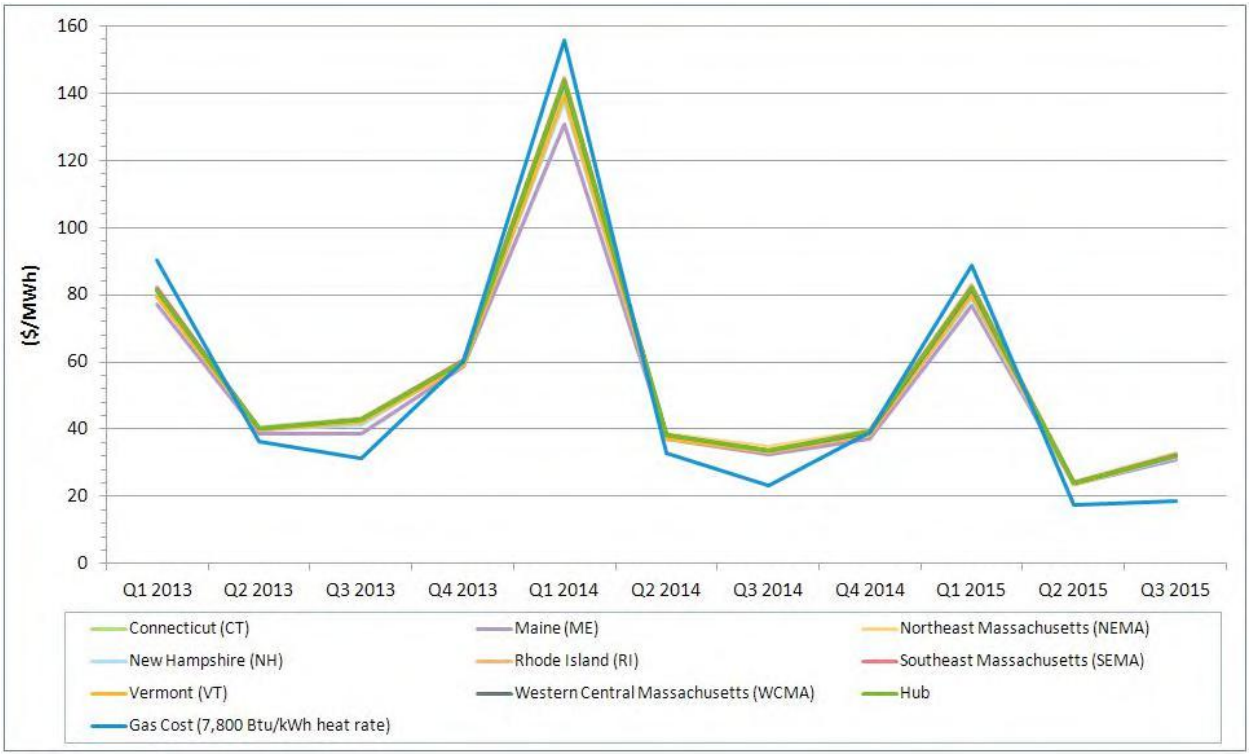
- The peak Real-Time Load, which occurred on July 20, 2015 during the Reporting Period, was 24,398 MW, 0.2% lower than the peak load observed in Q3 2014.

2.1.3 Real-Time Markets

2.1.3.1 Real-Time Energy Market

The average Real-Time hub price was $32.15/MWh in the Reporting Period, a 35% increase over the historic low of $23.89/MWh in Q2 2015. Real-Time prices stayed correlated with the cost of natural gas which also remained at comparatively low levels (see Table 2-1). Prices did not differ significantly among the load zones.[4] Figure 2-2 below shows the quarterly average Real-Time energy prices and the estimated cost of gas generation (assuming a unit heat rate of 7,800 Btu/kWh and the Algonquin Citygate index price).

Figure 2-2: Simple Average Real-Time Prices and Gas Generation Costs by Quarter, 2013-2015 ($/MWh)

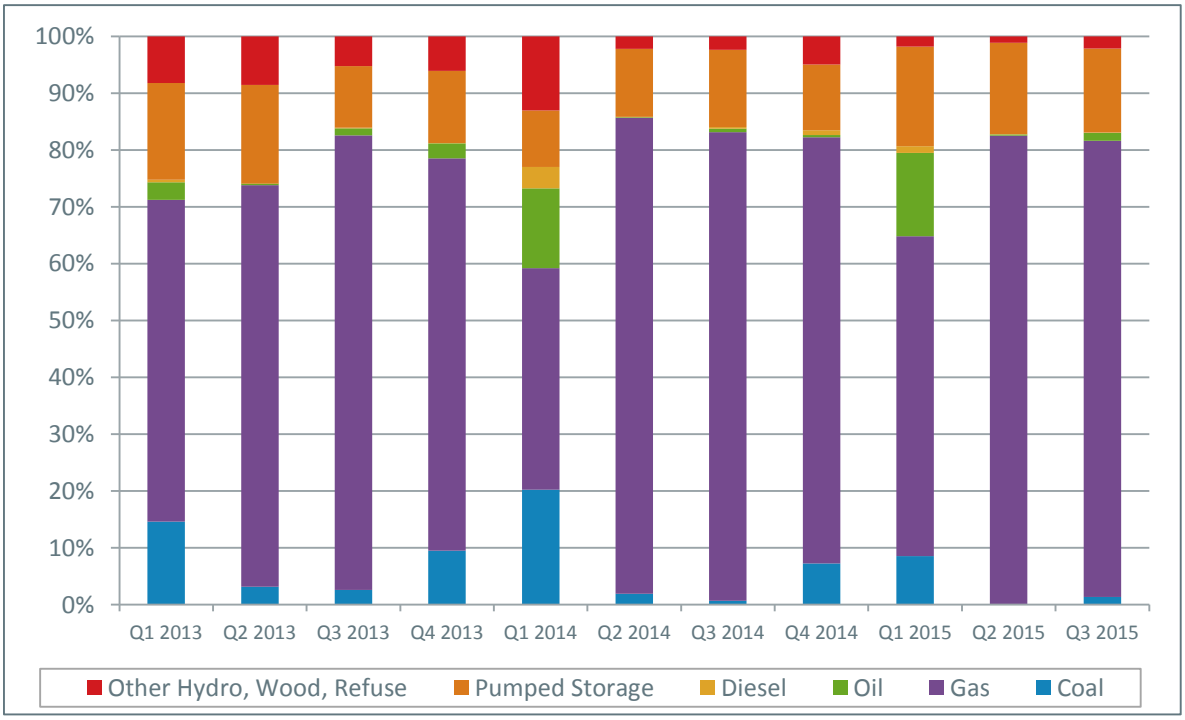


As Figure 2-2 shows, average Real-Time energy prices rose in the Reporting Period compared to the previous quarter. The average hub price was up 35% over Q2 2015, but 5% lower than Q3 2014. Energy prices continued to track the cost of natural gas-fired generation, which also was up slightly, as shown by the movement in the zonal energy price trend lines and the blue gas cost trend line. However, energy prices exhibited a positive divergence from gas generation costs similar to those observed in Q3 2013 and Q3 2014. Several factors contributed to this divergence, including higher loads (Section 2.1.3.2), oil and coal resources being economic at times and setting price more frequently (Figure 2-3), and Real-Time reserve pricing (Section 2.1.3.3).

[4] A *load zone* is an aggregation of pricing nodes within a specific area; there are currently eight load zones in the New England region that correspond to the reliability regions.

In the Reporting Period, units burning natural gas were marginal (*i.e.*, setting the price) for 80% of the pricing intervals, followed by pump storage units (including pumping demand) which were marginal for 15% of the pricing intervals. Units burning coal, oil, diesel, jet fuel, wood, and traditional hydro units were marginal in the remaining pricing intervals. Figure 2-3 below shows the percentages of marginal fuels since Q1 2013.

Figure 2-3: Real-Time Marginal units by fuel type by Quarter, 2013-2015

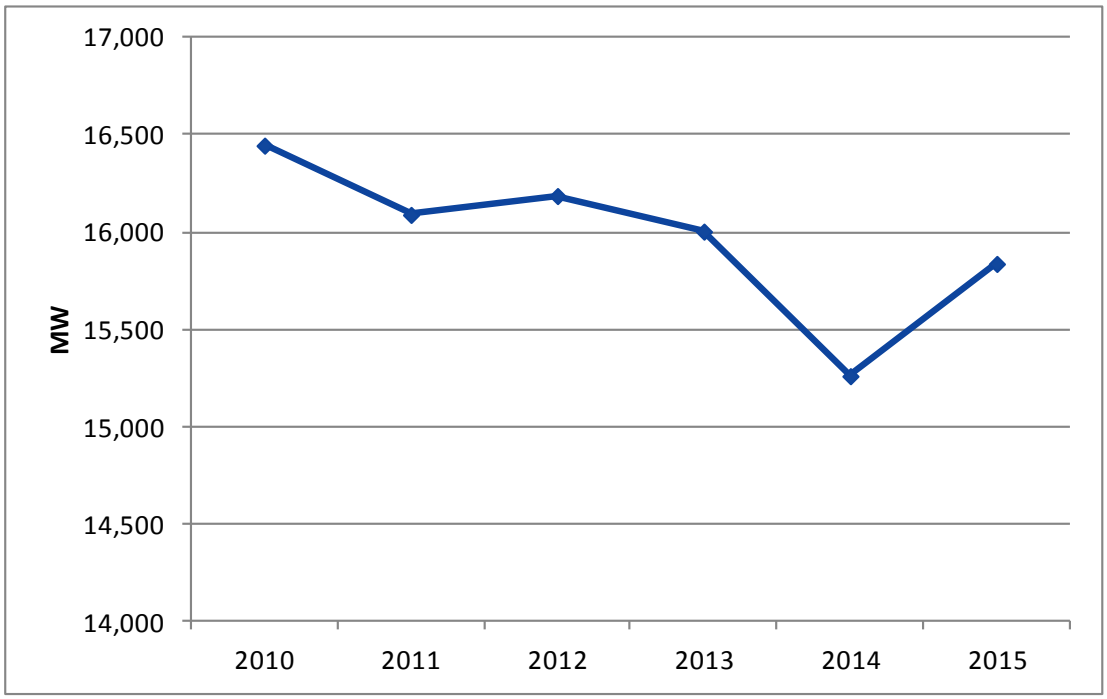


2.1.3.2 Load Summary

In the Reporting Period, the average hourly demand was comparable to prior third quarters as shown in Figure 2-4. In Q3 2015, the average hourly demand was 15,838 MW, compared to 15,261 MW in the third quarter of 2014.[5] One significant factor contributing to the year-over-year increase in energy consumption was warmer weather in 2015 for the period when compared to the cooler summer of 2014.

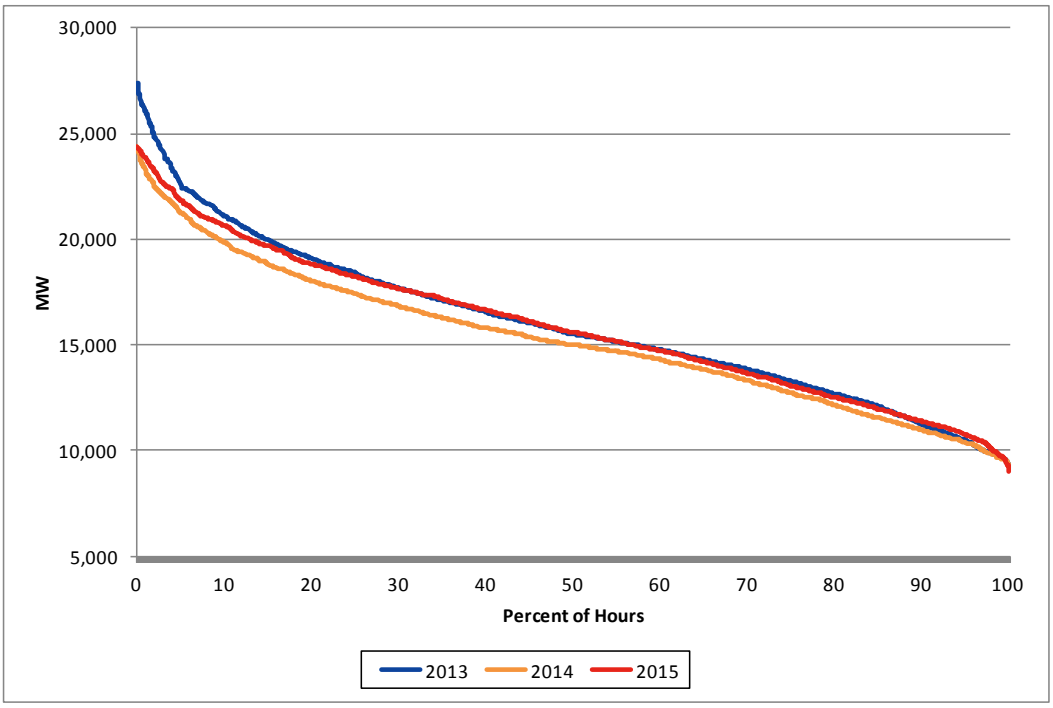
[5] The terms "demand" and "load" are used interchangeably and are intended to have the same meaning in this report.

Figure 2-4: Quarter 3 Average Hourly Demand, 2010-2015 (MW)



Another way to examine load is to take all hourly loads in the quarter (i.e. 2,208 hourly values in the Reporting Period) and sort them from highest to lowest. The resulting curve is called a *load duration curve.* By plotting several load duration curves by year, one can easily observe differences between years for the time period of interest, in this case for Q3. Also, since the load duration curves have the same number of observations (hours), the horizontal axis can be expressed in percent over the period of interest as seen in Figure 2-5. The percent axis allows one to quickly view what percent of hours are above or below a particular load level.

Figure 2-5: Quarter 3 Load Duration Curves, 2013-2015 (MW)



The peak occurred on July 20 at 5:00 PM in the Reporting Period and was 24,398 MW, similar in magnitude to the Q3 2014 peak of 24,443 MW. The Q3 2014 peak load also occurred in July. In the Reporting Period, approximately 13 percent of the hourly demands exceeded 20,000 MW. Total energy sales were 34,971 GWh for the Reporting Period, an increase of 3.8% compared to Q3 2014's sales of 33,696 GWh. The increase in energy sales can be attributed to warmer weather in the Reporting Period relative to Q3 2014.

In contrast, the lowest hourly demand occurred at 4:00 AM on September 27 at 9,019 MW in the Reporting Period.

2.1.3.3 Real-Time Operating Reserves

In the Reporting Period, total Real-Time reserve payments were $18.9 million; a $7.0 million increase relative to Q3 2014's $11.9 million of payments.[6] The increase in total payments compared to Q3 2014 was primarily the result of higher average ten-minute spinning reserve (TMSR) prices and an increase in the frequency of non-zero reserve prices for both ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR). Real-Time reserve payments also increased from Q2 2015 to Q3 2015, which resulted from both an increase in the pricing frequency for the TMNSR and TMOR products (from 0.47% to 1.80% and 0.45% to 1.78% of intervals, respectively) and an increase in the average TMSR prices.

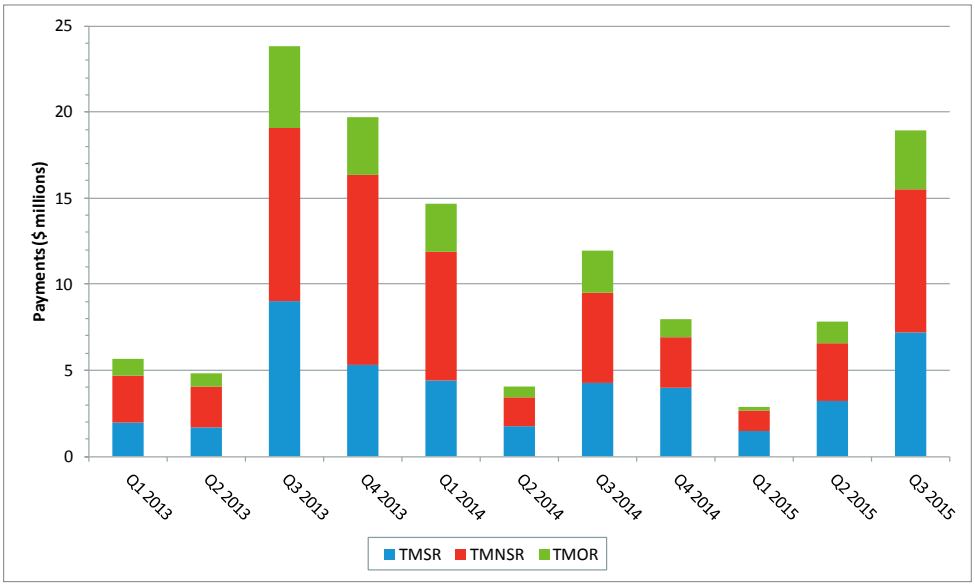
Higher average reserve pricing represents increased opportunity costs for generators that must be redirected away from providing energy to satisfy reserve requirements. Due to the increase in frequency of reserve pricing during the Reporting Period, average Real-Time LMPs also increased

[6] Payment data represent total payments for Real-Time reserves, and are not net of settlement adjustments for forward reserve obligation charges.

(Section 2.1.3.1) and were, on average about 10%, or $3/MWh above Day-Ahead LMPs.[7] Higher than average temperatures during the last month of the quarter resulting in several days with loads over the forecast and tight system conditions, which contributed to the increase in reserve pricing frequency.

As shown in Figure 2-6, operating reserve payments vary significantly over time. This is the result of a variety of factors including system conditions, fuel prices and Real-Time LMP variation, and changes to operating reserve requirement and pricing rules.

Figure 2-6: Real-Time Reserve Payments by Quarter, 2013- 2015 ($ millions)



2.1.3.4 Regulation Market

Total Regulation Market payments were $6.3 million during the Reporting Period, up 56% from $4.0 million in Q2 2015, and up 46% from $4.3 million in Q3 2014.The results appear to continue two trends:

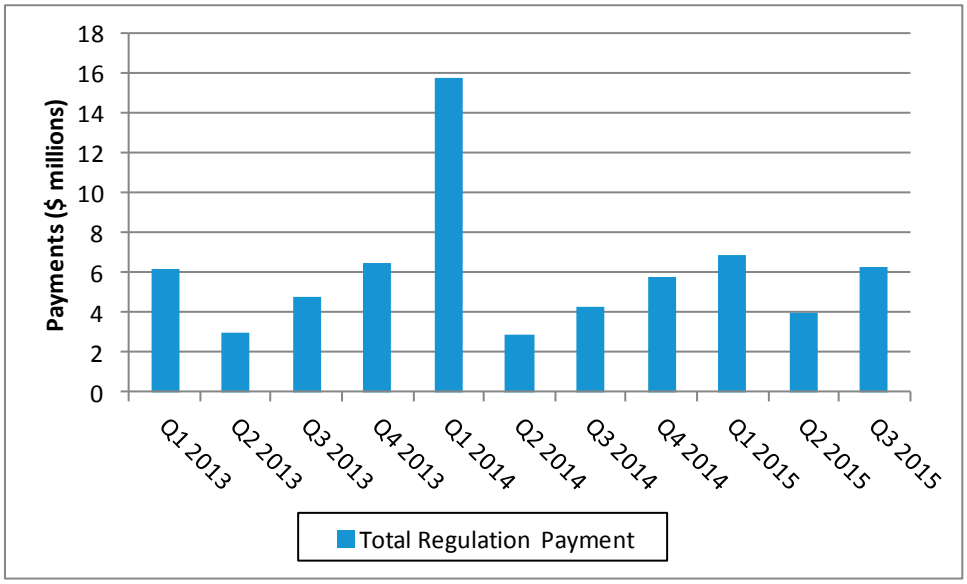
- seasonality in payments, with the lowest payments occurring in Q2 and increasing through Q1 of the following year; and
- increased total regulation payments (compared to the same quarters in prior years) with the implementation of the market redesign beginning in Q2 2015.[8]

[7] Note that increased Reserve Constraint Penalty Factors (implemented just prior to Q1 2015) might also explain a small portion of the increase in payments, when comparing Q3 2014 to Q3 2015.

[8] On March 31, ISO New England's redesigned regulation market went into effect. The changes were a result of FERC Order 755 requiring two-part bidding and compensation of frequency regulation resources to be based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service. The rule changes included the introduction of a two-part methodology for offer and clearing prices. The regulation self-schedule concept was also eliminated. Resources now submit both a regulation capacity ($/MW) and service ($/MW-mile) offer price. The ISO's least cost optimization produces a corresponding clearing price for capacity, which includes the opportunity costs of the marginal unit, and a clearing price for service.

Quarterly Regulation payments are shown in Figure 2-7 below.

Figure 2-7: Regulation Payments by Quarter, 2013- 2015 ($millions)

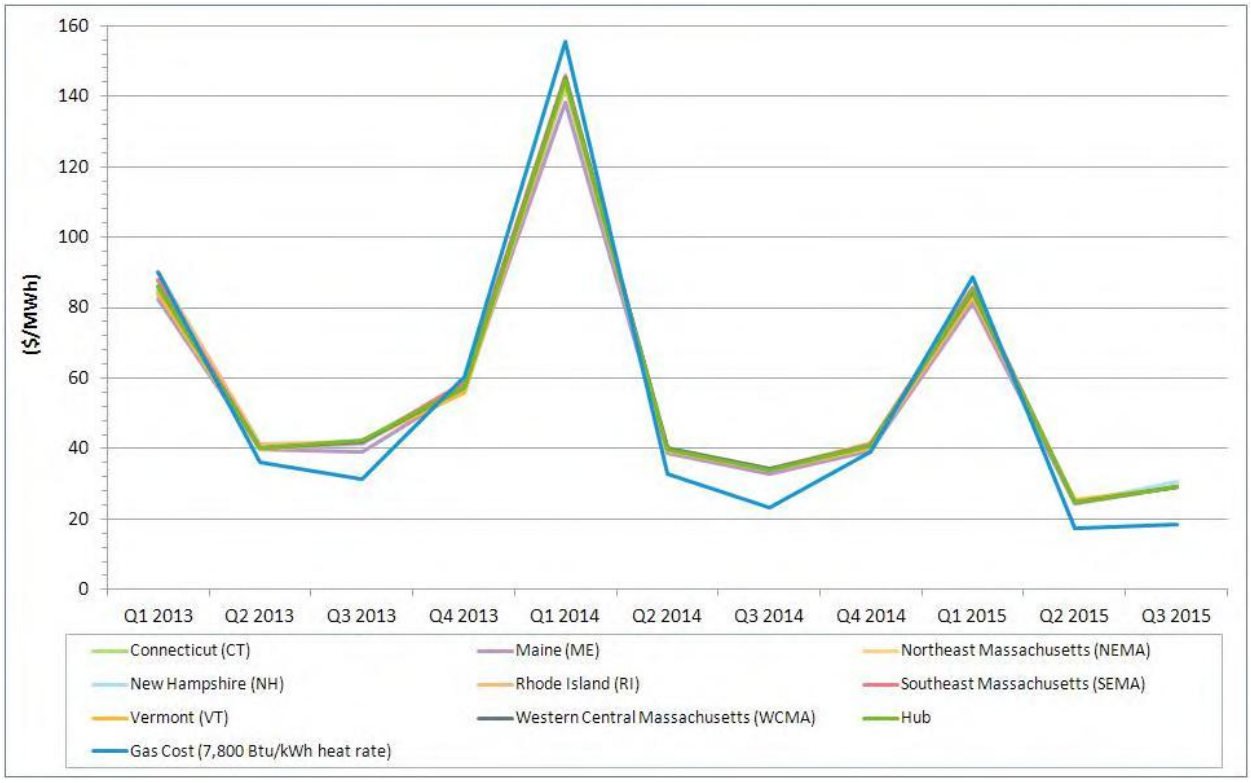


2.1.4 Forward Markets

2.1.4.1 Day-Ahead Energy Market

In the Reporting Period, the average Day-Ahead hub price increased 17% to $29.09/MWh when compared to Q2 2015. The rise in Day-Ahead prices was roughly half of the increase observed in Real-Time prices (Section 2.1.3.1). Prices did not differ significantly among the load zones. Figure 2-8 below depicts quarterly average Day-Ahead energy prices and estimated cost of gas generation (assuming a unit heat rate of 7,800 Btu/kWh and the Algonquin Citygate index price).

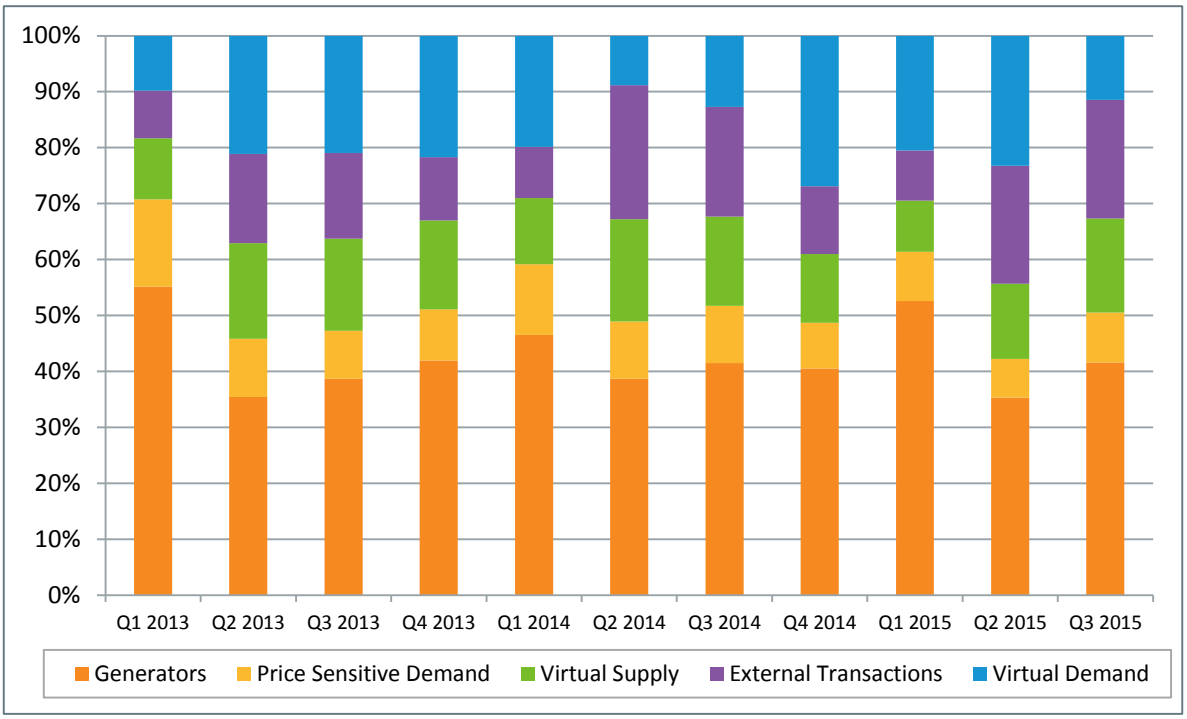
Figure 2-8: Simple Average Day-Ahead Prices and Gas Generation Costs by Quarter, 2013-2015 ($/MWh)



As Figure 2-8 shows, average Day-Ahead energy prices rose in the Reporting Period. The Q3 2015 average hub price was up 17% over Q2 2015, but 14% lower than Q3 2014. As in Real-Time, the Day-Ahead price increased along with natural gas generations costs and demand. However, average Day-Ahead prices were notably lower than Real-Time. The average hub Day-Ahead price of $29.09/MWh was about 10% lower than the hub Real-Time price of $32.15/MWh (Table 2-1). The separation of Real-Time and Day-Ahead prices appears to be due, in part, to the frequency of Real-Time reserve pricing during this quarter (Section 2.1.3.3).

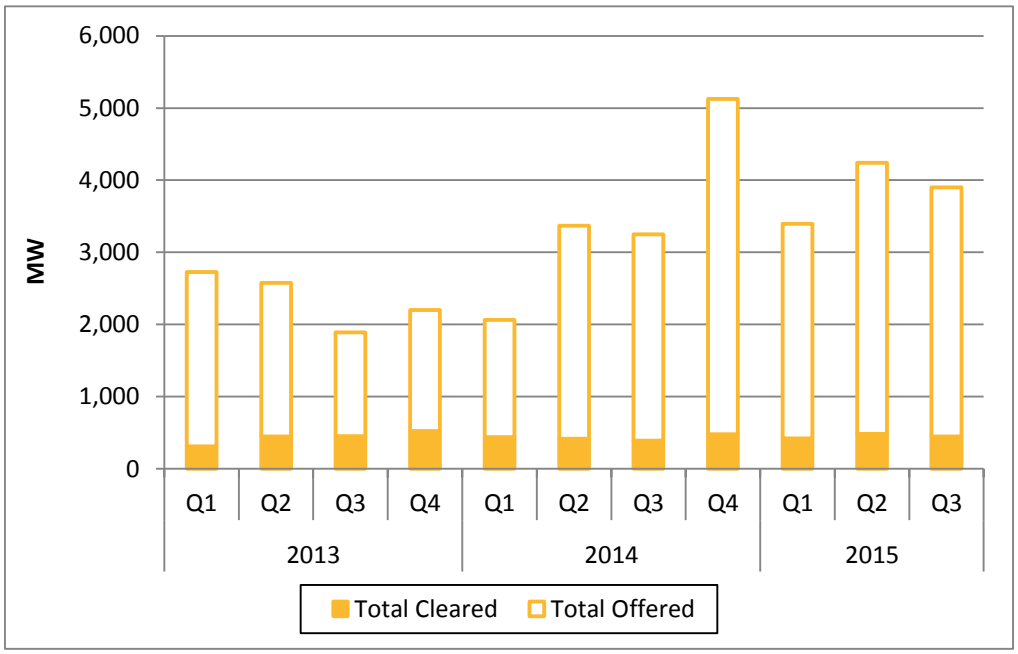
As shown in Figure 2-9, generators set price approximately 42% of the time in the Reporting Period in the Day-Ahead market. Virtual transactions set price approximately 28% of the time, and external transactions set price approximately 21% of the time. This is comparable to Q3 2014, in which generators set price 41% of the time, virtual transactions set price 29% of the time, and external transactions set price 20% of the time in the Day-Ahead market.

Figure 2-9: Day-Ahead Marginal units by type by Quarter, 2013-2015



In the Reporting Period, submitted virtual demand bids and virtual supply offers averaged approximately 3,900 MW per hour, a decrease of 8% when compared with Q2 2015, and an increase of 20% compared with Q3 2014. Cleared virtual transactions decreased by 7% compared with Q2 2015 and increased by 15% when compared with Q3 2014. In the Reporting Period, 11.5% of submitted virtuals bids and offers cleared in the Day-Ahead market. See Figure 2-10.

Figure 2-10: Total Offered and Cleared Virtual Transactions by Quarter, 2013-2015 (average hourly MW)



2.1.4.2 Day-Ahead Supply and Demand Curves

As shown in Figure 2-9 above, a number of different resource types can be marginal in the Day-Ahead market, including physical generation and demand, imports and exports, and virtual generation and demand. At the intersection of the supply and demand curves, the bids or offers of these resources can often be within a narrow range. To illustrate this, we show an approximation of the aggregate supply and demand curves for August 1, 2015 during the peak load hour. This provides insight into the clearing of the Day-Ahead market and the price-setting ability of the various resource types.[9]

The aggregate supply and demand curves in Figure 2-11 approximate the clearing of the Day-Ahead market when no constraints are binding on the system.[10] The aggregate supply curve stacks the offer blocks of each available supply resource bidding into the Day-Ahead market from the lowest price to highest price and accounts for generator economic minimum and maximum operating parameters and resources that offer into the market as must-run. The types of resource offers included are generators, imports, and virtual supply (Incs).

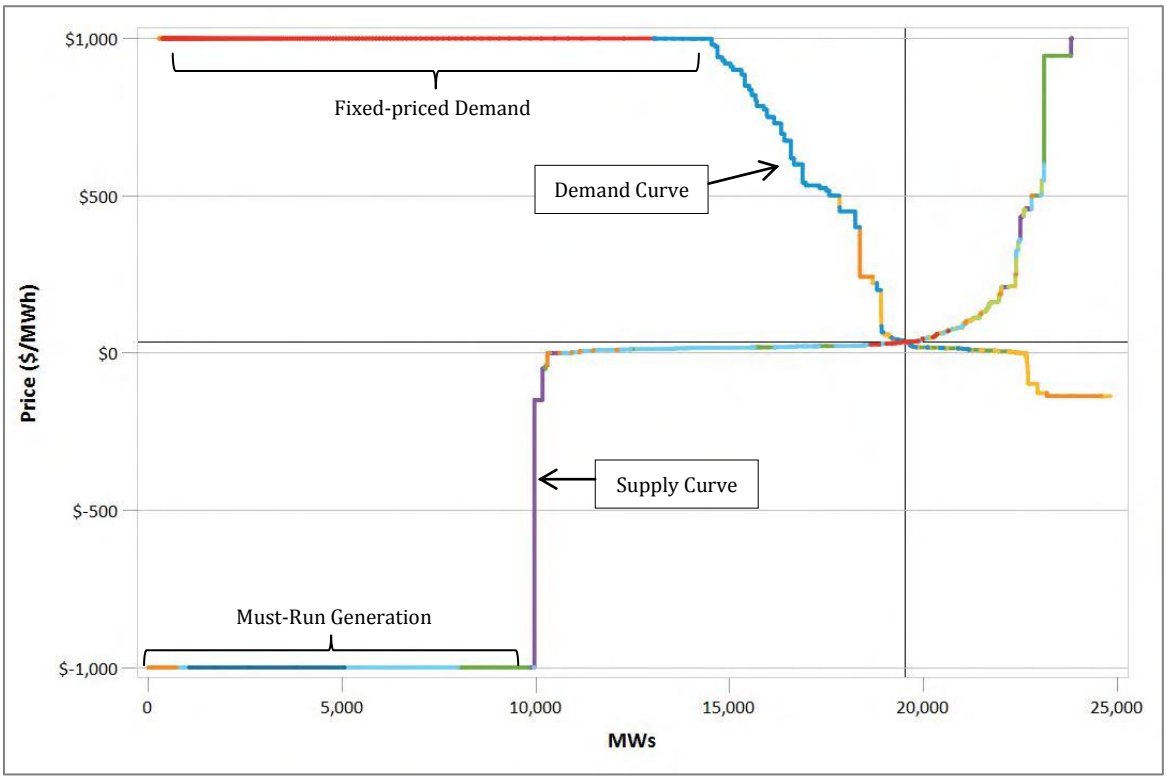
The aggregate demand curve stacks the bid blocks of each demand resource bidding into the Day-Ahead market. The types of resource bids included are fixed demand, price-sensitive demand, exports, virtual demand (Decs), and asset-related demand (ARD).

For the purposes of this example we assume that units offering as must-run or fixed transactions offer in at -$1,000/MWh for supply offers and $1,000/MWh for demand bids. In fact, a resource bidding in the market in this manner will pay or receive the LMP, even if it higher than $1,000 or lower than negative $1,000/MWh.

[9] Hour Ending 17 was the peak load hour for August 1.

[10] In practice the clearing of the Day-Ahead market is much more complex than the use of aggregate supply and demand curves described here. For instance, in this example we do not consider generator operational parameters such as start times and minimum run-times which will impact market clearing,

Figure 2-11: Day-Ahead Market Aggregate Supply and Demand Curves for August 1, 2015, Hour Ending 17[11]



The intersection of the aggregate supply and demand curves represents the approximate market clearing price and quantity.

Many unit types can potentially be marginal within a narrow range. A close-up of the intersection of the two curves is shown in Figure 2-12 below. The approximate clearing price is $35/MWh and the amount of cleared supply is 19,537 MW (at the intersection of the supply and demand curves). This approximation is comparable to the actual Day-Ahead Hub LMP of $32/MWh and amount of cleared supply of 19,610 MW for the time period. The actual marginal unit type was pumped storage as shown where the Day-Ahead Hub LMP of $32/MWh intersects the aggregate supply curve.

[11] For this graph, the legends for supply and demand are:

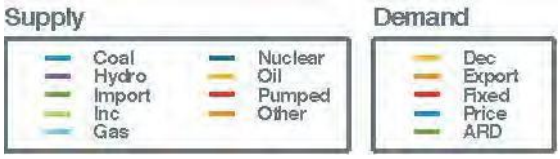
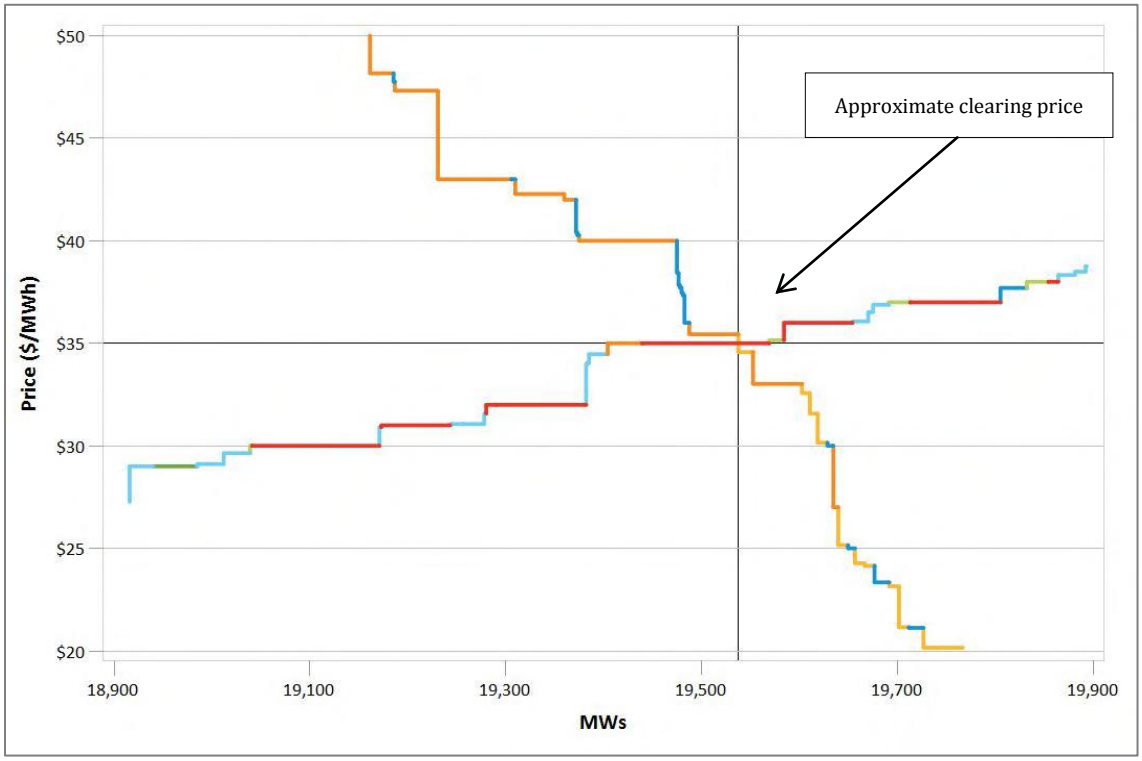


Figure 2-12: Intersection of the Day-Ahead market aggregate supply and demand curves for August 1, 2015, hour ending 17[12]

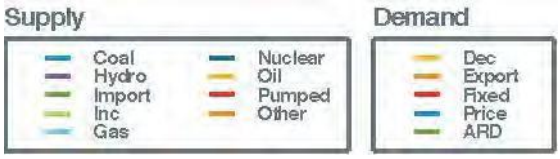


Each segment of the supply and demand curves is colored to represent the type of resource supplying the offer or bid. In the aggregate supply curve, the offers shown are provided by resources burning natural gas, wood (other category), and coal, along with pumped storage, imports and virtual supply. The aggregate demand curve is composed of bids from virtual demand, exports, and price sensitive demand. Pumped storage is the marginal unit type because the price would continue to be set by a pumped storage unit offer block for a small increase or decrease in load. However, the curves highlight the fact that small changes in several unit's offers or bids can impact which unit type is marginal. It is probable that with some small changes in several units' offers, natural gas, wood, coal, virtual supply, virtual demand, exports, or price sensitive demand could have been the marginal unit type with minimal impact on price.

2.1.4.3 Forward Reserve Market

This section presents the results and our analysis of the competitiveness of the Winter 2015-2016 Locational Forward Reserve Market (LFRM) auction. The Winter 2015-2016 auction closed with a clearing price of $5,434/MW-month for all reserve zones and products. Market conditions existed

[12] For this graph, the legends for supply and demand are:



in the Winter 2015-2016 LFRM auction to provide a competitive outcome for all reserve zones and products except for the TMOR product in Southwest Connecticut. We note that there is a general lack of competition and high concentration levels, as measured by the Herfindahl Hirschman Index (HHI) in Southwest Connecticut.

The Forward Reserve bidding period opened at midnight on Tuesday, August 18, 2015 and closed at noon on Monday, August 24, 2015. Forward reserve auction offers were submitted on a portfolio basis by reserve zone. The auction simultaneously clears offers for TMNSR and TMOR to meet the forward reserve requirements for each reserve zone. A Market Participant whose offers cleared in the forward reserve auction received a forward reserve obligation for each reserve zone equal to the amount of that Market Participant's forward reserve auction offers that cleared in the auction.

To meet their forward reserve obligations, Market Participants must assign MW to their forward reserve resources on a daily basis at any time prior to the end of the re-offer period for the operating day such that their aggregate assignments are greater than or equal to their forward reserve obligations.

Requirements. The LFRM auction is designed to provide reserves to meet the reserve requirements of the zones. Some zones are constrained in terms of how much power they can import from other zones. Potentially, as observed in some of the earlier auctions, due to such restrictions, zones can have different clearing prices. As a result, instead of having a single reserve requirement for all of New England, the ISO identifies requirements at a regional level, as well as a systemwide requirement, for each reserve product procured in the auction.

The TMNSR purchase amount represented the expected single contingency of the HQ Phase II Interconnection, which was then increased to reflect a 20% average fleet-wide historical non-performance of resources called upon after a contingency. The TMOR purchase amount represented the expected single contingency of Seabrook. The New England control area forward reserve requirements were based on a 1st contingency of 1,679 MW and a 2nd contingency of 1,249 MW.[13] Local forward reserve requirements (local second contingency and external reserve support MW) for the reserve zones reflect the need for a 30-minute contingency response to provide support in import-constrained areas.[14] See Table 2-2.

[13] The local forward reserve requirements for each applicable reserve zone were based on the 95th percentile value from historical requirements data for the previous two like forward reserve procurement periods for each applicable reserve zone. The forward reserve market requirements for the New England control area are based on the forecast of the first and second contingency supply losses for the next forward reserve procurement period.

[14] The ISO establishes the locational reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each reserve zone for like forward reserve procurement periods (winter to winter and summer to summer). The daily peak hour requirements are aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each Reserve Zone establishes the locational requirement.

Table 2-2: Forward Reserve Requirements for the Winter 2015-2016 LFRM Auction (MW)

Reserve Zone	Reserve Category	Local 2nd Contingency MW	External Reserve Support MW	Reserve Requirement MW
New England Control Area	TMNSR	N/A	N/A	1,270
New England Control Area	TMOR	N/A	N/A	805
SWCT	TMOR	1,096	1,061	36
CT	TMOR	1,233	1,081	152
NEMA/Boston	TMOR	1,386	2,562	0

Forward Reserve Threshold Price Components. Between October 1, 2015, and May 31, 2016, Market Participants that clear in the forward reserve auction for the Winter 2015-2016 forward reserve procurement period must offer corresponding blocks of energy at or above the daily forward reserve threshold price, which is calculated as the product of the Winter 2015-2016 forward reserve heat rate and the daily forward reserve fuel index.

The forward reserve heat rate for the Winter 2015-2016 forward reserve procurement period was 16,876 Btu/kWh, which was based on an analysis of historical implied heat rates. This analysis is based on the Real-Time hub LMP, and the lower of the distillate or natural gas fuel price indices for New England. The period of this analysis is from the start of SMD to the most recent available data. The heat rate used for a specific forward reserve procurement period is the implied heat rate value that occurs at the 97.5th percentile and does not change during a forward reserve procurement period. The daily forward reserve fuel index is the lesser of the natural gas or heating oil price indices as available one day before the operating day.[15]

Results. The clearing price in the LFRM auction for Winter 2015-2016 was $5,434/MW-month for all reserve zones and products. See Table 2-3.

Table 2-3: Auction Clearing Price, Three-Most-Recent FRM Auctions ($/MW-month)

Location	Product	Winter 2014/2015	Summer 2015	Winter 2015/2016
CT	TMOR	8,990	5,834	5,434
NEMA/Boston	TMOR	8,990	14,000	5,434
SWCT	TMOR	8,990	5,834	5,434
Systemwide	TMNSR	8,990	5,834	5,434
Systemwide	TMOR	8,990	5,834	5,434

[15] The price indices are defined as:
Natural gas price index - This price index is the lowest of the Day-Ahead natural gas prices at three key New England hubs: Algonquin Citygates, Iroquois-Zone 2, and Tennessee-Zone 6 on the 200 lateral. For each hub, the price is the volume-weighted average price that is effective for the Operating Day.
Heating oil price index - This price index is the simple average of the *buy* and *sell* prices of the Argus Diesel 15ppm NYH Barge Prompt index as published in the most recently available "Argus US Products" report. The price is then increased by an additional seven percent to account for transportation costs.

The net payments to LFRM resources equals the forward reserve market auction clearing price minus the forward capacity market clearing price. Therefore, as the forward capacity market clearing price for the 2015/2016 capacity commitment period was $3,434/MW-month, the net payments to be received by reserve providers is $2,000/MW-month ($5,434/MW-month less $3,434/MW-month) for the Winter 2015-2016 auction for all reserve zones and products.

Competitiveness. Twenty Market Participants participated in the auction system-wide (all products). Sixteen participants offered in the TMNSR product, and fifteen participants offered in the TMOR product.

- The HHI for all products was 1,421. According to DOJ guidelines, the auction system-wide for the Winter 2015-2016 was unconcentrated.[16]
- The HHI for the TMNSR product was 2,011, and the HHI for the TMOR product was 967. The TMNSR product was moderately concentrated and the TMOR product was unconcentrated.

The requirements for the Connecticut reserve zone can be partially fulfilled by the requirements for Southwest Connecticut. In Connecticut, the total MW offered into the auction was 1,138 MW for all products (TMNSR and TMOR), and the total requirement was 188 MW. Eight Market Participants submitted offers in the Connecticut area auction. The largest supplier had a 41% market share. No supplier was pivotal. The HHI was 2,400 (moderately concentrated according to DOJ guidelines), and 661 MW were effectively offered at zero (*i.e.* the forward reserve offer minus the FCA price).

In Southwest Connecticut, the TMOR requirement was 36 MW. Three participants participated in the auction, with the participant with the highest market share at 59%, and the market share of the two largest suppliers was 95%. The HHI in Southwest Connecticut for TMOR was 4,777, highly concentrated according to DOJ guidelines. The total MW offered into the auction for TMOR was 197.7 MW, so there was adequate supply to meet the requirement for the TMOR product. The auction cleared 183.7 MW economically (below the system clearing price of $5,434/MW-Month), and 168 MW were effectively offered at zero.

In NEMA Boston, the reserve requirement was zero MW. This was because the 95th percentile value from historical requirements data from the past two like forward reserve procurement periods was zero.

We have observed that the FRM auction is not structurally competitive and that auction clearing prices tend to be higher when there is less competition in the auction.[17] Further analysis is required to determine if higher auction clearing prices in auctions with less competition are the result of offer prices that were higher than expected.

2.1.4.4 Financial Transmission Rights

Three Financial Transmission Rights (FTR) auctions were conducted during the Reporting Period for a combined total of 111,797 MW of FTR transactions. The total amount distributed as Auction Revenue Rights (ARRs) was $1.7 million. Twenty-nine bidders in July, thirty bidders in August and

[16] See footnotes 22 and 23 below for a description of the HHI and competitiveness thresholds.

[17] *ISO New England's Internal Market Monitor Second Quarter 2015 Quarterly Markets Report* (October 1, 2015), http://www.iso-ne.com/static-assets/documents/2015/10/qmr_q2_2015_10_1_2015_for_filing.pdf.

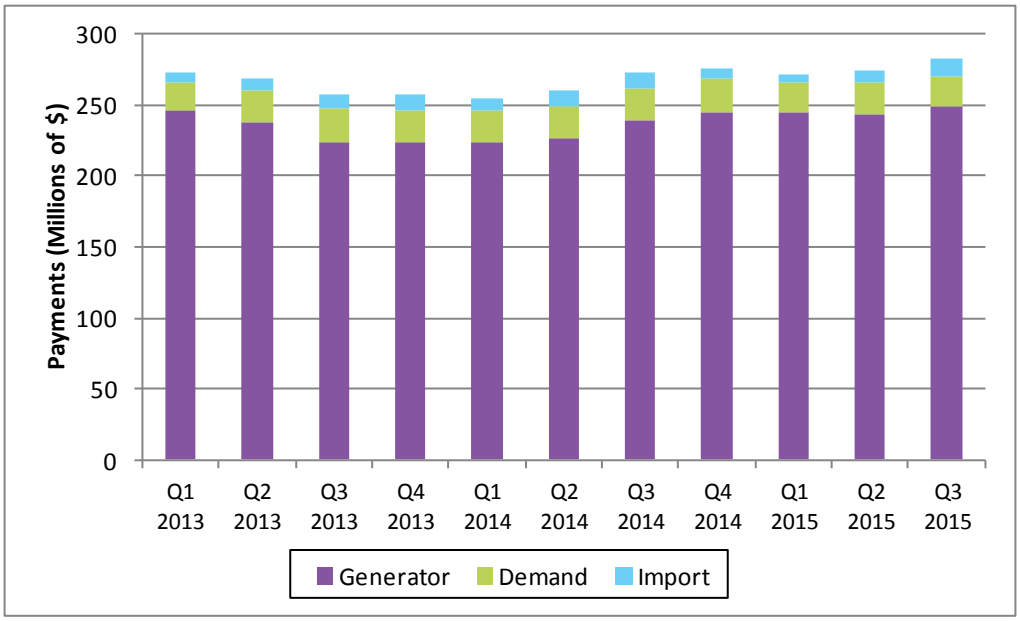
thirty-two bidders in September participated in the monthly auctions for the quarter. The level of participation was consistent with prior auctions.

2.1.4.5 Forward Capacity Market

The Forward Capacity Market (FCM) 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. 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.

Payments. Figure 2-13 shows the total Forward Capacity Market (FCM) payments by resource type from Q1 2013 through the end of the Reporting Period. Capacity payments totaled $282.3 million in the Reporting Period. The forward capacity auction initial supply credit was based on a clearing price of $3.43/kW-month in the Reporting Period. The supply credit paid for capacity supply obligations (CSO) can be adjusted based upon bilateral and reconfiguration auction activity, computed values for Peak Energy Rent (PER), the participation of the ISO in reconfiguration auctions, and actual resource performance, which are accounted for in the data below.

Figure 2-13: Total Capacity Payments by Quarter, 2013-2015 (millions of $)



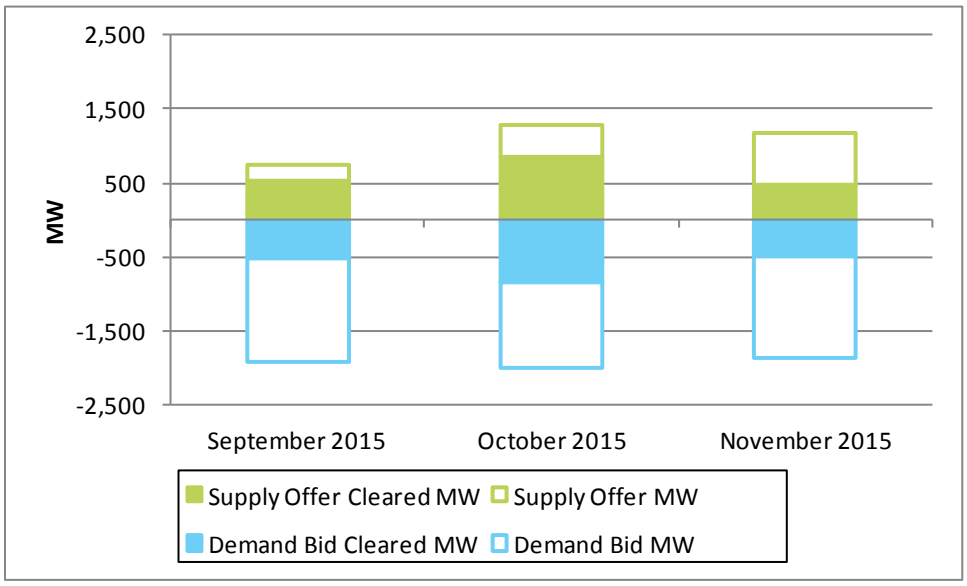
Auctions. Reconfiguration auctions take place before and during the capacity commitment period to allow participants with capacity supply obligations to trade their positions with other resources that do not have CSOs or wish to assume additional CSOs. Annual reconfiguration auctions (ARAs) to acquire one-year commitments are held approximately two years, one year, and just before the capacity commitment period begins. Monthly reconfiguration auctions, held beginning of the first

month of a capacity commitment period, adjust the annual commitments during the commitment period.

Several monthly reconfiguration auctions were conducted and contracts were bilaterally traded during the Reporting Period. Monthly reconfiguration auctions and bilateral trades for the months of September 2015, October 2015, and November 2015 took place during the Reporting Period. There were no annual reconfiguration auctions conducted in the Reporting Period.

Monthly reconfiguration auctions. Figure 2-14 below shows bid/offered and cleared MWs by monthly auction. Supply Offers are offers to sell (or shed) capacity while Demand Bids are bids to buy capacity. The reconfiguration auctions cleared at $3.00, $2.40, and $1.00 per kW-month during each month, with cleared capacity in each auction being 532 MW, 838 MW, and 486 MW for September 2015, October 2015, and November 2015, respectively.

Figure 2-14: Bid/Offered and Cleared MW, September-November 2015 Monthly Reconfiguration Auctions



Bilateral contract periods. Table 2-4 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 110 to 134 MW. Average prices for the bilateral trading periods ranged from $1.99/kW-month to $3.36/kW-month, compared to a clearing price in the primary FCA of $3.43/kW-month.

Table 2-4: Acquired and Transferred MW for the September-November 2015 Bilateral Contract Periods[18]

Month	Resource Type	Acquired MW	Transferred MW	Net MW
September 2015	Demand Response	8	34	(26)
	Generator	103	6	96
	Import	0	70	(70)
September 2015 Total		110	110	0
October 2015	Demand Response	25	52	(27)
	Generator	106	9	97
	Import	0	70	(70)
October 2015 Total		132	132	0
November 2015	Demand Response	28	62	(34)
	Generator	106	2	104
	Import	0	70	(70)
November 2015 Total		134	134	0
Total Q3 2015		**376**	**376**	**0**

2.1.4.6 Demand Response

Demand resource payments totaled $21.3 million in the Reporting Period, which was 4.1% lower than the previous quarter's payments of $22.2 million. Payments equaled $22.9 million in Q3 2014.

The total Capacity Supply Obligation (CSO) for demand resources at the end of the Reporting Period (September) was 2,146 MW, an increase from a year ago when the total CSO equaled 1,921 MW. The increase in the CSO over the year was primarily due to additional resources participating in energy-efficiency programs administered by local utilities.

2.2 System Conditions

2.2.1 Net Commitment Period Compensation

Net Commitment Period Compensation (NCPC) is a method of providing a make-whole payment to resources when market prices are insufficient to cover production costs. Resources committed and dispatched economically (in-merit), as well as resources dispatched out of economic-merit order for reliability purposes, may require make-whole payments. NCPC is paid to resources for providing first- and second-contingency voltage support and control as well as distribution system protection in either the Day-Ahead or Real-Time Energy Markets.[19] Total NCPC payments during the Reporting Period totaled $28.3 million.

Total NCPC payments increased by 5% when compared to last quarter and increased by 32% when compared to Q3 2014. The majority of NCPC incurred during the Reporting Period was for first

[18] The sum of the individual components in this table may not match the subtotal amount due to rounding.

[19] 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).

contingency, or Economic, NCPC. Approximately $20 million of total NCPC was paid in the Real-Time market, with over $13 million in Real-Time Economic NCPC.[20]

The increase in Economic NCPC payments compared to Q3 2014 was largely attributable to several days with suppressed Real-Time prices compared to Day-Ahead prices and to the posturing of limited energy generating resources. Load forecast error appears to have contributed to suppressed Real-Time prices on a number of occasions. Specifically, this can occur when actual load levels are below the forecast, meaning that a surplus of supply is on the system, which in turn tends to put downward pressure on prices.

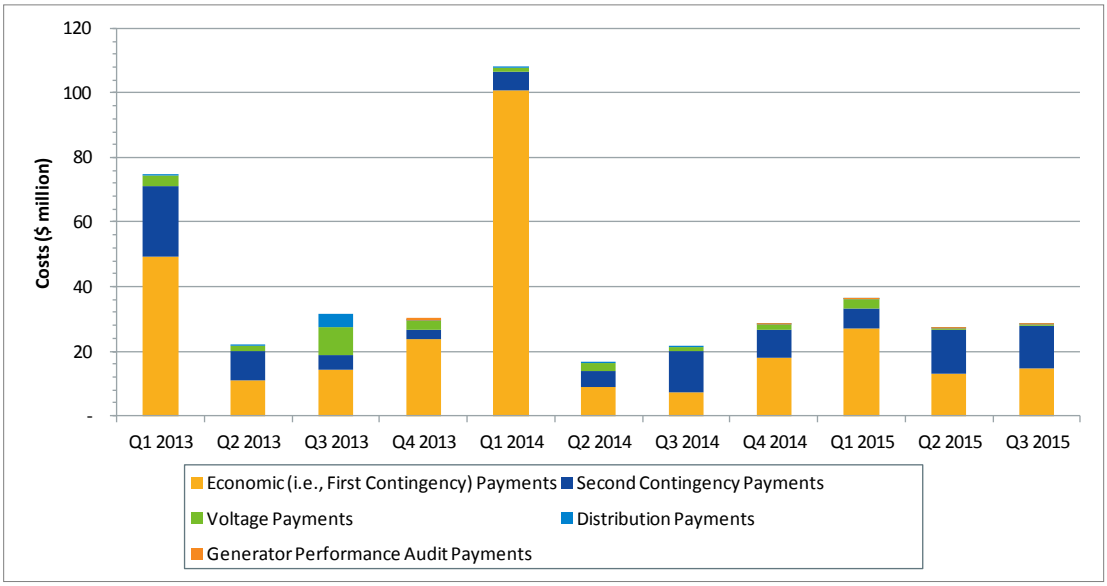
With the increase in Economic NCPC payments we can also see the impact of two elements of the new NCPC rules that went into effect in December 2014 as part of Energy Market Offer Flexibility rules. The first relates to the payment of lost opportunity costs for generators postured to meet system reliability needs. In this case, if a limited energy generator is moved away from its economically optimal output by the ISO, it is made financially whole to that optimal level. Second, under the current NCPC rules a generator scheduled in the Day-Ahead market is eligible for both Day-Ahead and Real-Time NCPC. When combined with lower Real-Time prices compared to prices in the Day-Ahead energy market, this tends to result in higher Real-Time NCPC when the underlying supply offer does not change between the two markets.[21]

[20] *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

[21] ISO New England Inc., joined by the NEPOOL Participants Committee, recently filed tariff revisions to modify two provisions of the NCPC credit rules. The main change is to eliminate payment of NCPC to cover commitment costs in the Real-Time energy market when a non-fast start resource is operating pursuant to a schedule it received in the Day-Ahead energy market. *See ISO New England Inc. and the NEPOOL Participants Committee*, Market Rule 1 Revisions Related to the NCPC Credit Rules, Docket No. ER16-250-000 (filed November 3, 2015). The ISO has requested an effective date of January 15, 2016 for these market rule changes.

Figure 2-15: NCPC Payments by Quarter and Category, 2013-2015 ($ millions)

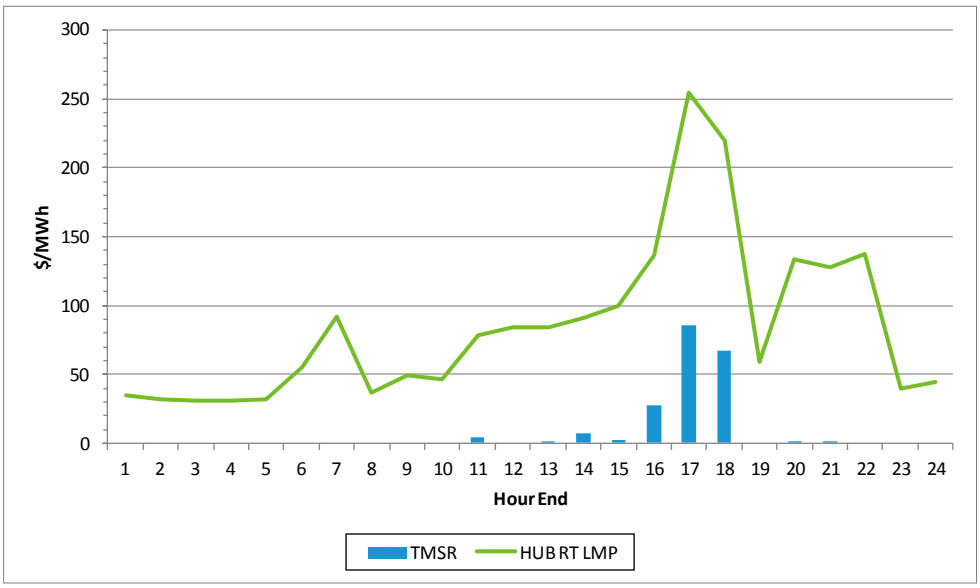


2.2.2 OP4 Event on September 9, 2015

On Wednesday, September 9, 2015, ISO New England implemented Master/Local Control Center Procedure #2 (M/LCC 2), Abnormal Conditions Alert and Operating Procedure #4 (OP#4), Action During a Capacity Deficiency. Going into the day, an operating reserve surplus of 204 MW was projected based on the forecasted load of 23,810 MW. The actual peak load was 24,230 MW for hour ending 17, which was 420 MW above the forecasted value. The increase in load was attributable to higher temperatures and dew points than forecasted during the afternoon hours. The forecasted temperatures in Boston and Hartford during the peak hour were 86 and 88 degrees Fahrenheit, respectively, with actual temps of 90 and 91 degrees Fahrenheit.

At 16:36, a transmission contingency occurred that reduced transfers into New England on Phase 2 by approximately 500 MW creating a slight deficiency in operating reserves. At 16:45, M/LCC 2 and OP #4 Action 1 were declared which allowed New England to begin to deplete thirty minute operating reserves. Action 1 of OP#4 was then cancelled at 18:15 and M/LCC 2 was cancelled at 22:00. The average hourly Hub Real-Time LMP and rest-of-system ten-minute spinning reserve (TMSR) prices on September 9, 2015 are shown in Figure 2-16.

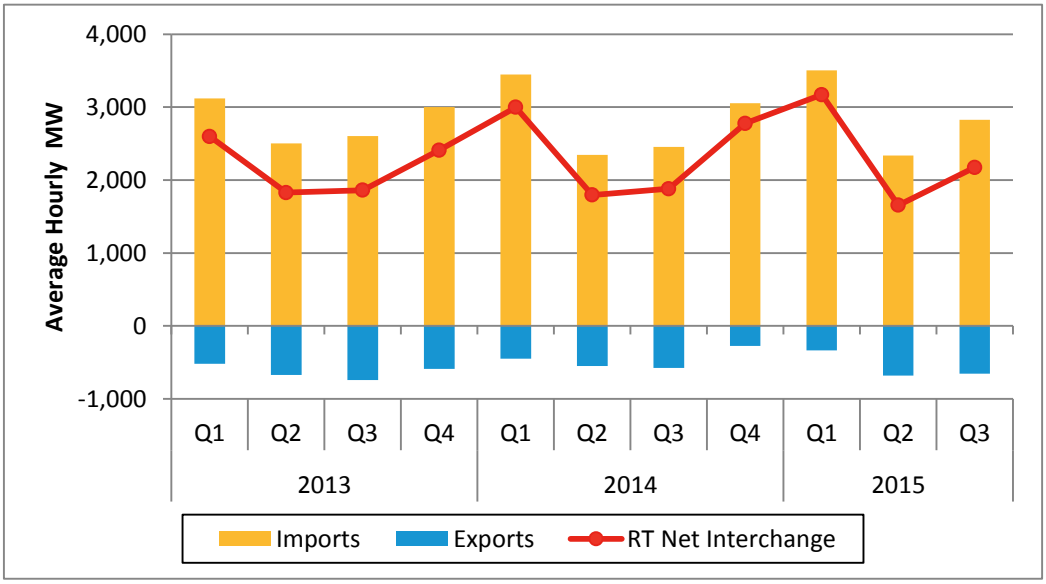
Figure 2-16: September 9, 2015 Real-Time Hub LMPs and TMSR Prices ($/MWh)



2.2.3 Net Interchange

In the Reporting Period, New England was a net importer of power. Net imports from Canada exceeded net imports to New York. Net interchange with neighboring balancing authority areas averaged 2,174 MW per hour for the Reporting Period, a 37% increase compared with Quarter 2 2015 and an 16% increase when compared to Quarter 3 2014. This was primarily due to an increase in imports from the Roseton and Hydro Quebec locations. As shown in Figure 2-17 below, net interchange has been seasonal in nature, with higher imports occurring during the winter months over the past few years. The increase in net imports in Q4 2014 and Q1 2015 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 2-17: Imports, Exports, and Net Interchange by Quarter, 2013-2015 (Average hourly MW)



2.3 Market Competitiveness

The competitiveness of the wholesale electricity market was evaluated by calculating the *Herfindahl-Hirschman Index (*HHI) metric. Based on the results of the HHI metric, we have concluded that the energy market was competitive during the Reporting Period. System-wide concentration remains low. Energy market prices are consistent with costs.

The 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.[22] The HHI accounts for the relative size distribution of 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 as the number of firms in the market decreases and as the disparity in size between those firms increases.[23]

The methodology for calculating the HHI was enhanced for the current Reporting Period to account for affiliations between lead market participants.[24,25] The new methodology accounts for the fact that a number of participants in the New England market are controlled by the same entity, typically referred to as the ultimate parent company. For example, the generation assets registered to two distinct lead market participants with the ISO, but that are in fact controlled by a single company, are now summed and included as one single firm in the HHI calculation.

Conversely, the new methodology also provides for cases in which assets are registered to a single lead participant but controlled by different ultimate parent companies. For example, assets that are controlled by two separate ultimate parent companies, but registered and offered into the market by the same single lead participant, are now allocated to each of the ultimate parent companies, rather than to the lead market participant.

The results of our HHI calculation for the Reporting Period indicate that the wholesale electric energy markets in New England are well within the "not concentrated" range.[26] Figure 2-18

---

[22] 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.

[23] 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.

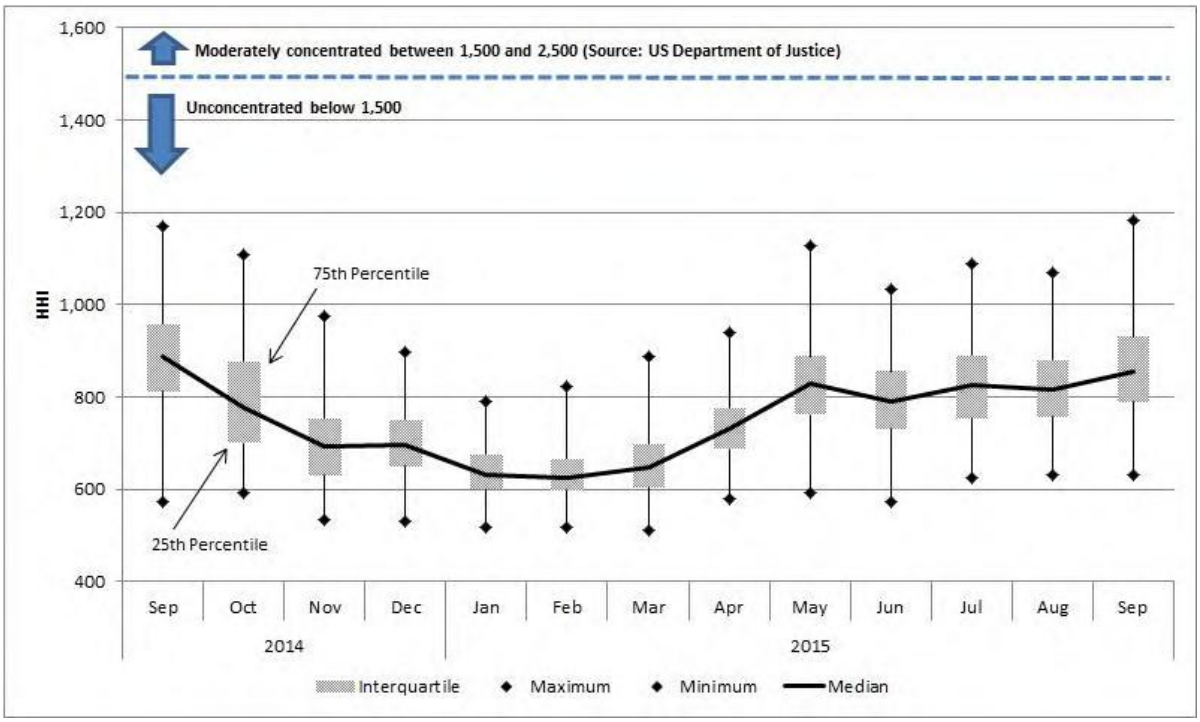
[24] This issue was addressed in *ISO New England's Internal Market Monitor Second Quarter 2015 Quarterly Markets Report* (October 1, 2015), http://www.iso-ne.com/static-assets/documents/2015/10/qmr_q2_2015_10_1_2015_for_filing.pdf. Additional enhancements to the IMM's competitiveness measures, that take account of affiliations, are being developed and will be included in future reports.

[25] The mapping of assets to ultimate parent companies is based on information provided to the ISO by participants. The mapping of assets to ultimate parent company will be periodically updated as new information becomes available.

[26] 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

summarizes the results of our HHI analysis. The box and whisker plot below illustrates statistics for hourly HHI results during peak hours for each month between September 2014 and September 2015.[27] The bottom of the whisker represents the lowest hourly HHI while the top of the whisker represents the highest hourly HHI. The box shows the interquartile range; capturing the range of hourly results from the 25th to 75th percentile. The bottom of the box is the 25th percentile and the top of the box is the 75th percentile of hourly HHI values. The median HHI for each month is represented by the horizontal line within each box. The median HHIs for the past 13 months ranged from 625 in February 2015 to 887 in September 2014.

Figure 2-18: Hourly HHI by Month, September 2014-September 2015



The affiliation data are reflected in the HHI results for July, August and September 2015 (Q3) only. Based on our data and analysis, accounting for affiliations between participants increases HHI modestly by between 20 to 35 points, or 3 to 4%. Essentially, the revised methodology shows a greater concentration in Real-time energy market generation among fewer companies. This is because there are a number of ultimate parent companies with multiple registered lead participants in the New England market. Using the DOJ's *Horizontal Merger Guidelines*, the Real-Time Energy Market in New England continues to be unconcentrated because all hourly HHI observations are below 1,500.

of overall concentration even if these effects produced a net increase in concentration, the impact would likely not change our assessment.

[27] For the purposes of our HHI calculation peak hours are assumed to be from hour ending (HE) 8 through HE 23, 7 days per week.

ISO New England's Internal Market Monitor

Fall 2015

Quarterly Markets Report

Internal Market Monitor
January 29, 2016

Contents

Preface ..... **v**

Section 1 Executive Summary **7**

1.1 Summary of Market Outcomes and Performance *7*

Section 2 Summary of Market Outcomes and System Conditions **9**

2.1 Market Outcomes *9*

2.2 System Conditions *22*

2.3 Market Competitiveness *25*

Tables

Table 2-1: Key Statistics on Load, LMPs, and Natural Gas 10

Table 2-2: Acquired and Transferred MW for the November 2015-January 2016 Bilateral Contract Periods..... 22

Figures

Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Season, 2013-2015 ($ billions and $/MMBtu) 9

Figure 2-2: Simple Average Real-Time Prices and Gas Generation Costs by Quarter, 2013-2015 ($/MWh) 11

Figure 2-3: Real-Time Marginal Units by Fuel Type by Season, 2013-2015 12

Figure 2-4: Average Hourly Demand, 2013-2015 (MW) 13

Figure 2-5: Load Duration Curves, Fall 2013-2015 (MW) 13

Figure 2-6: Real-Time Reserve Payments by Season, 2013- 2015 ($ millions) 15

Figure 2-7: Regulation Payments by Season, 2013- 2015 ($millions) 16

Figure 2-8: Simple Average Day-Ahead Prices and Gas Generation Costs by Quarter, 2013-2015 ($/MWh) 17

Figure 2-9: Day-Ahead Marginal units by Fuel Type by Season, 2013-2015 18

Figure 2-10: Total Offered and Cleared Virtual Transactions by Season, 2013-2015 (average hourly MW) 19

Figure 2-11: Total Capacity Payments by Season, 2013-2015 (millions of $) 20

Figure 2-12: Bid/Offered and Cleared MW, November 2015-January 2016 Monthly Reconfiguration Auctions 21

Figure 2-13: NCPC Payments by Season and Category, 2013-2015 ($ millions) 23

Figure 2-14: Imports, Exports, and Net Interchange by Season, 2013-2015 (Average hourly MW) 25

Figure 2-15: Hourly HHI by Season, Winter 2013-Fall 2015 27

Preface

The Internal Market Monitor ("IMM") of ISO New England Inc. (the "ISO") publishes a Quarterly Markets Report that assesses the state of competition in the wholesale electricity markets operated by the ISO. 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, Appendix A, Section III.A.17.2.2, *Market Monitoring, Reporting, and Market Power Mitigation*:

> The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A.***

This report covers the period from September 1, 2015 to November 30, 2015 (the "Reporting Period"). The report contains our analyses and summaries of market performance. All information and data presented here are the most recent as of the time of publication. Some data presented in this report are still open to resettlement.[1]

Underlying natural gas data furnished by:

[1] Capitalized terms not defined herein have the meanings ascribed to them in Section I of the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the "Tariff").

Oil prices are provided by Argus Media.[2]

[2] *Available at* http://www.theice.com.

Section 1
Executive Summary

This report presents metrics and analysis of the performance of ISO New England wholesale electricity and related markets for the Fall of 2015 (September through November).[3]

1.1 Summary of Market Outcomes and Performance

- The total estimated wholesale market costs were $1.40 billion in the Reporting Period, a 11% decrease compared to the same period in 2014 (Fall 2014).
    - Lower natural gas prices were the primary driver for the decrease in total energy costs. Natural gas prices averaged $3.29/MMBtu. This is a 19% decrease from Fall 2014.
- In Fall 2015, the average hourly demand was 13,545 MW, compared to 13,675 MW in the same season of 2014. The peak Real-Time Load, which occurred on September 8, 2015 during the Reporting Period, was 24,308 MW, 3% higher than the peak load observed in Fall 2014.
- Day-Ahead Energy Market prices averaged $32.47/MWh at the Hub and Real-Time prices averaged $31.53/MWh. Day-Ahead prices were 14% lower than Fall 2014, and Real-Time prices were 15% lower, driven by lower natural gas prices.
- Total Real-Time reserve payments were $11.4 million, a $3.3 million increase from Fall 2014, and Regulation payments totaled $5.6 million, a $4.4 million increase. The increase in total Real-Time reserve payments compared to Fall 2014 was primarily the result of higher average ten-minute spinning reserve (TMSR) prices and an increase in the pricing frequency of non-zero thirty-minute operating reserve (TMOR) prices (from 0.76% to 1.14%). The increase in regulation payments represents a continuation of increased payments under the unbundled regulation service and capacity pricing implemented in March 2015 to comply with FERC Order 755.[4]
- Net Commitment Period Compensation (NCPC) payments totaled $40.2 million, a 89% increase from Fall 2014. The increase in Real-Time first contingency NCPC payments was largely attributable to several days with lower Real-Time prices compared to Day-Ahead prices. Load forecast error appears to have contributed to the lower Real-Time prices on a number of these days. The increase in Real-Time second contingency NCPC payments was largely due to payments in the Northeast Massachusetts load zone to units being committed for second contingency resource protection.

[3] In previous Quarterly Markets Reports, market outcomes were covered by calendar quarter. With this and future quarterly reports, outcomes will be reviewed by season as follows: Winter (December through February), Spring (March through May), Summer (June through August) and Fall (September through November).

[4] Further analysis of the regulation market will be provided in a future report as more experience is gained with the new market rules.

- Overall, the energy market was competitive. The system-wide concentration of supply ownership remains low. Energy market prices are consistent with input costs.

Section 2
Summary of Market Outcomes and System Conditions

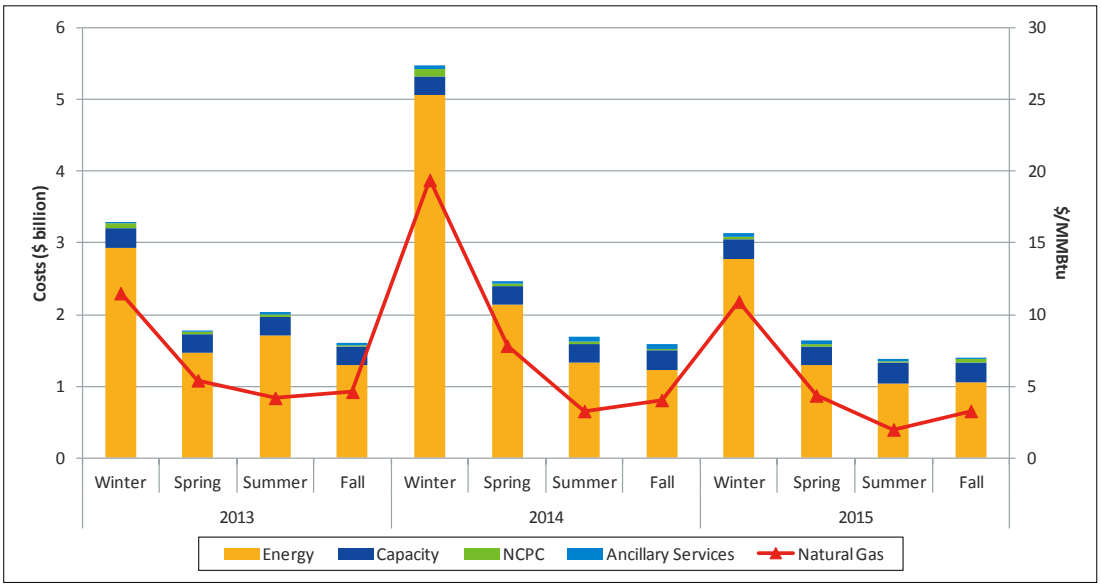
This section summarizes the region's wholesale electricity market outcomes and measures of market performance and competitiveness in the Reporting Period (September 1, 2015-November 30, 2015).

2.1 Market Outcomes

2.1.1 Total Wholesale Electricity Market Value

In Fall 2015, the total estimated market cost decreased by about 11% compared to the same season last year ($1.40 billion compared to $1.58 billion in September 1, 2014 - November 30, 2014), and increased by 2% when compared to Summer 2015 ($1.38 billion for June 1, 2015-August 31, 2015).[5] Net Commitment Period Compensation (NCPC) costs in Fall 2015, at $40 million, increased by 101% compared to Summer 2015 and increased by 89% compared to Fall 2014. Ancillary service costs, which include reserve and regulation payments, totaled $26 million in Fall 2015, a decrease of 15% when compared to Summer 2015 and a decrease of 57% when compared to Fall 2014, respectively. Figure 2-1 below shows the estimated wholesale electricity cost for each season (in billions of dollars) by market, along with average natural gas prices (in $/MMBtu).

Figure 2-1: Wholesale Market Costs and Average Natural Gas Prices by Season, 2013-2015 ($ billions and $/MMBtu)



As shown in Figure 2-1, natural gas prices were a key driver behind changes in energy costs. The increase in natural gas prices, coupled with a decrease in demand, resulted in a slight increase in

[5] The total cost of electric energy is approximated as the product of the Day-Ahead load obligation for the region and the average Day-Ahead locational marginal price (LMP) plus the product of the Real-Time load deviation for the region and the average Real-Time LMP. Transmission network costs as specified in the Open Access Transmission Tariff (OATT) are not included in the estimate of quarterly wholesale costs.

energy costs in Fall 2015 compared to Summer 2015. Compared to Fall 2014, gas prices were lower in Fall 2015, resulting in lower energy costs.

2.1.2 Key Market Statistics

Table 2-1 shows selected key statistics for load levels, Real-Time and Day-Ahead Energy Market prices, and fuel prices.

Table 2-1: Key Statistics on Load, LMPs, and Natural Gas

	Fall 2015	Summer 2015	Percent Change Fall 2015 to Summer 2015	Fall 2014	Percent Change Fall 2015 to Fall 2014
Real-Time Load (GWh)	29,583	34,459	-14%	29,914	-1%
Weather Normalized Real-Time Load (GWh)	29,317	34,509	-15%	29,550	-1%
Peak Real-Time Load (MW)	24,308	24,437	-1%	23,715	3%
Average Day-Ahead Hub LMP ($/MWh)	32.47	25.94	25%	37.94	-14%
Average Real-Time Hub LMP ($/MWh)	31.53	26.86	17%	37.11	-15%
Average Natural Gas Price ($/MMBtu)	3.29	2.00	64%	4.04	-19%

The following factors contributed to market outcomes in the Reporting Period when compared to the corresponding season of last year:

- Lower natural gas prices in Fall 2015 were the primary driver for lower Day-Ahead and Real-Time prices when compared to the same season last year.
    - Natural gas prices during the Reporting Period decreased by 19% from Fall 2014.
    - Oil prices were also 42% lower during the Reporting Period compared to Fall 2014.
- The Real-Time Load in Fall 2015 was 1% lower than the Real-Time load in Fall 2014.
- The peak Real-Time Load, which occurred on September 8, 2015 during the Reporting Period, was 24,308 MW, 3% higher than the peak load observed in Fall 2014.

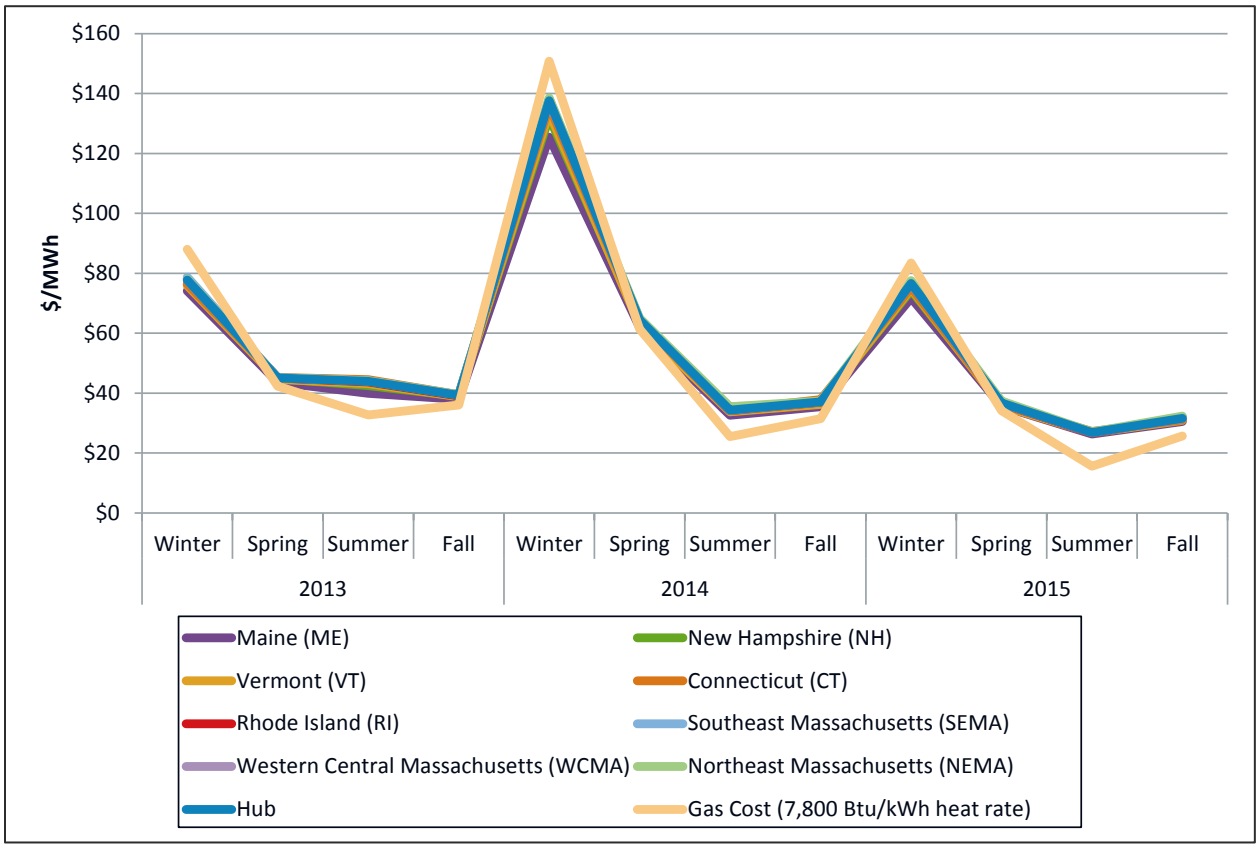
2.1.3 Real-Time Markets

2.1.3.1 Real-Time Energy Market

The average Real-Time hub price was $31.53/MWh in the Reporting Period, a 18% increase over the $26.86/MWh average for Summer 2015. Real-Time prices stayed correlated with the cost of natural gas which also increased over the prior quarter (see Table 2-1). Prices did not differ significantly among the load zones.[6] Figure 2-2 below shows the seasonal quarterly average Real-Time energy prices and the estimated cost of gas generation (assuming a unit heat rate of 7,800 Btu/kWh and the Algonquin Citygate index price).

[6] A *load zone* is an aggregation of pricing nodes within a specific area; there are currently eight load zones in the New England region that correspond to the reliability regions.

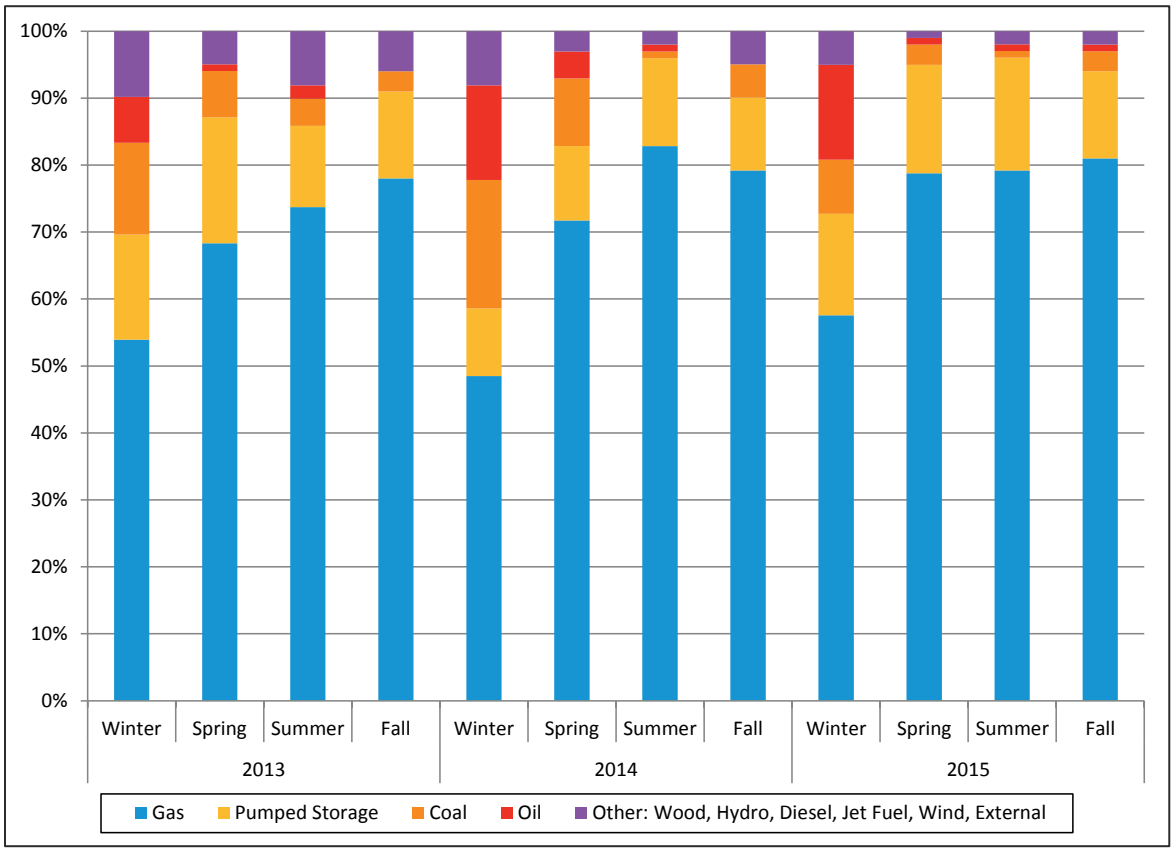
Figure 2-2: Simple Average Real-Time Prices and Gas Generation Costs by Quarter, 2013-2015 ($/MWh)



As Figure 2-2 shows, average Real-Time energy prices rose in the Reporting Period compared to the previous quarter. The average hub price was up 17% over Summer 2015, but 15% lower than Fall 2014. Energy prices continued to track the cost of natural gas-fired generation, which also was up this quarter, as shown by the movement in the zonal energy price trend lines and the yellow gas cost trend line.

In the Reporting Period, units burning natural gas were marginal (*i.e.*, setting the price) for 81% of the pricing intervals, followed by pump storage units (including pumping demand) which were marginal for 13% of the pricing intervals. Units burning coal, oil, diesel, jet fuel, wood, traditional hydro units, and external transactions were marginal in the remaining pricing intervals. Figure 2-3 below shows the percentages of marginal fuels since Winter 2013 (starting December 2012).

Figure 2-3: Real-Time Marginal Units by Fuel Type by Season, 2013-2015

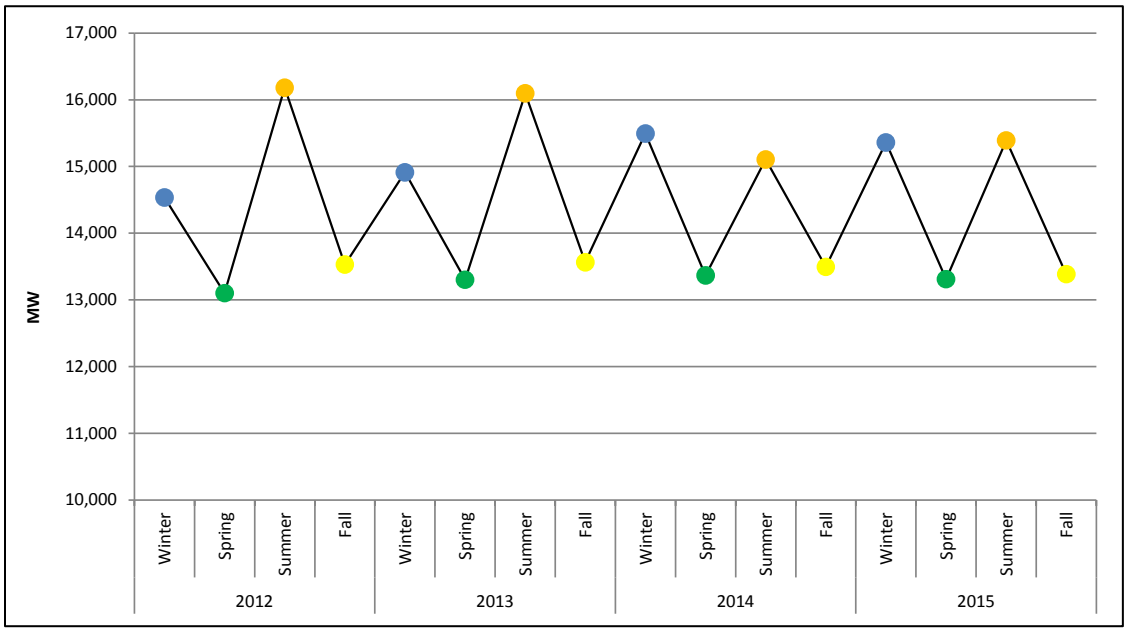


2.1.3.2 Load Summary

In the Reporting Period, the average hourly load was comparable to prior Fall seasons (within about 1%) as shown in Figure 2-4. In Fall 2015, the average hourly load was 13,545 MW, compared to 13,675 MW in Fall 2014.[7]

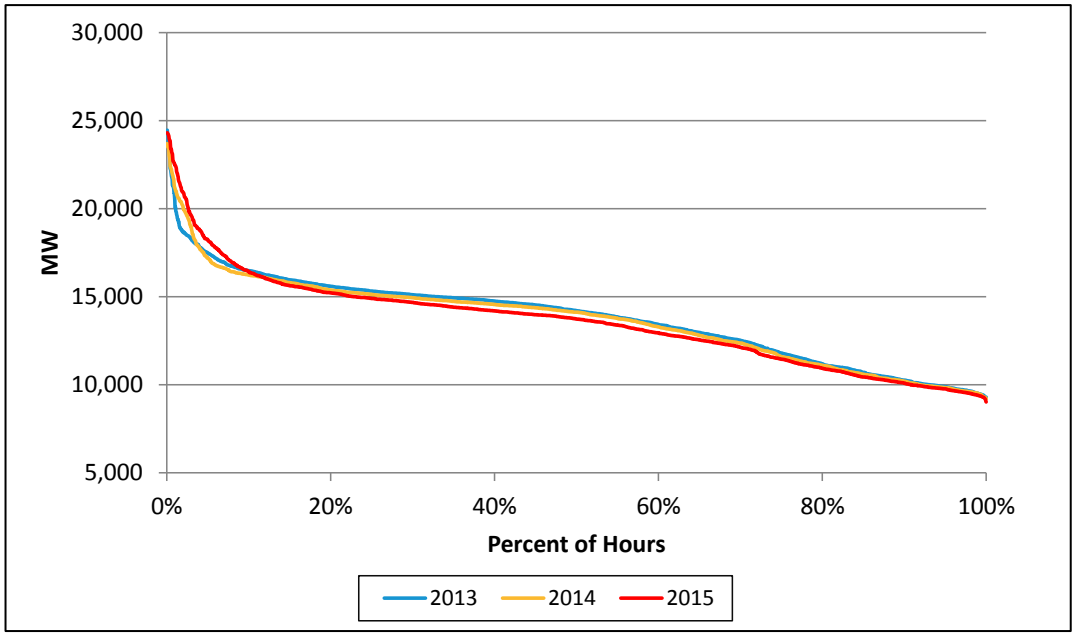
[7] The terms "demand" and "load" are used interchangeably and are intended to have the same meaning in this report.

Figure 2-4: Average Hourly Demand, 2013-2015 (MW)



Another way to examine load is to take all hourly loads in the season (i.e. 2,184 hourly values in the Reporting Period) and sort them from highest to lowest. The resulting curve is called a *load duration curve.* By plotting several load duration curves by year, one can easily observe differences between years for a time period of interest. Also, since the load duration curves have the same number of observations (hours), the horizontal axis can be expressed in percent of the total time period of interest as shown in Figure 2-5. The percent axis allows one to quickly view what percent of hours are above or below a particular load level.

Figure 2-5: Load Duration Curves, Fall 2013-2015 (MW)



The peak hourly demand in the Reporting Period occurred on September 8 at 4:00 PM and was 24,308 MW, similar in magnitude to the Fall 2014 peak of 23,696 MW. The Fall 2014 peak load also occurred in September. In the Reporting Period, approximately 3 percent of the hourly demand exceeded 20,000 MW. Total energy sales were 29,583 GWh in the Reporting Period, a decrease of 0.9% compared to Fall 2014's sales of 29,866 GWh. The decrease in energy sales can also be attributed to warmer weather in the Reporting Period relative to Fall 2014. The average temperature for Fall of 2015 was 55.6 degrees, compared with Fall 2014, which was 53.5 degrees.

The lowest hourly demand in the Reporting Period occurred on September 27 at 4:00 AM and was 9,019 MW.

2.1.3.3 Real-Time Operating Reserves

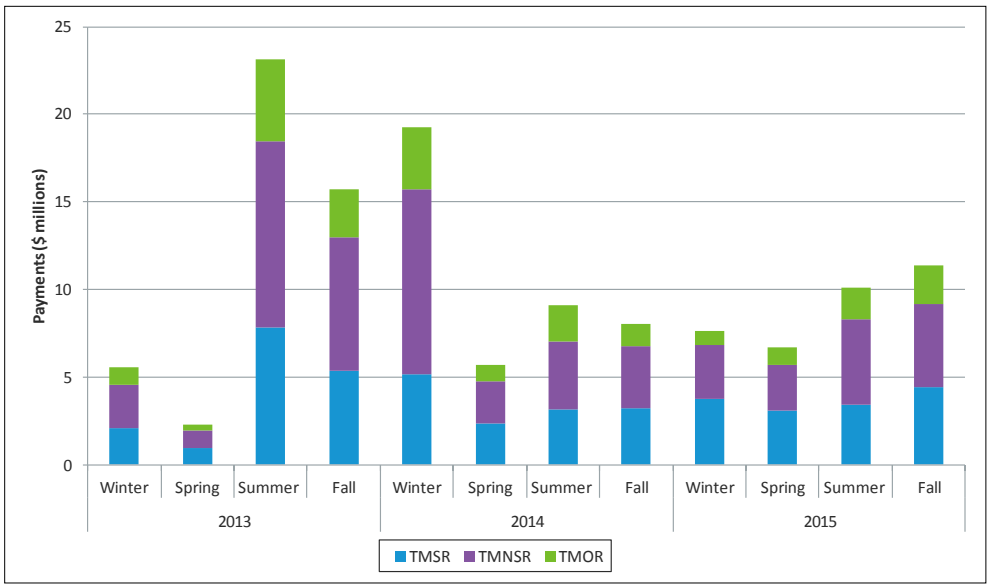
Total Real-Time reserve payments were $11.4 million; a $3.3 million increase relative to Fall 2014's $8.0 million of payments.[8] The increase in total payments compared to Fall 2014 was primarily the result of higher average ten-minute spinning reserve (TMSR) prices and an increase in the pricing frequency of non-zero thirty-minute operating reserve (TMOR) prices (from 0.76% to 1.14%).[9] Real-Time reserve payments also increased from Summer 2015 to Fall 2015 by $1.3 million due to the same reasons.

Higher average reserve pricing represents increased opportunity costs for generators that have their energy dispatch reduced in order to maintain unloaded capacity in the form of operating reserves to meet reserve requirements. Higher than average temperatures during the first month of the season resulted in several days with loads over the forecast and tight system conditions, which contributed to the increase in TMOR reserve pricing frequency. Figure 2-6 shows the total Real-Time reserve payments by season.

[8] Payment data represent total payments for Real-Time reserves, and are not net of settlement adjustments for forward reserve obligation charges.

[9] Note that increased Reserve Constraint Penalty Factors (implemented at the beginning of Winter 2015) might also explain a small portion of the increase in payments, when comparing Fall 2014 to Fall 2015.

Figure 2-6: Real-Time Reserve Payments by Season, 2013- 2015 ($ millions)



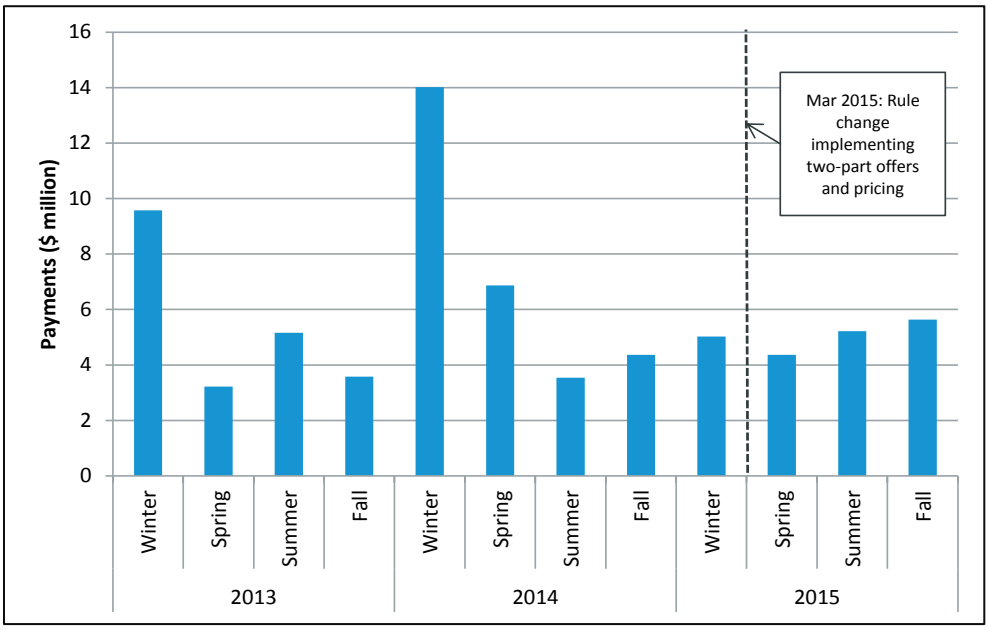
As shown in Figure 2-6, operating reserve payments vary significantly over time. This is the result of a variety of factors including system conditions, fuel prices, Real-Time LMP variation, and changes to operating reserve requirement and pricing rules.

2.1.3.4 Regulation Market

Total Regulation Market payments were $5.6 million during the Reporting Period, up 8% from $5.2 million in Summer 2015, and up 29% from $4.4 million in Fall 2014. The latter result represents a continuation of increased regulation payments under the unbundled regulation service and capacity pricing implemented in March 2015 to comply with FERC Order 755.[10] Quarterly Regulation payments are shown in Figure 2-7 below.

[10] FERC Order 755 led to two sets of changes in regulation compensation since 2013. In Summer 2013, opportunity costs associated with providing regulation were included in the market clearing price for regulation; previously, those costs were paid on an as-bid, resource-specific basis, and were not included in the regulation market clearing pricing. To ensure that resources providing regulation were compensated for all incurred regulation costs, a make-whole (or uplift) payment also was implemented for resources having as-bid costs that exceeded regulation service and capacity payments. Secondly, on March 31, 2015, ISO New England implemented additional regulation market changes, unbundling the pricing for regulation service and capacity and eliminating the regulation self-schedule concept. The changes were a result of FERC Order 755 requiring two-part bidding and compensation of frequency regulation resources to be based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service. The rule changes included the introduction of a two-part methodology for offer and clearing prices. Resources now submit both a regulation capacity ($/MW) and service ($/MW-mile) offer prices. The ISO's least cost optimization produces a corresponding clearing price for capacity, which includes the opportunity costs of the marginal unit, and a clearing price for service.

Figure 2-7: Regulation Payments by Season, 2013- 2015 ($millions)

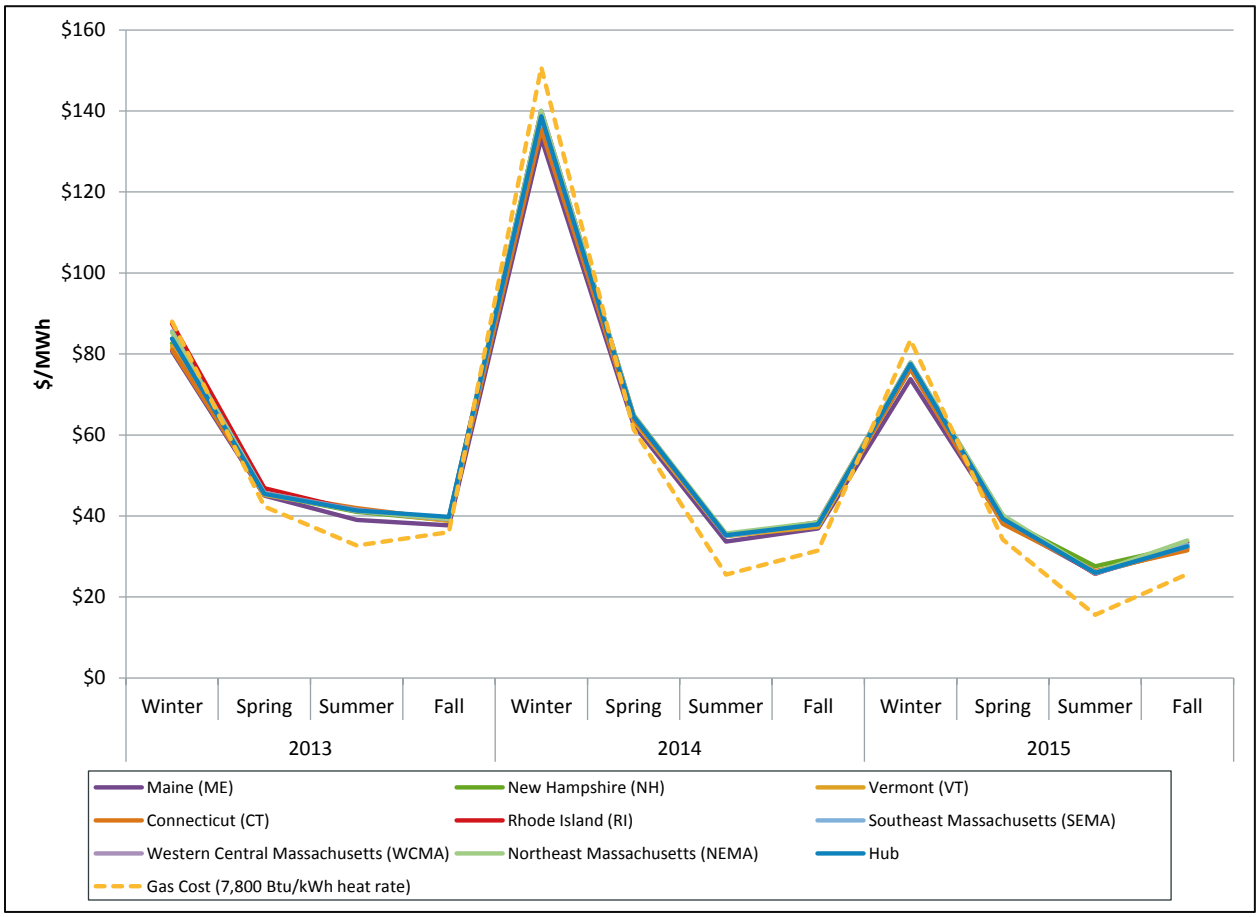


2.1.4 Forward Markets

2.1.4.1 Day-Ahead Energy Market

In the Reporting Period, the average Day-Ahead hub price increased 25% to $32.47/MWh when compared to Summer 2015. The average Day-Ahead hub price was roughly 3% higher than the average Real-Time hub price of $31.53/MWh (Section 2.1.3.1). Prices did not differ significantly among the load zones. Figure 2-8 below depicts seasonal quarterly average Day-Ahead energy prices and estimated cost of gas generation (assuming a unit heat rate of 7,800 Btu/kWh and the Algonquin Citygate index price).

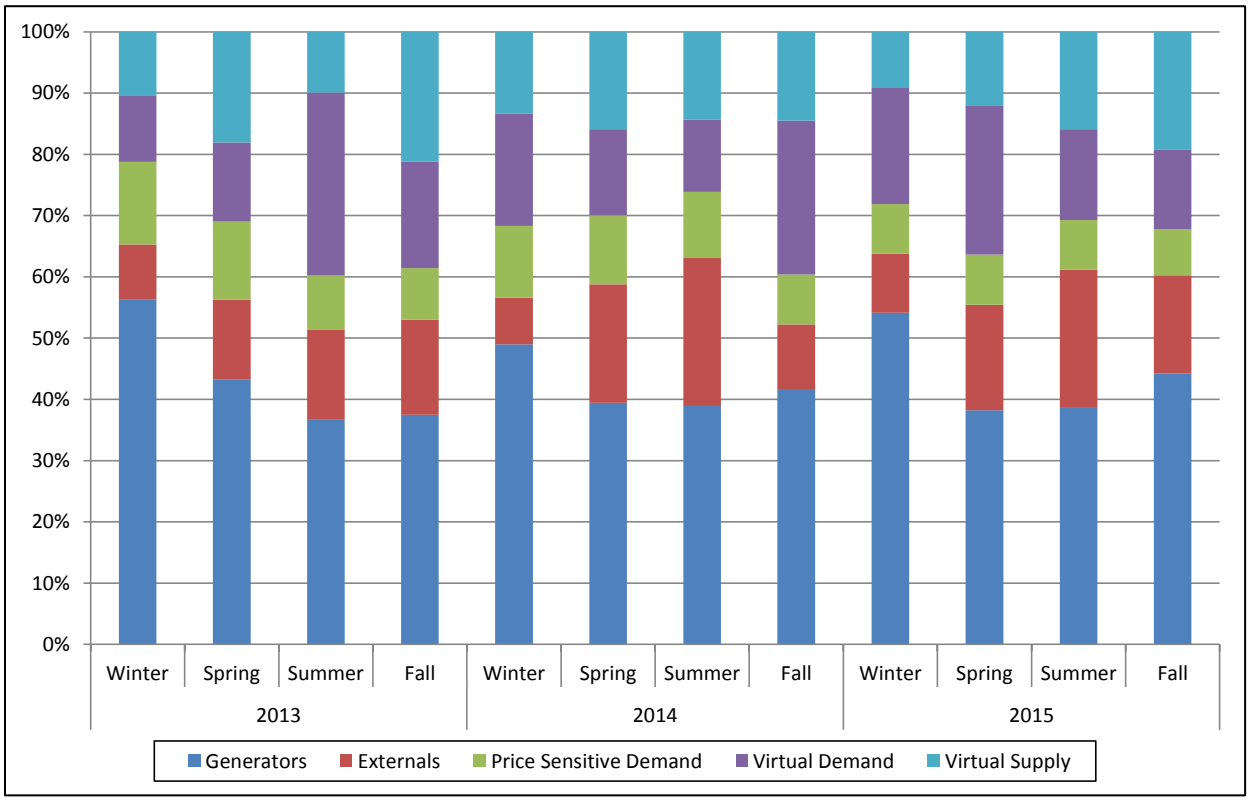
Figure 2-8: Simple Average Day-Ahead Prices and Gas Generation Costs by Quarter, 2013-2015 ($/MWh)



As Figure 2-8 shows, average Day-Ahead energy prices rose along with natural gas generations costs in the Reporting Period. The Fall 2015 average hub price was up 25% over Summer 2015, but 14% lower than Fall 2014.

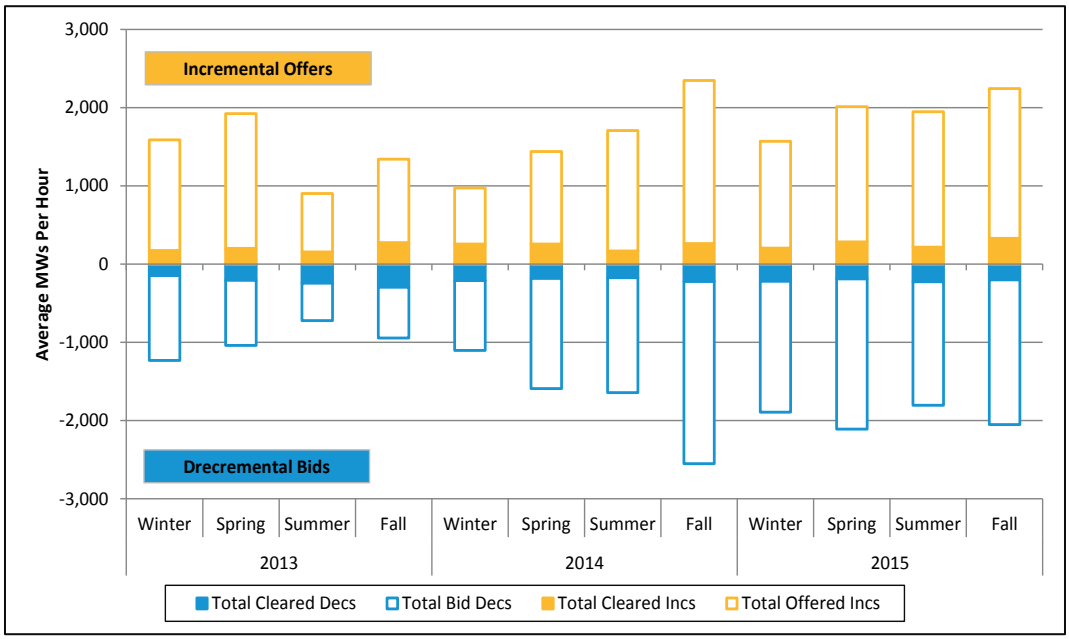
As shown inFigure 2-9, generators set price approximately 44% of the time in the Reporting Period in the Day-Ahead market. Virtual transactions (virtual supply and demand) set price approximately 32% of the time, and external transactions set price approximately 16% of the time. Price-sensitive demand makes up the remainder of price-setting resource at 8%. Figure 2-9 below shows the percentages of marginal fuels since Winter 2013.

Figure 2-9: Day-Ahead Marginal Units by Fuel Type by Season, 2013-2015



In the Reporting Period, submitted virtual demand bids and virtual supply offers averaged approximately 4,300 MW per hour, an increase of 14% when compared with Summer 2015, and a decrease of 12% compared with Fall 2014. Cleared virtual transactions increased by 20% compared with Summer 2015 and increased by 9% when compared with Fall 2014. In the Reporting Period, 12.4% of the megawatt quantity of virtuals bids and offers cleared in the Day-Ahead market. See Figure 2-10.

Figure 2-10: Total Offered and Cleared Virtual Transactions by Season, 2013-2015 (average hourly MW)



2.1.4.2 Financial Transmission Rights

Three Financial Transmission Rights (FTR) auctions were conducted during the Reporting Period for a combined total of 89,990 MW of FTR transactions. The total amount distributed as Auction Revenue Rights (ARRs) was $1.9 million. Thirty-two bidders in September, thirty-three bidders in October and thirty-two bidders in November participated in the monthly auctions for the quarter. The level of participation was consistent with prior auctions.

2.1.4.3 Forward Capacity Market

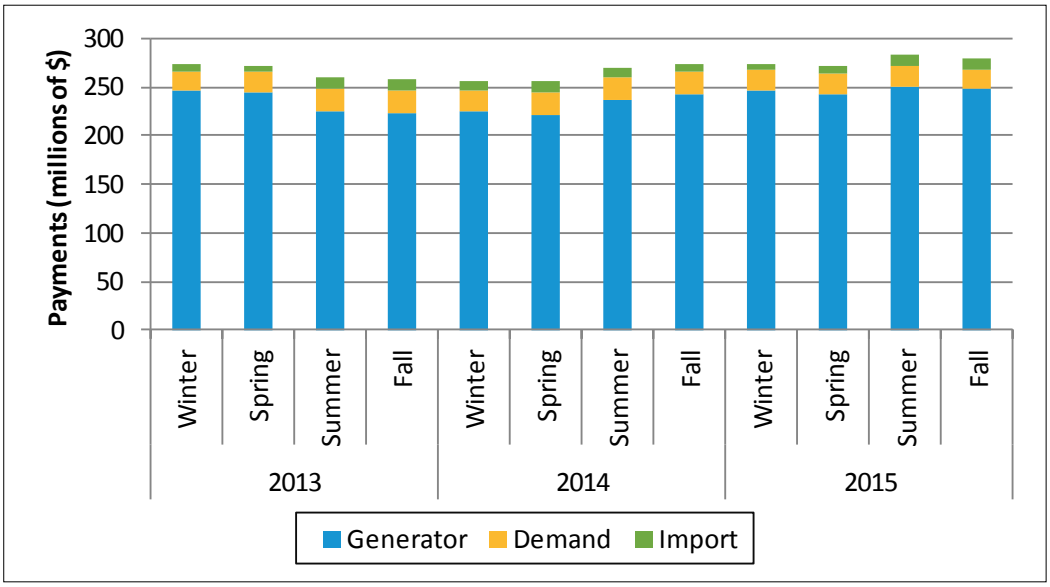
The Forward Capacity Market (FCM) is a long-term market designed to procure the resources needed to meet the region's local and systemwide resource adequacy requirements. The FCM is designed to procure and price capacity before the system will need it. The region developed the FCM in recognition of the 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.

Payments. Figure 2-11 shows the total Forward Capacity Market (FCM) payments by resource type from Winter 2013 through the end of the Reporting Period. Capacity payments totaled $280 million in the Reporting Period. The forward capacity auction initial supply credit was based on a clearing price of $3.43/kW-month in the Reporting Period.[11] The supply credit paid for capacity supply obligations (CSO) can be adjusted based upon bilateral and reconfiguration auction activity,

[11] The clearing price for the 2015/16 capacity commitment period (FCA 6) was set by an administrative floor price.

computed values for Peak Energy Rent (PER), the participation of the ISO in reconfiguration auctions, and actual resource performance, which are accounted for in the data below.

Figure 2-11: Total Capacity Payments by Season, 2013-2015 (millions of $)

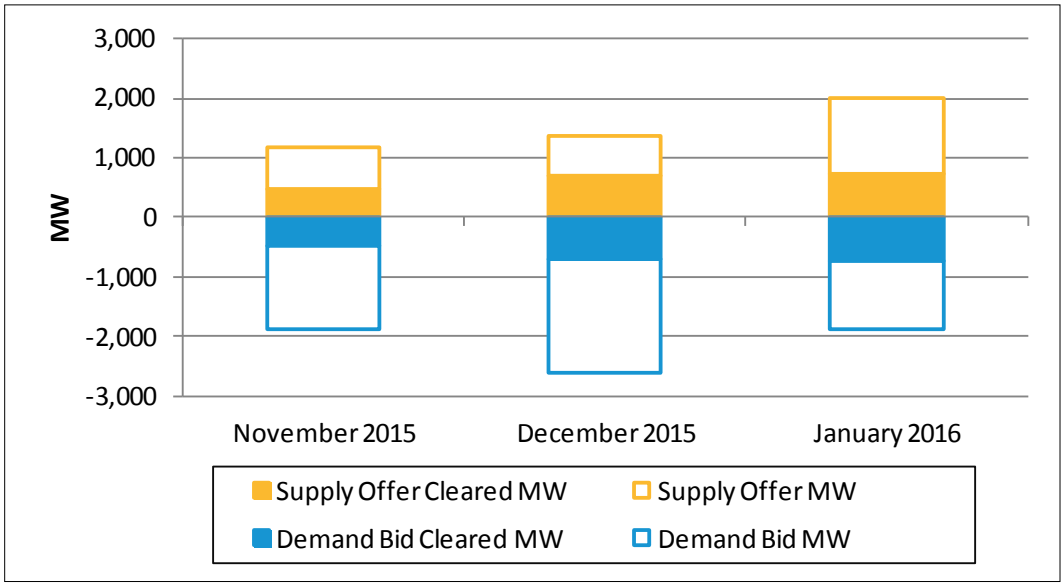


Auctions. Reconfiguration auctions take place before and during the capacity commitment period to allow participants with capacity supply obligations to trade their positions with other resources that do not have CSOs or wish to assume additional CSOs. Annual reconfiguration auctions (ARAs) to acquire one-year commitments are held approximately two years, one year, and just before the capacity commitment period begins. Monthly reconfiguration auctions, held beginning with the first month of a capacity commitment period, adjust the annual commitments during the commitment period.

Several monthly reconfiguration auctions were conducted and contracts were bilaterally traded during the Reporting Period. Monthly reconfiguration auctions and bilateral trades for the months of November 2015, December 2015, and January 2016 took place during the Reporting Period. There were no annual reconfiguration auctions conducted in the Reporting Period.

Monthly reconfiguration auctions. Figure 2-12 below shows bid/offered and cleared MWs by monthly auction. Supply Offers are offers to sell (or shed) capacity while Demand Bids are bids to buy capacity. The reconfiguration auctions cleared significantly below the annual price from the primary auction at $1.00, $1.00, and $0.99 per kW-month during each month, with cleared capacity in each auction being 486 MW, 698 MW, and 727 MW for November 2015, December 2015, and January 2016, respectively.

Figure 2-12: Bid/Offered and Cleared MW, November 2015-January 2016 Monthly Reconfiguration Auctions



Bilateral contract periods. Table 2-2 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 110 to 157 MW. Average prices for the bilateral trading periods ranged from $1.63/kW-month to $3.25/kW-month, compared to a clearing price in the primary FCA of $3.43/kW-month.

Table 2-2: Acquired and Transferred MW for the November 2015-January 2016 Bilateral Contract Periods[12]

Month	Resource Type	Acquired MW	Transferred MW	Net MW
November 2015	Demand Response	28	62	(34)
	Generator	106	2	104
	Import	0	70	(70)
November 2015 Total		**134**	**134**	**0**
December 2015	Demand Response	20	57	(37)
	Generator	137	31	107
	Import	0	70	(70)
December 2015 Total		**157**	**157**	**0**
January 2016	Demand Response	12	39	(27)
	Generator	98	1	97
	Import	0	70	(70)
January 2016 Total		**110**	**110**	**0**
Total Fall 2015		**400**	**400**	**0**

Demand Response. Demand resource payments totaled $21.1 million in the Reporting Period, which was 1% lower than the previous season's payments of $21.3 million. Payments equaled $23.4 million in Fall 2014.

The total Capacity Supply Obligation (CSO) for demand resources at the end of the Reporting Period (November) was 2,132 MW, an increase from a year ago when the total CSO equaled 1,861 MW. The increase in the CSO over the year was primarily due to additional resources participating in energy-efficiency programs administered by local utilities.

2.2 System Conditions

2.2.1 Net Commitment Period Compensation

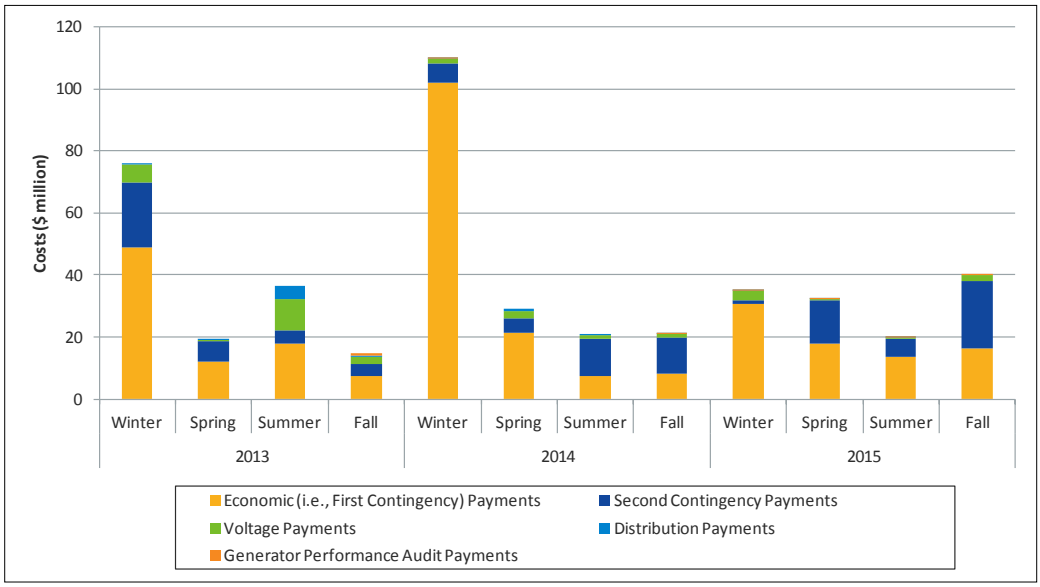
Net Commitment Period Compensation (NCPC) is a method of providing a make-whole payment to resources when market payments are insufficient to cover production costs. Resources committed and dispatched economically (in-merit), as well as resources dispatched out of economic-merit order for reliability purposes, may require make-whole payments. NCPC is paid to resources for providing first- and second-contingency protection, voltage support and control, and distribution system protection in either the Day-Ahead or Real-Time Energy Markets.[13] Total NCPC payments during the Reporting Period totaled $40.2 million.

[12] The sum of the individual components in this table may not match the subtotal amount due to rounding.

[13] NCPC payments include *economic/first contingency NCPC 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).

Total NCPC payments during the reporting period increased by 101% when compared to Summer 2015 and increased by 89% when compared to Fall 2014. As shown in Figure 2-13, the majority of NCPC incurred during the Reporting Period was for first and second contingency which accounted for the increase in total NCPC payments compared to Fall 2014. Of the approximately $25.4 million of total NCPC paid in the Real-Time market, $13.1 million was paid in Real-Time first contingency NCPC[14] and $10.9 million was paid in Real-Time second contingency NCPC. Of the approximately $14.8 million of total NCPC paid in the Day-Ahead market, $3.5 million was paid in Day-Ahead first contingency NCPC and $10.7 million was paid in Day-Ahead second contingency NCPC.

Figure 2-13: NCPC Payments by Season and Category, 2013-2015 ($ millions)



The increase in Real-Time first contingency NCPC payments compared to Fall 2014 was largely attributable to several days with lower Real-Time prices compared to Day-Ahead prices. Load forecast error appears to have contributed to the lower Real-Time prices on a number of these days. Specifically, this can occur when actual load levels are below the forecast, which can lead to a surplus of supply capacity on the system, which in turn tends to put downward pressure on prices. The increase in Real-Time second contingency NCPC payments compared to Fall 2014 was largely due to payments in the Northeast Massachusetts load zone to units being committed for second contingency resource protection.

[14] *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 load hours.
- Reliability costs incurred for generation committed for daily peak load hours but are still on-line after the daily peak load hours to satisfy minimum run-time requirements.

With the increase in Real-Time first and second contingency NCPC payments we can see the impact of one element of the new NCPC rules that went into effect in December 2014 as part of Energy Market Offer Flexibility (EMOF) rules. Under the current NCPC rules, a generator scheduled in the Day-Ahead energy market is eligible for both Day-Ahead and Real-Time NCPC. When Real-Time energy prices are lower than Day-Ahead energy prices, this tends to result in higher Real-Time NCPC when the underlying supply offers do not change between the two markets. For units that are committed for local second contingency protection in the Day-Ahead market, they are now eligible for second contingency NCPC payments in both the Day-Ahead and Real-Time markets. Because of this rule, the amount of second contingency NCPC paid to these units in the Real-Time market tends to be very similar to the amount of second contingency NCPC paid to them in the Day-Ahead market if their underlying supply offer does not change between the two markets.[15]

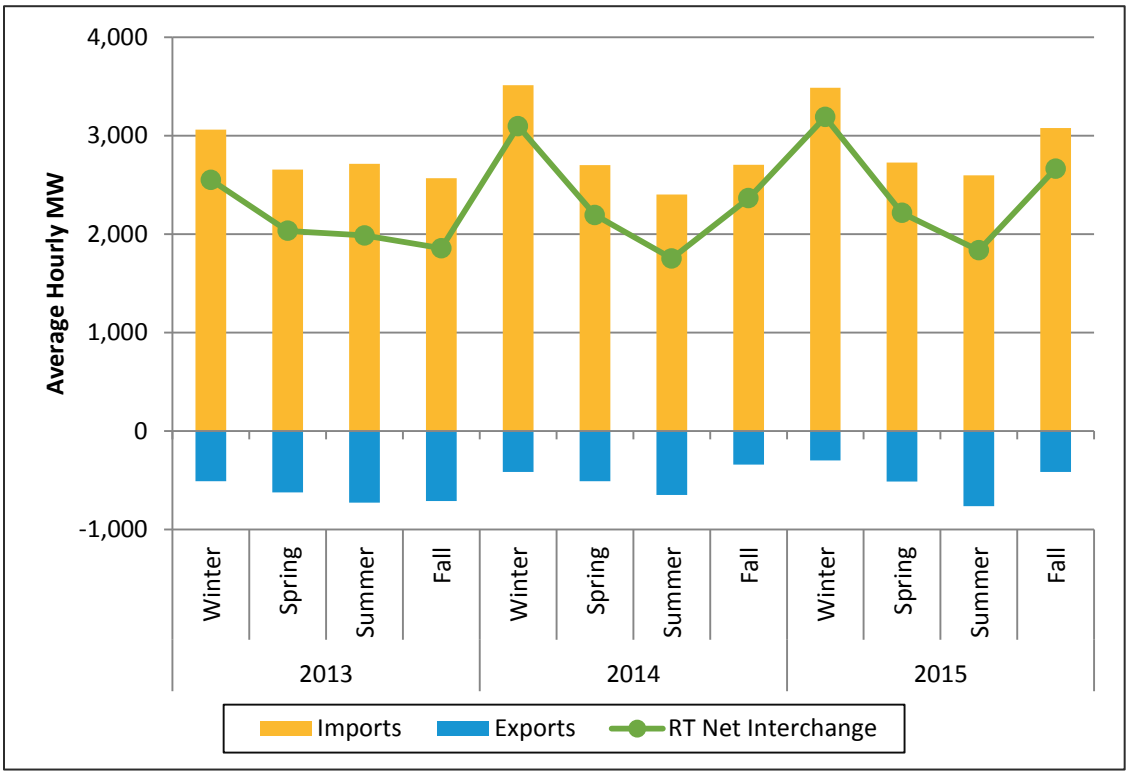
2.2.2 Net Interchange

In the Reporting Period, New England was a net importer of power. Net imports from Canada exceeded net imports from New York.[16] Net interchange with neighboring balancing authority areas averaged 2,663 MW per hour for the Reporting Period, a 45% increase compared with Summer 2015 and an 13% increase when compared to Fall 2014. This was primarily due to an increase in imports from the Roseton and New Brunswick locations. As shown in Figure 2-14 below, net interchange has been seasonal in nature, with higher imports occurring during the winter months over the past few years. The increase in net imports in Fall 2014 and Winter 2015 was partially due to the loss unplanned loss of the Cross Sound cable, which was the result of a transformer fire in New Haven. The Cross Sound cable is predominantly a net exporter of power to New York.

[15] In December 2015 the Federal Energy Regulatory Commission accepted revisions to the ISO New England Inc. market rules to modify two provisions of the NCPC credit rules. *ISO New England Inc. and the NEPOOL Participants Committee*, Letter Order Accepting Net Commitment Period Compensation Credit Rules, Docket No. ER16-250-000 (issued December 23, 2015). The main change eliminates payment of NCPC to cover commitment costs in the Real-Time energy market when a non-fast start resource is operating pursuant to a schedule it received in the Day-Ahead energy market.

[16] New England has transmission connections with Canada and New York; Quebec (via the HQ Phase II and HQ Highgate interfaces), New Brunswick and New York (via the New York-North, Northport-Norwalk and the Cross Sound Cable interfaces). The Canadian interfaces total approximately 2,600 MW (New England/New Brunswick: 1,000 MW, Highgate HVDC: 200 MW, and Phase II HVDC: 1,400 MW) in import capability. Under normal circumstances, the Canadian interfaces import power into New England. The New York Interfaces are as follows: The New York-North interface has a net import capability of 1,400 MW and a net export capability of approximately 1,200 MW. This interface can import power to, or export power from New England. Northport-Norwalk has a capability of approximately 200 MW and is generally a net exporter of power to New York. The Cross Sound Cable is a DC Converter with a capability of approximately 330 MW and power is generally exported to New York.

Figure 2-14: Imports, Exports, and Net Interchange by Season, 2013-2015 (Average hourly MW)



2.3 Market Competitiveness

The structural competitiveness of the wholesale electricity market was evaluated by calculating the Herfindahl-Hirschman Index (HHI) metric. System-wide concentration remains low. Generally, in lower concentrated markets, participants are less likely to have the ability to exercise market power. However, this is not to say that market power does not exist during certain system conditions. In such cases, a suite of mitigation rules are in place and are triggered automatically to mitigate the effect of market power on outcomes in the Day-Ahead and Real-Time energy market.

The 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.[17] The HHI accounts for the relative size distribution of 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

[17] 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.

10,000 points when a market is controlled by a single firm. The HHI increases as the number of firms in the market decreases and as the disparity in size between those firms increases.[18]

The methodology for calculating the HHI was enhanced in the previous Reporting Period to account for affiliations between lead market participants.[19,20] The improved methodology produces an HHI that better reflects the concentration of control in the market. The change is reflected in the HHI results beginning in Summer 2015 and will be used moving forward.

The results of our HHI calculation for the Reporting Period indicate that the wholesale electric energy markets in New England are well within the "not concentrated" range.[21] Figure 2-15 summarizes the results of our HHI analysis. The box and whisker plot below illustrates statistics for hourly HHI results for each season between Winter 2013 and Fall 2015. The bottom of the whisker represents the lowest hourly HHI while the top of the whisker represents the highest hourly HHI. The box shows the interquartile range; capturing the range of hourly results from the 25th to 75th percentile. The bottom of the box is the 25th percentile and the top of the box is the 75th percentile of hourly HHI values. The median HHI for each season is represented by the horizontal line within each box. The median HHIs for the past 12 seasons ranged from 633 in Winter 2014 to 850 in Fall 2013.

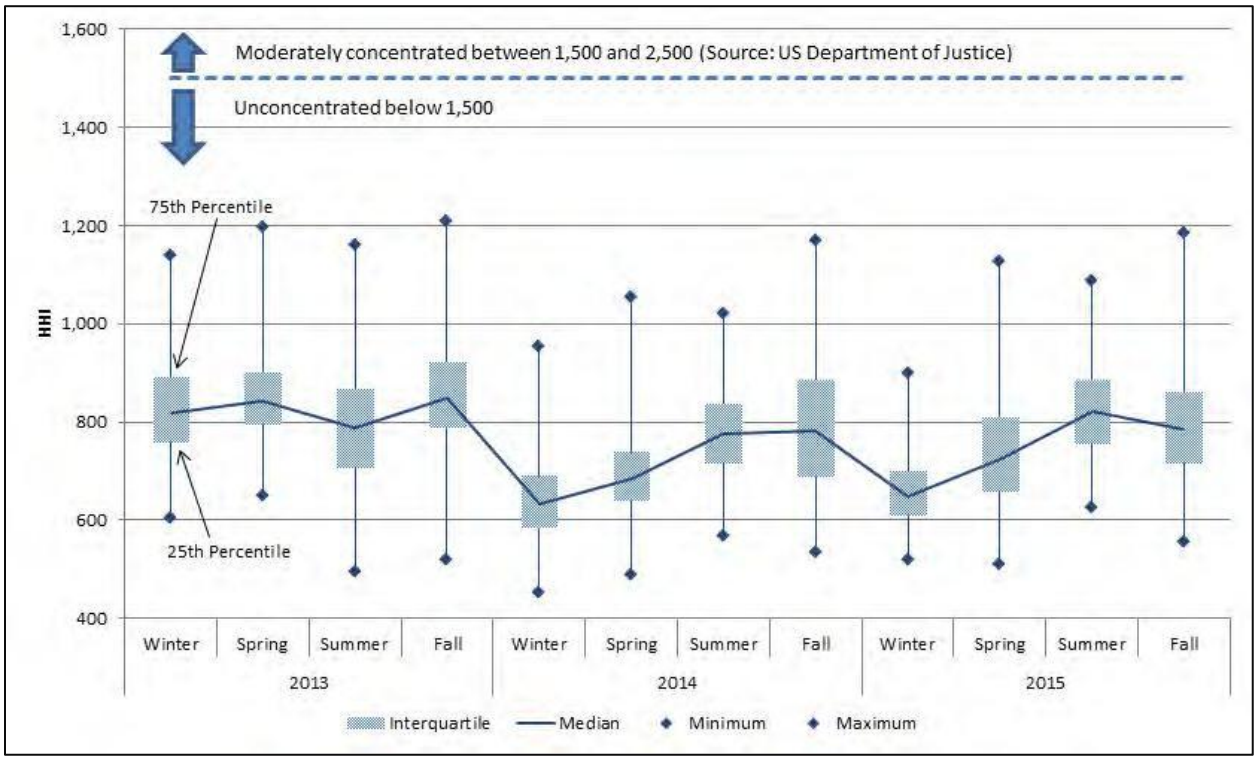
[18] The Department of Justice defines markets with an HHI below 1,500 points to be unconcentrated, an HHI between 1,500 and 2,500 points to be moderately concentrated, and an HHI above 2,500 points to be highly concentrated. US Department of Justice and the Federal Trade Commission, *Horizontal Merger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

[19] This issue was addressed in *ISO New England's Internal Market Monitor Second Quarter 2015 Quarterly Markets Report* (October 1, 2015), http://www.iso-ne.com/static-assets/documents/2015/10/qmr_q2_2015_10_1_2015_for_filing.pdf. Further enhancements to the IMM's competitiveness measures, that take account of affiliations, are being developed and will be included in future reports.

[20] The mapping of assets to ultimate parent companies is based on information provided to the ISO by participants. The mapping of assets to ultimate parent company will be periodically updated as new information becomes available.

[21] 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 likely not change our assessment.

Figure 2-15: Hourly HHI by Season, Winter 2013-Fall 2015



M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: January 29, 2016

RE: Generator Interconnection Revisions

At the February 5, 2016, meeting of the Participants Committee you will be asked to vote on generator interconnection revisions to Section II of the ISO New England Transmission, Markets and Services Tariff ("ISO-NE OATT") (the "Generator Interconnection Revisions"). At its January 26, 2016 meeting the Transmission Committee unanimously recommended Participants Committee support for the Generator Interconnection Revisions, which are included with the materials for the February 5 Participants Committee meeting.[1]

By way of background, during the second half of 2015 and into 2016, NEPOOL has been working with the ISO to develop revisions to the regional interconnection rules to improve the interconnection process and specifically to address some of the particular issues related to non-synchronous wind generators coming onto the system. The general goals of the Generator Interconnection Revisions are: (i) to reduce the time to interconnect new generators; (ii) to address some of the operational issues related to inverter-based generators; and (iii) to meet NERC modeling and performance requirements. Among the changes is a reactive power requirement that will apply to wind generators and that is similar to the requirement that the FERC has proposed in its November 19, 2015 notice of proposed rulemaking in Docket No. RM16-1. The changes being proposed are in the Large Generator Interconnection Procedures (Schedule 22 of the ISO-NE OATT), the Small Generator Interconnection Procedures (Schedule 23 of the ISO-NE OATT) and the Elective Transmission Upgrade Interconnection Procedures (Schedule 25 of the ISO-NE OATT).

The following resolution could be used for Participants Committee consideration of this matter:

> RESOLVED, that the Participants Committee supports the Generator Interconnection Revisions, as recommended by the Transmission Committee and as reflected in the materials distributed to the Participants Committee for its February 5, 2016 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

---

[1] An ISO memo describing the Generator Interconnection Revisions is also included with your materials for this agenda item.

ISO new england

memo

To: Transmission Committee

From: Al McBride, Director, Transmission Strategy & Services

Date: December 15, 2015

Subject: Proposed Changes to the Interconnection Procedures in Schedules 22, 23 and 25 of the ISO New England Open Access Transmission Tariff

At the **December 17, 2015** meeting of the Transmission Committee, ISO New England Inc. (the "ISO") will be presenting proposed changes to the Interconnection Procedures set forth in Schedules 22, 23 and 25 of the ISO New England Open Access Transmission Tariff[1] ("OATT") that are necessary to improve the current interconnection queue process ("Interconnection Process Improvements – Phase I"). The Interconnection Process Improvements – Phase I are a streamlined version of the changes that the ISO presented and reviewed with the Transmission Committee at the October 27 and November 12, 2015. The refined scope is responsive to stakeholders' feedback at the November meeting. This memorandum is provided to facilitate your review of the Interconnection Process Improvements – Phase I and discussions at the December meeting.

Brief Background

In recent years, the ISO has received written correspondences and engaged in various discussions regarding key issues in the interconnection queue process in New England, particularly the challenges being experienced by wind developers. Wind developers in New England – individually and through the RENEW[2] group–have requested improvements in both the timing and cost of Interconnection Studies,[3] and have cited challenges with the curtailment of wind generators in actual operations. They have cited the experiences of several of RENEW's members to claim the Interconnection Study process in New England takes too long to complete and can represent a significant cost to developers. These challenges were recently echoed by the American Wind Energy Association ("AWEA") in a petition for rulemaking requesting the Federal Energy Regulatory Commission ("FERC") initiate a rulemaking to revise the provisions of the *pro forma* Large Generator Interconnection Procedures/Agreement on the basis that the Transmission Providers nationwide are not performing Interconnection Studies in a timely and accurate manner.

[1] The Interconnection Procedures include Schedule 22 (Large Generator Interconnection Procedures or LGIP), Schedule 23 (Small Generator Interconnection Procedures or SGIP), and Schedule 25 (Elective Transmission Upgrade Interconnection Procedures or ETU IP).

[2] RENEW is a consortium of renewable energy developers and environmental advocates

[3] Interconnection Studies include the Feasibility Study, System Impact Study and Facilities Study.

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
413-540-4223
XXXX@iso-ne.com

iso-ne.com
isonewswire.com
@isonewengland
iso-ne.com/isotogo
iso-ne.com/isoexpress

Since incorporating the LGIP and LGIA in Schedule 22 of the OATT, the ISO, with full stakeholder support, has made significant enhancements to the Interconnection Procedures to address concerns unique to the region, and continuously reviews the interconnection processes for opportunities to improve transparency and efficiency. These efforts have improved the interconnection queue process. Indeed, as the public version of the interconnection queue shows,[4] substantially all generator Interconnection Requests made through 2014 have completed the System Impact Study phase or moved into the Interconnection Agreement and commercialization phases of the interconnection process. The one exception pertains to the Interconnection Requests for projects seeking to interconnect in Northern and Western Maine. In general, the average time for performing Interconnection Studies for projects requesting interconnection into non-Maine areas of the system has improved over time, with studies in those areas being completed in reduced timeframes compared to previous years.[5]

While interconnection queue processing is generally up to date in non-Maine areas of the system, there is a significant queue backlog in Maine due to Interconnection Requests for more than 4,000 MW of new generation, mostly wind resources, seeking to interconnect in Northern and Western Maine, which has been exacerbated by a steady stream of additional Interconnection Requests. The ISO has identified three primary sources of the queue backlog in Maine: (1) the underlying nature of the Maine transmission system; (2) the extent of oversubscription of requests to interconnect in Maine; and, (3) the nature of the generator technology being proposed.[6] Each of these factors introduces significant complexities to the Interconnection Studies, requiring more effort and time to complete those studies, and that does not even account for additional delays introduced by actions and inactions of individual Interconnection Customers; such as, frequent project modifications, untimely submissions of functioning models, and challenges to study/upgrade findings.

Summary of Changes as Originally Proposed

The rule changes, as presented by the ISO at the October and November Transmission Committee meetings, represented a specific set of interconnection process improvements that could be implemented expeditiously. At a high level, the changes sought to improve overall process efficiency by:

---

[4] The ISO's interconnection queue is available at http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue

[5] It is important to recognize that factors such as the location of the project (*e.g.*, proximity to the boundary of a major load serving interface) and earlier-queued project withdrawals continue to contribute to study delays for some projects in these areas of the system. In certain cases, the time to complete studies may be lengthened to factor in emerging transmission reliability expansion plans.

[6] Previous presentations providing additional details on the primary sources of the queue backlog in Maine include the presentations provided at the July 15, 2015 Reliability Committee/Transmission Committee Summer Meeting, August 2015 Reliability Committee Meeting, August 2015 Transmission Committee Meeting, and September 2015 Planning Advisory Committee Meeting. A detailed explanation of each of these sources is also provided in Comments of ISO New England Inc. filed on September 8, 2015, in Docket No. RM15-21-000.

- Requiring all Interconnection Customers to provide completed technical data (including models) called for in Appendix 1, Attachment A for the proposed project with the Interconnection Request. Correspondingly, the proposed changes reduced certain administrative deadlines during the Feasibility Study and System Impact Study stages of the process, as the technical data currently required with the signed study agreement would have already been provided with the Interconnection Request. By providing the data with the Interconnection Request, the ISO would be able to provide feedback regarding project design specifics at the Scoping Meeting, and would be able to perform a Feasibility Study focused on the expected areas of concerns;

- Modifying the scope of the Feasibility Study to provide screening analysis of the expected areas of concern to facilitate focus on the expected problems; thereby, providing meaningful information to Interconnection Customers early in the process and facilitating their determinations as to whether or not to move forward with their projects;

- Adding more clarity to the ISO's review and assessment of Material Modification requests throughout the interconnection process; and,

- Clarifying the distinction between a Base Case and the case developed at the start of an Interconnection Study (referred to as the "Study Case"), and making the Base Case available to Interconnection Customers (not just their third party consultants).

To reduce the time needed to complete Interconnection Studies for wind generators seeking to interconnect into weak areas of the system – such as, Northern and Western Maine – an objective of the ISO proposals was to make these types of generator projects more "study-ready," similar to conventional generators. More specifically, the proposed changes incorporated: (1) reactive performance requirements for wind generators, which would reduce the reliance on design of reactive solutions in the System Impact Study; and (2) new "up-front" design requirements for wind generators that were designed to increase readiness to initiate study analysis and reduce time to complete studies (*e.g.*, providing detailed project design, addressing weak grid performance as part of the Interconnection Request). These improvements were expected to reduce the likelihood of project modifications, particularly given the effect on queue backlog of poor quality data submissions and continued requests to perform Material Modification determinations.

Finally, the proposed changes sought to address curtailment and performance issues in system operations for wind generators, as well as meet modeling and performance requirements being introduced by new NERC standards by: (1) including a phase-in requirement for standardized component models and parameters for powerflows and dynamic cases; and, (2) incorporating a phase measurement unit ("PMU") requirement for all technologies with maximum facility output equal to or greater than 100 MW to, among other things, facilitate model validations.

Importantly, as the ISO has clearly stated, these changes alone would not resolve the queue backlog in Maine. Interconnection Customers there are seeking to interconnect their projects in an oversubscribed portion of the system that is at its performance limit with no remaining margin. Significant transmission

infrastructure is needed to integrate the proposed amounts of wind generation in Maine, and the ISO is committed to continuing discussions with stakeholders as to how to address these infrastructure issues. In the meantime, with the proposed changes, the ISO sought to speed the interconnection study process, and, concomitantly, the queue study wait time for those projects currently in queue backlog.

Overview Interconnection Process Improvements – Phase I (as Refined)

At the November meeting of the Transmission Committee, stakeholders expressed a clear desire to maintain flexibility in the interconnection process even where such flexibility might mean more Interconnection Study time. Indeed, when asked to articulate the problem stakeholders want the ISO to resolve, the feedback received by the ISO was that the problem is not with the *time* that it takes to complete Interconnection Studies; but rather, dealing with the *volume* of Interconnection Requests pending in Maine. At that meeting, stakeholders asked the ISO to consider whether the proposed changes could be streamlined so that these Phase 1 discussions could be concluded and the focus could be turned to the larger issues.

Based on stakeholders' feedback, the ISO has refined the scope of the proposed changes to the Interconnection Procedures in order to continue to offer the flexibility requested. The changes, as deleted, maintained or added, are summarized in the table, below.[7]

Original Set of Interconnection Improvements	Streamlined Set of Interconnection Improvements
Timeline for Providing Project Technical Data: Changes related to the requirement for complete technical data (including models) called for in Appendix 1, Attachment A to be submitted with Interconnection Request, including corresponding changes (e.g., reduction of administrative deadlines during Feasibility Study and System Impact Study, deletion of Appendix 1, Attachment B, deletion of Appendix 7, etc.).	Proposed changes deleted and currently effective pro forma language reinstated. However, under the existing rules, Interconnection Customers can choose to submit all of the technical data and models called for in Appendix 1, Attachment A with the Interconnection Request. Added language providing that, if an Interconnection Customer chooses to do so, then the ISO will discuss the detailed project design at the Scoping Meeting. **See LGIP, Section 3.3.4.** Maintained new form for wind and inverter-based generating facilities-specific data to be provided along with the Appendix 1, Attachment A, to speed the System Impact Study process.

[7] The table summarizes the changes made in Schedule 22 of the OATT. Note, however, that conforming changes, as well as ministerial/clean-up type changes have also been made in Schedules 23 and 25 of the OATT. Materials posted for the Transmission Committee's review reflect, in redlined text, the changes made to the Interconnection Procedures as they are currently in effect and not incremental changes to the versions reviewed by the Committee in November.

Interconnection Study Related Changes: **Feasibility Study** – Changes to streamline the Feasibility Study scope to a screening analysis-type study focusing on the expected areas of concern, and to the Point of Interconnection provisions. **System Impact Study** – Changes to include estimated date System Impact Study will start and conclude in study agreements. **Administrative deadlines** – Changes to the signed study agreement and comment deadlines.	Proposed changes to the Feasibility Study scope deleted and currently effective pro forma language reinstated. Added language to afford Interconnection Customers the option to request a screening analysis as initially proposed. **See LGIP, Section 6.2.** Proposed changes to System Impact Study agreements to include estimated start and end timeframes maintained. **See LGIP, Section 7, and System Impact Study Agreement.** Proposed timeline changes deleted.
Material Modification Clarifications: Changes to clarify ISO's review and assessment of proposed Material Modifications.	Proposed changes to the Material Modification provisions (except for the proposed clean-up changes in **LGIP, Section 4)** deleted and currently effective pro forma language reinstated. Added clarification to the "material impact" component of the Material Modification definition. Maintained proposed changes to allow for technical data to be "refreshed prior to the beginning of the System Impact Study. **See LGIP, Section 7.4.** Made certain clean up changes in 4.1 and 4.4
Interconnection Customer Access to Base Cases: Changes to clarify the distinction between a Base Case and the case prepared at the start of an Interconnection Study, and provide Interconnection Customers (as opposed to just their third party consultants) access to the Base Case.	Maintained proposed changes. **See LGIP, Sections 2.3, 6, 7, 8 and 10.**
Transition Rules: Changes to transmission rules, which sought to mimic previously used transition rules, and are consistent with Order No. 2003 transition rules.	Maintained proposed transition rules. **See LGIP, Section 5.**
Reactive Capability/Low Voltage Ride Through Requirements: Changes to remove reactive capability exemption for wind generating facilities, and apply the Low Voltage Ride Through requirements to wind and inverter-based technologies.	Maintained proposed changes to delete the reactive capability exemption for wind, and the extension of the Low Voltage Ride Through requirements to inverter-based technologies. However, revised proposed changes so that new power factor

	requirement applies to wind generators whose System Impact Study starts after the effective date of the proposed changes. **See LGIP, Appendix G, and LGIA, Article 9.**
Standard Models and PSCAD Model Requirements: Changes to include a phase-in requirement for standardized component models and parameters for powerflows and dynamic cases.	Maintained proposed changes for standardized models and dynamic cases, including PSCAD models for all wind and inverter-based technologies. **See LGIP, Section 3.3.4, and Appendix 1, Attachments A and B.**
Phase Measurement Unit: Changes to incorporate a PMU requirement for all technologies with maximum facility output equal to or greater than 100 MW.	Proposed changes deleted, to be addressed in a future effort.
Ministerial/clean-up type changes: Proposed clarifications to the following definitions: CNR Capability (and the associated fill-in the blank section in LGIA, Appendix C), and Interconnection Request. Proposed changes to require all deposits to the System Operator by electronic transfer. Proposed clean-up changes in Long Lead Facility provisions in LGIP, Section 3.2.3 Proposed clean-up change in LGIP, Section 3.3.1. Proposed changes for all Interconnection Requests to be submitted through IRTT, and other clean-up changes to the Interconnection Request Form in Appendix 1.	All proposed ministerial/clean-up type changes maintained.

Should you have any questions regarding the proposed Interconnection Process Improvements – Phase 1, please contact Al McBride at amcbride@iso-ne.com.

Draft Revisions

New Interconnection Requirements Project

January 26, 2016 TC Meeting (FOR VOTE)

As Voted by the TC

SCHEDULE 22

LARGE GENERATOR INTERCONNECTION PROCEDURES

seeking Capacity Network Import Interconnection Service, and in a manner that ensures intra-zonal deliverability by avoidance of the redispatch of other Capacity Network Resources or Elective Transmission Upgrades with Capacity Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Capacity Network Resource ("CNR") shall mean that portion of a Generating Facility that is interconnected to the Administered Transmission System under the Capacity Capability Interconnection Standard.

Capacity Network Resource Capability ("CNR Capability") shall mean: (i) in the case of a Generating Facility that is a New Generating Capacity Resource pursuant to Section III.13.1 of the Tariff or an Existing Generating Capacity Resource that is increasing its capability pursuant to Section III.13.1.2.2.5 of the Tariff, for Summer, the highest megawatt amount of the Capacity Supply Obligation obtained by the Generating Facility in accordance with Section III.13 of the Tariff, and, if applicable, as specified in a filing by the System Operator with the Commission in accordance with Section III.13.8.2 of the Tariff, net of any megawatt amount reductions resulting from terminations, retirements or permanent de-list bids in accordance with Section III.13 of the Tariff, and, for Winter, ~~shall be~~ the Summer CNR Capability multiplied by the ratio of the associated Winter Qualified Capacity divided by the associated Summer Qualified Capacity, or (ii) in the case of a Generating Facility that meets the criteria under Section 5.2.3 of this LGIP, the total megawatt amount determined pursuant to the hierarchy established in Section 5.2.3~~.~~, net of any megawatt amount reductions resulting from terminations, retirements or permanent de-list bids in accordance with Section III.13 of the Tariff. The CNR Capability shall not exceed the maximum net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90 degrees F for Summer and at or above 20 degrees F for Winter. Where the Generating Facility includes multiple production devices, the CNR Capability shall not exceed the aggregate maximum net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90 degrees F for Summer and at or above 20 degrees F for Winter.

Capacity Network Resource Group Study ("CNR Group Study") shall mean the study performed by the System Operator under Section III.13.1.1.2.3 of the Tariff to determine which resources qualify to participate in a Forward Capacity Auction.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Administered Transmission System, the scope of which is described in Section 6 of the Standard Large Generator Interconnection Procedures. The Interconnection Customer has the option to request either that the Interconnection Feasibility Study be completed as a separate and distinct study, or as part of the Interconnection System Impact Study. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 6 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 6 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 6 and Section 7.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to: (i) interconnect a new Generating Facility to the Administered Transmission System as either a CNR or a NR; (ii) make a Material Modification to a proposed Generating Facility with an outstanding Interconnection Request; (iii) increase the energy capability or capacity capability of an existing Generation Facility; (~~iii~~iv) make a Material Modification to the design or operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected with the Administered Transmission System; (~~iv~~v) commence participation in the wholesale markets by an existing Generating Facility that is interconnected with the Administered Transmission System; or (~~v~~vi) change from NR Interconnection Service to CNR Interconnection Service for all or part of a Generating Facility's capability. Interconnection Request shall not include: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's

System Impact Study, and there shall be only one final report, which will include the results of both Section 6 and Section 7.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Large Generating Facility shall mean a Generating Facility having a maximum gross capability at or above zero degrees F of more than 20 MW.

Long Lead Time Facility ("Long Lead Facility") shall mean a Generating Facility or an Elective Transmission Upgrade with an Interconnection Request for Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service, respectively, that has, as applicable, elected or requested long lead time treatment and met the eligibility criteria and requirements specified in Schedule 22 or Schedule 25 of Section II of the Tariff, respectively.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnifying Party.

Major Permits shall be as defined in Section III.13.1.1.2.2.2(a) of the Tariff.

Material Modification shall mean: (i) except as expressly provided in Section 4.4.1, those modifications to the Interconnection Request, including any of the technical data provided by the Interconnection Customer in Attachment A to the Interconnection Request or to the interconnection configuration, requested by the Interconnection Customer, that either require significant additional study of the same Interconnection Request and could substantially change the interconnection design, or have a material impact (*i.e.*, an evaluation of the proposed modification cannot be completed in less than ten (10) Business Days) on the cost or timing of any Interconnection Studies or upgrades associated with an Interconnection Request with a later queue priority date; (ii) a change to the design or operating

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The System Operator, Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement ("LGIA") shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility, that is included in this Schedule 22 to the Tariff.

Standard Large Generator Interconnection Procedures ("LGIP") shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in this Schedule 22 to the Tariff.

Study Case shall have the meaning specified in Sections 6.2 and 7.3 of this LGIP.

System Protection Facilities shall mean the equipment, including necessary signal protection communications equipment, required to protect (1) the New England Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the New England Transmission System or on other delivery systems or other generating systems to which the New England Transmission System is directly connected.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

SECTION 2. SCOPE, APPLICATION AND TIME REQUIREMENTS.

2.1 Application of Standard Large Generator Interconnection Procedures.

The LGIP and LGIA shall apply to Interconnection Requests pertaining to Large Generating Facilities. Except as expressly provided in the LGIP and LGIA, nothing in the LGIP or LGIA shall be construed to limit the authority or obligations that the Interconnecting Transmission Owner or System Operator, as applicable, has with regard to ISO New England Operating Documents.

2.2. Comparability.

The System Operator shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this LGIP. The System Operator and Interconnecting Transmission Owner will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by the Interconnecting Transmission Owner, its subsidiaries or Affiliates, or others.

2.3 Base Case Data.

System Operator, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, shall provide Base Case power flow, short circuit and stability databases, including all underlying assumptions, and contingency lists upon request to the Interconnection Customer and any third party consultant retained by the Interconnection Customer~~ or to any non-market affiliate~~. For the purposes of ~~the Interconnection Customer.~~this provision, Base Case data may include the electromagnetic transient network model that does not include proprietary electromagnetic transient equipment models. The recipient(s) of such information shall be subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy as well as any other applicable requirement under Applicable Laws and Regulations regulating disclosure or confidentiality of such information. System Operator is permitted to require that Interconnection Customer or the third party consultant~~ or non-market affiliate~~ sign a confidentiality agreement before the release of information governed by Section 13.1 or the ISO New England Information Policy, or the release of any other information that is commercially sensitive or Critical Energy Infrastructure Information. ~~To the extent that any applicable information is not covered by any applicable confidentiality/disclosure requirements, such information may be provided directly to the Interconnection Customer.~~ Such databases and lists, hereinafter referred to as Base Cases, shall include all generation projects and transmission projects that are proposed for the New England Transmission System and any Affected System and for which a transmission expansion plan has been submitted and approved by the applicable authority and which, in the sole judgment of the System Operator, may have an impact on the Interconnection Request. The Interconnection Customer, where applicable, shall provide Base Case Data to the Interconnecting Transmission Owner and System Operator to facilitate required Interconnection Studies.

2.4 No Applicability to Transmission Service.

Nothing in this LGIP shall constitute a request for, nor the provision of, any service except for Interconnection Service, including, but not limited to, transmission delivery service, local delivery service, distribution service, capacity service, energy service or Ancillary Services under any applicable tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

2.5 Time Requirements.

Parties that must perform a specific obligation under a provision of the Standard Large Generator Interconnection Procedure or Standard Large Generator Interconnection Agreement within a specified time period shall use Reasonable Efforts to complete such obligation within the applicable time period. A Party may, in the exercise of reasonable discretion and within the time period set forth by the applicable procedure or agreement, request that the relevant Party consent to a mutually agreeable alternative time schedule, such consent not to be unreasonably withheld.

SECTION 3. INTERCONNECTION REQUESTS.

3.1 General.

To initiate an Interconnection Request, an Interconnection Customer must comply with all of the requirements set forth in Section 3.3.1. The Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. The Interconnection Customer must comply with the requirements specified in Section 3.3.1 for each Interconnection Request even when more than one request is submitted for a single site.

Within three (3) Business Days after its receipt of a valid Interconnection Request, System Operator shall submit a copy of the Interconnection Request to Interconnecting Transmission Owner.

At Interconnection Customer's option, System Operator, Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point(s) of Interconnection to be studied no later than the execution of the Interconnection Feasibility Study Agreement, or the Interconnection System Impact Study Agreement if the Interconnection Customer elects not to pursue the Interconnection Feasibility Study.

All deposits that must be submitted to the System Operator under this LGIP, must be delivered to the System Operator by electronic transfer within the period specified in the respective provision.

3.2 Type of Interconnection Services and Long Lead Time Facility Treatment

At the time the Interconnection Request is submitted, the Interconnection Customer must request either CNR Interconnection Service or NR Interconnection Service, as described in Sections 3.2.1 and 3.2.2 below. An Interconnection Customer that meets the requirements to obtain CNR Interconnection Service shall obtain NR Interconnection Service up to the NR Capability upon completion of all requirements for NR Interconnection Service, including all necessary upgrades. Upon completion of all requirements for the CNR Interconnection Service, the Interconnection Customer shall also receive CNR Interconnection Service for CNR Capability. An Interconnection Customer that meets the requirements to obtain NR Interconnection Service shall receive NR Interconnection Service for the Interconnection Customer's NR Capability. At the time the Interconnection Request is submitted, the Interconnection Customer may also request Long Lead Facility treatment in accordance with Section 3.2.3.

3.2.1 Capacity Network Resource Interconnection Service

3.2.1.1 The Product.

The System Operator must conduct the necessary studies in conjunction with the Interconnecting Transmission Owner, and with other Affected Parties as appropriate and in accordance with applicable codes of conduct and confidentiality requirements, and the Interconnecting Transmission Owner and other Affected Parties as appropriate must construct the Network Upgrades needed to interconnect the Large Generating Facility in a manner comparable to that in which CNRs are interconnected under the CC Interconnection Standard. CNR Interconnection Service allows the Interconnection Customer's Large Generating Facility to be designated as a CNR, and to participate in the New England Markets, in accordance with Market Rule 1, Section III of the Tariff, up to the CNR Capability or as otherwise provided in the Tariff, on the same basis as existing CNRs, and to be studied as a CNR on the assumption that such a designation will occur.

3.2.1.2 The Studies.

All Interconnection Studies for CNR Interconnection Service shall assure that the Interconnection Customer's Large Generating Facility satisfies the minimum characteristics required to interconnect in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New

Facility or its counterparty in the case of an External ETU that clears in a Forward Capacity Auction, in accordance with Section III.13.2 of the Tariff, prior to the clearance of the Long Lead Facility.

3.2.3.2 Request for Long Lead Facility Treatment.

An Interconnection Customer requesting CNR Interconnection Service for its proposed Generating Facility or CNI Interconnection Service for its proposed controllable Merchant Transmission Facility or Other Transmission Facility External ETU, which the Interconnection Customer projects to have a development cycle that would not be completed until after the beginning of the Capacity Commitment Period associated with the next Forward Capacity Auction (after the election for the Long Lead Facility is made) may elect or request Long Lead Facility treatment in the following manner:

(a) An Interconnection Customer proposing a Generating Facility or a controllable Merchant Transmission Facility or Other Transmission Facility External ETU with a requested CNR Interconnection Service or CNI Interconnection Service ~~of~~equal to or greater than 100 MW may elect Long Lead Facility treatment at the time the Interconnection Request is submitted, together with the critical path schedule and deposits required in Section 3.2.3.3.

(b) An Interconnection Customer proposing a Generating Facility or a controllable Merchant Transmission Facility or Other Transmission Facility External ETU with a requested CNR Interconnection Service or CNI Interconnection Service under 100 MW may request Long Lead Facility treatment by submitting a written request to the System Operator for its review and approval, explaining why the Generating Facility or the controllable Merchant Transmission Facility or Other Transmission Facility External ETU cannot achieve Commercial Operation by the beginning of the Capacity Commitment Period associated with the next Forward Capacity Auction (after the election for Long Lead Facility treatment is made), together with the critical path schedule and deposits required in Section 3.2.3.3. In reviewing the request, the System Operator shall evaluate the feasibility of the Generating Facility or the controllable Merchant Transmission Facility or Other Transmission Facility External ETU achieving Commercial Operation to meet an earlier Capacity Commitment Period based on the information provided in the request and the critical path schedule submitted pursuant to Section 3.2.3.3, in a manner similar to that performed under Section III.13.3.2 of the Tariff. Within forty-five (45) Business Days after its receipt of the request for Long Lead Facility treatment, the System Operator shall notify the Interconnection Customer in writing whether the request has been granted or denied. If the System Operator determines that the Generating Facility or the controllable Merchant

the previous critical path schedule update, the Interconnection Customer must include in the critical path update documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule.

(2) Long Lead Facility Deposits.

(a) Deposits. In addition to the deposits required elsewhere in the LGIP in the case of a Generating Facility or the ETU IP for External ETU, at the time of its request for Long Lead Facility treatment, in accordance with Section 3.2.3.3, and by each deadline for which a New Generating Capacity Resource is required to provide financial assurance under Section III.13.1.9.1 of the Tariff, the Interconnection Customer must provide a separate deposit in the amount of 0.25*(Forward Capacity Auction Starting Price~~/~~ ($/kW-mo)/2)*requested CNR Capability or CNI Capability. For each calculation of the deposit, the System Operator shall use the Forward Capacity Auction Starting Price in effect for the upcoming Forward Capacity Auction at the time of that calculation, pursuant to Section III.13.2.4 of the Tariff, or the Forward Capacity Auction Starting Price for the previous Forward Capacity Auction in the case where the Forward Capacity Auction Starting Price in effect for the upcoming Forward Capacity Auction has not yet been calculated. The total amount of deposits shall not exceed the Non-Commercial Capacity Financial Assurance Amount that the Long Lead Facility would be required to provide if the Long Lead Facility or its counterparty cleared in the upcoming Forward Capacity Auction, in accordance with Section III.13.1.9.1 of the Tariff. The Long Lead Facility deposits will be fully refunded (with interest to be calculated in accordance with Section 3.6) (i) if the Interconnection Customer withdraws the Interconnection Request, pursuant to Section 3.6, within thirty (30) Calendar Days of the Scoping Meeting or of the completion of the System Impact Study (including restudy of the System Impact Study), pursuant to Section 7, or (ii) once the Long Lead Facility or its counterparty clears in a Forward Capacity Auction.

(b) Reductions. Ten (10) percent of the Long Lead Facility deposits collected pursuant to Section 3.2.3.3(2)(a) shall be non-refundable if the Interconnection Customer withdraws its Interconnection Request (except as provided in Section 3.2.3.3(2)(a)) after the Long Lead Facility or its counterparty fails to qualify or qualifies and fails to clear in the Forward Capacity Auction that follows the first Forward Capacity Auction for which the Long Lead Facility or its counterparty could qualify based on the Commercial Operation Date specified in the initial critical path schedule for the Long Lead Facility. An additional five (5) percent of the Long Lead

of the Elective Transmission Upgrade, the Import Capacity Resource) in a Forward Capacity Auction prior to the Long Lead Facility, shall be removed.

3.2.3.6 Participation in Earlier Forward Capacity Auctions.

An Interconnection Customer with a Long Lead Facility may, without loss of Queue Position, elect to participate in an earlier Forward Capacity Auction than originally anticipated, but only if the election to accelerate is made to the System Operator in writing within thirty (30) Calendar Days of the Scoping Meeting or within thirty (30) Calendar Days of the completion of the System Impact Study (but before the Long Lead Facility and the results of the associated System Impact Study are incorporated into the Base Cases). Otherwise, such an election shall be considered a Material Modification.

3.3 Valid Interconnection Request.

3.3.1 Initiating an Interconnection Request.

To initiate an Interconnection Request, Interconnection Customer must submit all of the following to the System Operator in the manner specified in Appendix 1 Interconnection Request to this LGIP: (i) an initial deposit of $50,000, (ii) a completed application in the form of Appendix 1~~, (~~,(iii) all information and deposits required under Section 3.2, and (iv) in the case of a request for CNR Interconnection Service, demonstration of Site Control or, in the case of a request for NR Interconnection Service, demonstration of Site Control or a posting of an additional deposit of $10,000. Interconnection Customer does not need to demonstrate Site Control where the Interconnection Request is for a modification to the Interconnection Customer's existing Large Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the modification proposed in the Interconnection Request does not require additional real property. The portions of the deposit of $50,000 that have not been applied as provided in this Section 3.3.1 shall be refundable if (i) the Interconnection Customer withdraws the Interconnection Request, pursuant to Section 3.6, within ten (10) Business Days of the Scoping Meeting, or (ii) if the Interconnection Customer executes an LGIA. Otherwise, any unused balance of the deposit of $50,000 shall be non-refundable and applied on a pro-rata basis to offset costs incurred by Interconnection Customers with lower Queue Positions that are subject to re-study, as determined by the System Operator in accordance with the provisions of this LGIP, as a result of the withdrawal of an Interconnection Request with a higher Queue Position.

The deposit of $50,000 shall be applied toward the costs incurred by the System Operator associated with the Interconnection Request and Long Lead Facility treatment, as well as, the costs of the Interconnection

Feasibility Study and/or the Interconnection System Impact Study, including the cost of developing the study agreements and their attachments, and the cost of developing the LGIA.

If, in the case of a request for NR Interconnection Service, the Interconnection Customer demonstrates Site Control within the cure period specified in Section 3.3.3 after submitting its Interconnection Request, the additional deposit of $10,000 shall be refundable; otherwise, that deposit shall be applied as provided in Section 3.1, including, toward the costs of any Interconnection Studies pursuant to the Interconnection Request, the cost of developing the study agreement(s) and associated attachment(s), and the cost of developing the LGIA.

The expected Initial Synchronization Date of the new Large Generating Facility, of the increase in capacity of the existing Generating Facility, or of the implementation of the Material Modification to the existing Generating Facility shall not exceed seven (7) years from the date the Interconnection Request is received by the System Operator, unless the Interconnection

Customer demonstrates that such time required to actively engineer, permit and construct the new Large Generating Facility or increase in capacity of the existing Generating Facility or implement the Material Modification to the existing Generating Facility will take longer than the seven year period. Upon such demonstration, the Initial Synchronization Date may succeed the date the Interconnection Request is received by the System Operator by a period of greater than seven (7) years so long as the Interconnection Customer, System Operator, and Interconnecting Transmission Owner agree~~;~~, such agreement shall not be unreasonably withheld.

3.3.2 Acknowledgment of Interconnection Request.

System Operator shall acknowledge receipt of the Interconnection Request within five (5) Business Days of receipt of the request and attach a copy of the received Interconnection Request to the acknowledgement. With the System Operator's acknowledgement of a valid Interconnection Request, the System Operator shall provide to the Interconnection Customer an Interconnection Feasibility Study Agreement in the form of Appendix 2 or an Interconnection System Impact Study Agreement in the form of Appendix 3.

3.3.3 Deficiencies in Interconnection Request.

An Interconnection Request will not be considered to be a valid request until all items in Section 3.3.1 have been received by the System Operator. If an Interconnection Request fails to meet the requirements

set forth in Section 3.3.1, the System Operator shall notify the Interconnection Customer within five (5) Business Days of receipt of the initial Interconnection Request of the reasons for such failure and that the Interconnection Request does not constitute a valid request. Interconnection Customer shall provide the System Operator the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. Failure by Interconnection Customer to comply with this Section 3.3.3 shall be treated in accordance with Section 3.6.

3.3.4 Scoping Meeting.

Within ten (10) Business Days after receipt of a valid Interconnection Request, System Operator shall establish a date agreeable to Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, for a Scoping Meeting, and such date shall be no later than thirty (30) Calendar Days from receipt of the valid Interconnection Request, unless otherwise mutually agreed upon by the Parties.

The purpose of the Scoping Meeting shall be (i) to discuss the estimated timeline for completing all applicable Interconnection Studies, and alternative interconnection options, (ii) to exchange pertinent information including any transmission data that would reasonably be expected to impact such interconnection options, (iii) to analyze such information, (iv) to determine the potential feasible Points of Interconnection, and (v) to discuss any other information necessary to facilitate the administration of the Interconnection Procedures. ~~If a~~A PSCAD model is required for all wind and inverter-based Large Generating Facilities. If a PSCAD model is required for other Large Generating Facilit~~ies~~y types~~,~~, the Parties shall discuss this at the Scoping Meeting. If the Interconnection Customer provided the technical data called for in Appendix 1, Attachment A with the Interconnection Request, the Parties shall discuss the detailed project design at the Scoping Meeting.

The Parties will bring to the meeting such technical data, including, but not limited to: (i) general facility loadings, (ii) general instability issues, (iii) information regarding general short circuit issues, (iv) general voltage issues, and (v) general reliability issues as may be reasonably required to accomplish the purpose of the meeting. The Parties will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Interconnection Customer shall designate its Point of Interconnection, pursuant to Section 6.1, and one or more available alternative Point(s) of Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose.

Within five (5) Business Days following the Scoping Meeting Interconnection Customer shall notify the System Operator, in writing, (i) whether it wants the Interconnection Feasibility Study to be completed as a separate and distinct study or as part of the Interconnection System Impact Study; (ii) if requesting the Interconnection Feasibility Study be completed as a separate and distinct study, which of the alternate study scopes is being selected pursuant to Section 6.2; and (iii) the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection for inclusion in the attachment to the Interconnection Feasibility Study Agreement, or the Interconnection System Impact Study Agreement if the Interconnection Customer elects not to pursue the Interconnection Feasibility Study.

3.4 OASIS Posting.

The System Operator will maintain on its OASIS a list of all Interconnection Requests in its Control Area. The list will identify, for each Interconnection Request: (i) the maximum summer and winter megawatt electrical output; (ii) the location by county and state; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected Initial Synchronization Date; (v) the status of the Interconnection Request, including Queue Position; (vi) the type of Interconnection Service being requested (i.e., CNR Interconnection Service or NR Interconnection Service); and (vii) the availability of any studies related to the Interconnection Request; (viii) the date of the Interconnection Request; (ix) the type of Generating Facility to be constructed (combined cycle, base load or combustion turbine and fuel type); and (x) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed. Except in the case of an Affiliate, the list will not disclose the identity of the Interconnection Customer until the Interconnection Customer executes an LGIA or requests that the System Operator and Interconnecting Transmission Owner jointly file an unexecuted LGIA with the Commission. Before participating in a Scoping Meeting with an Interconnection Customer that is also an Affiliate, the Interconnecting Transmission Owner shall post on OASIS an advance notice of its intent to do so. The System Operator shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection Study reports shall be posted to the System Operator's OASIS site subsequent to the meeting between the System Operator, Interconnecting Transmission Owner, and Interconnection Customer to discuss the applicable study results. The System Operator shall also post any known deviations in the Large Generating Facility's Initial Synchronization Date.

3.5 Coordination with Affected Systems.

shall pay to System Operator, Interconnecting Transmission Owner, and any Affected Parties all costs prudently incurred with respect to that Interconnection Request prior to System Operator's receipt of notice described above. The Interconnection Customer must pay all monies due before it is allowed to obtain any Interconnection Study data or results.

The System Operator shall update the OASIS Queue Position posting. Except as otherwise provided elsewhere in this LGIP, the System Operator and the Interconnecting Transmission Owner shall arrange to refund to the Interconnection Customer any portion of the Interconnection Customer's deposit or study payments that exceeds the costs incurred, including interest calculated in accordance with section 35.19a(a)(2) of the Commission's regulations, or arrange to charge to the Interconnection Customer any amount of such costs incurred that exceed the Interconnection Customer's deposit or study payments, including interest calculated in accordance with section 35.19a(a)(2) of the Commission's regulations. In the event of such withdrawal, System Operator, subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information, shall provide, at Interconnection Customer's request, all information developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

SECTION 4. QUEUE POSITION.

4.1 General.

System Operator shall assign a Queue Position based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form in Appendix 1 to this LGIP, and Interconnection Customer provides such information in accordance with Section 3.3.3, then System Operator shall assign Interconnection Customer a Queue Position based on the date the application form was originally filed. ~~A Material Modification pursuant to Section 4.4.2 shall be treated in accordance with Section 4.4.~~

Except as otherwise provided in this Section 4.1, the Queue Position of each Interconnection Request will be used to determine: (i) the order of performing the Interconnection Studies; (ii) the order in which Interconnection Requests for CNR Interconnection Service and CNI Interconnection Service will be included in the CNR Group Study; and (iii) the cost responsibility for the facilities and upgrades necessary to accommodate the Interconnection Request. A higher queued Interconnection Request is one

that has been placed "earlier" in the queue in relation to another Interconnection Request that is lower queued.

4.1.1 Order of Interconnection Requests in the CNR Group Study

Participation in a CNR Group Study shall be a prerequisite to achieve CNR Interconnection Service and CNI Interconnection Service. The CNR Group Study (to be conducted in accordance with Section III.13.1.1.2.3 of the Tariff) shall include all Interconnection Requests for CNR Interconnection Service and CNI Interconnection Service that have an associated New Capacity Show of Interest Form that was submitted during the New Capacity Show of Interest Submission Window for the purpose of qualification for participation in the same Forward Capacity Auction for a Capacity Commitment Period, in accordance with Section III.13.1.1.2 of the Tariff, as well as Long Lead Facilities in accordance with Section 3.2.3. Where a CNR Interconnection Service or CNI Interconnection Service Interconnection Request with a lower Queue Position is associated with a New Capacity Show of Interest Form that was submitted for qualification to participate in a particular Forward Capacity Auction for a Capacity Commitment Period and another CNR Interconnection Service or CNI Interconnection Service Interconnection Request with a higher Queue Position is not associated with a New Capacity Show of Interest Form that was submitted for qualification until a subsequent Forward Capacity Auction, the CNR Interconnection Service or CNI Interconnection Service Interconnection Request with the lower Queue Position will be included in the CNR Group Study prior to the CNR Interconnection Service or the CNI Interconnection Service Interconnection Request with the higher Queue Position.

However, where an Interconnection Customer with a CNR Interconnection Service Interconnection Request submits a New Capacity Show of Interest Form for qualification to participate in a particular Forward Capacity Auction for a Capacity Commitment Period and identifies in that New Capacity Show of Interest Form one or more Elective Transmission Upgrade Interconnection Request(s) for an Internal ETU that is not already included in the network model pursuant to Section III.12 of the Tariff for the particular Forward Capacity Auction, the CNR Interconnection Request will be included in the CNR Group Study at the lowest of the CNR Interconnection Request's or its associated Elective Transmission Upgrade Interconnection Request(s) for the Internal ETU's Queue Position. Where multiple Interconnection Customers' CNR Interconnection Service Interconnection Requests are associated with the same lower Queue Position for an Elective Transmission Upgrade Interconnection Request for an

Cluster Window shall be in accordance with Section 7.4, for all Interconnection Requests assigned to the same Queue Cluster Window. The Queue Cluster Window shall have a fixed time interval based on fixed annual opening and closing dates. Any changes to the established Queue Cluster Window interval and opening or closing dates shall be announced with a posting on System Operator's OASIS beginning at least one hundred and eighty (180) Calendar Days in advance of the change and continuing thereafter through the end date of the first Queue Cluster Window that is to be modified.

Clustering Interconnection System Impact Studies shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the New England Transmission System's capabilities at the time of each study. The System Operator may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Large Generating Facility.

4.3 Transferability of Queue Position.

An Interconnection Customer may transfer its Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change. The Interconnection Customer must notify the System Operator, in writing, of any transfers of Queue Position and must provide the System Operator with the transferee's contact information, and System Operator shall notify Interconnecting Transmission Owner and any Affected Parties of the same.

4.4 Modifications.

The Interconnection Customer shall submit to System Operator and Interconnecting Transmission Owner, in writing, modifications to any information provided in the Interconnection Request, including its attachments. The Interconnection Customer shall retain its Queue Position if the modifications are in accordance with Sections 4.4.1 or 4.4.4, or are determined not to be Material Modifications pursuant to Section 4.4.2. The System Operator will notify the Interconnecting Transmission Owner, and, when System Operator deems it appropriate in accordance with applicable codes of conduct and confidentiality requirements, it will notify any Affected Party of such modifications.

A request to: (1) increase the energy capability or capacity capability output of a Generating Facility above that specified in an Interconnection Request, an existing Interconnection Agreement (whether executed or filed in unexecuted form with the Commission), or as established pursuant to Section 5.2 of this LGIP shall require a new Interconnection Request for the incremental increase and such

Interconnection Request will receive the lowest Queue Position available at that time for the purposes of cost allocation and study analysis; and (2) change from NR Interconnection Service to CNR Interconnection Service, at any time, shall require a new Interconnection Request for CNR Interconnection Service and such Interconnection Request will receive the lowest Queue Position available at that time for the purposes of cost allocation and study analysis. Notwithstanding the foregoing, an Interconnection Customer with an Interconnection Request for CNR Interconnection Service has until the Forward Capacity Auction for which the associated Capacity Commitment Period begins less than seven (7) years (or the years agreed to pursuant to Section 3.3.1 or Section 4.4.5) from the date of the original Interconnection Request for CNR Interconnection Service to clear the entire megawatt amount for which CNR Interconnection Service was requested. A new Interconnection Request for CNR Interconnection Service will be required for the Generating Facility to participate in any subsequent auctions.

During the course of the Interconnection Studies, either the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes do not constitute a Material Modification and are acceptable to the Parties, such acceptance not to be unreasonably withheld, System Operator and the Interconnecting Transmission Owner shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 6.4, Section 7.6 and Section 8.5 as applicable and Interconnection Customer shall retain its Queue Position.

4.4.1 Prior to the commencement ~~return~~ of the ~~executed~~ Interconnection System Impact Study ~~Agreement to System Operator~~, modifications permitted under this Section shall include specifically: (a) a decrease of up to 60 percent of electrical output (MW) of the proposed project; (b) modifying the technical parameters associated with the Large Generating Facility technology or the Large Generating Facility step-up transformer impedance characteristics; and (c) modifying the interconnection configuration.

4.4.2 Prior to making any modification other than those specifically permitted by Sections 4.4.1 and 4.4.4, Interconnection Customer may first request that the System Operator and Interconnecting Transmission Owner evaluate whether such modification is a Material Modification. In response to

Interconnection Customer's request, the System Operator in consultation with the Interconnecting Transmission Owner, and in consultation with any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, shall evaluate, at the Interconnection Customer's cost, the proposed modifications prior to making them and the System Operator will inform the Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection, except those deemed acceptable under Sections 4.4.1, 6.1, 7.2 or so allowed elsewhere, shall constitute a Material Modification. The Interconnection Customer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

4.4.3 Upon receipt of Interconnection Customer's request for modification that does not constitute a Material Modification and therefore is permitted under this Section 4.4, the System Operator in consultation with the Interconnecting Transmission Owner and in consultation with any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, shall commence and perform any necessary additional studies as soon as practicable, but in no event shall the System Operator, Interconnecting Transmission Owner, or Affected Party commence such studies later than thirty (30) Calendar Days after receiving notice of Interconnection Customer's request. Any additional studies resulting from such modification shall be done at Interconnection Customer's cost.

4.4.4 Extensions of less than three (3) cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility to which the Interconnection Request relates are not material and should be handled through construction sequencing, provided that the extension(s) do not exceed seven (7) years from the date the Interconnection Request was received by the System Operator.

4.4.5 Extensions of three (3) or more cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility to which the Interconnection Request relates or any extension of a duration that results in the Initial Synchronization Date exceeding the date the Interconnection Request was received by the System Operator by seven (7) or more years is a Material Modification unless the Interconnection Customer demonstrates to the System Operator due diligence, including At-Risk Expenditures, in pursuit of permitting, licensing and construction of the Large Generating Facility to meet the Commercial Operation Date, In-Service Date or Initial Synchronization Date provided in the Interconnection Request. Such demonstration shall be based on

evidence to be provided by the Interconnection Customer of accomplishments in permitting, licensing, and construction in an effort to meet the Commercial Operation Date, In-Service Date or Initial Synchronization Date provided in this Interconnection Request. Such evidence may include filed documents, records of public hearings, governmental agency findings, documentation of actual construction progress or documentation acceptable to the System Operator showing At-Risk Expenditure made previously, including the previous four (4) months. If the evidence demonstrates that the Interconnection Customer did not undertake reasonable efforts to meet the Commercial Operation Date, In-Service Date or Initial Synchronization Date specified in the Interconnection Request, or demonstrates that reasonable efforts were not undertaken until four (4) months prior to the request for extension, the request for extension shall constitute a Material Modification. The Interconnection Customer may then withdraw the proposed Material Modification or proceed with a new Interconnection Request for such modification.

SECTION 5. PROCEDURES FOR TRANSITION.

5.1 Queue Position for Pending Requests.

5.1.1 Any Interconnection Customer assigned a Queue Position prior to ~~February 1, 2009,~~[Effective Date], shall retain that Queue Position subject to Section 4.4 of the LGIP.

5.1.1.1 If an Interconnection Study Agreement has not been executed prior to ~~February 1, 2009,~~[Effective Date], then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with the version of this LGIP in effect on ~~February 1, 2009~~[Effective Date] (or as revised thereafter).

~~**5.1.1.2** If an Interconnection Study Agreement has been executed prior to February 1, 2009, such Interconnection Study shall be completed in accordance with the terms of such agreement~~

5.1.1.2 If an Interconnection Study Agreement has been executed prior to [Effective Date] and is actively under study, such Interconnection Study shall be completed in accordance with the terms of such agreement. If an Interconnection Study Agreement has been executed prior to [Effective Date], but the Interconnection Study has not commenced, such Interconnection Study shall be completed, and any subsequent Interconnection Studies shall be processed, in accordance with the version of the LGIP in effect on [Effective Date]. If the Interconnection Study has not commenced, within sixty (60) Calendar Days from ~~the~~ [Effective Date], Interconnection Customer shall submit an updated Interconnection

Request together with completed attachments and models required therein to facilitate the System Operator, in coordination with Interconnecting Transmission Owner and Affected Party as deemed appropriate by the System Operator, conduct of the Interconnection Study. Updates to the Interconnection Request and attachments thereto will be subject to review pursuant to Section 4.4 of this LGIP. Notwithstanding any other provision in this LGIP, if the Interconnection Customer fails to meet these requirements within a period not to exceed sixty (60) Calendar Days, the Interconnection Request shall be deemed withdrawn.

5.1.2 Transition Period. To the extent necessary, the System Operator, Interconnection Customers with an outstanding Interconnection Request (i.e., an Interconnection Request for which an LGIA has neither been executed nor submitted to the Commission for approval prior to ~~February 1, 2009),~~[Effective Date]), Interconnecting Transmission Owner and any other Affected Parties, shall transition to proceeding under the version of the LGIP in effect as of ~~February 1, 2009~~[Effective Date] (or as revised thereafter) within a reasonable period of time not to exceed sixty (60) Calendar Days. The use of the term "outstanding Interconnection Request" herein shall mean any Interconnection Request, on ~~February 1, 2009:~~[Effective Date]: (i) that has been submitted, together with the required deposit and attachments, but not yet accepted by the System Operator; (ii) where the related LGIA has not yet been submitted to the Commission for approval in executed or unexecuted form, (iii) where the relevant Interconnection Study Agreements have not yet been executed, or (iv) where any of the relevant Interconnection Studies are in process but not yet completed. Any Interconnection Customer with an outstanding ~~request~~Interconnection Request as of the effective date of this LGIP may request a reasonable extension of ~~any deadline, otherwise~~the next applicable~~,~~ deadline if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension, not to exceed sixty (60) Calendar Days, shall be granted by the System Operator to the extent consistent with the intent and process provided for under this LGIP.

5.1.3 One-Time Election for CNR Interconnection Service at Queue Position Assigned Prior to February 1, 2009.

An Interconnection Customer with an outstanding Interconnection Request will be eligible to make a one-time election to be considered for CNR Interconnection Service at the Queue Position assigned prior to February 1, 2009. The Interconnection Customer's one-time election must be made by the end of the New Generating Capacity Show of Interest Submission Window for the fourth Forward Capacity Auction. The Interconnection Customer's one-time election may also include a request for Long Lead Facility Treatment, which shall be subject to review pursuant to Section 3.2.3, and, if applicable, a request

Interconnection Feasibility Study, including the development of the study agreement and its attachment(s). The Interconnection Customer shall pay the invoiced amounts, to the extent such amounts are greater than the initial deposit, within thirty (30) Calendar Days of receipt of invoice. The System Operator shall continue to hold any amounts on deposit until settlement of the final invoice with the Interconnection Customer and the Interconnecting Transmission Owner.

On or before the return of the executed Interconnection Feasibility Study Agreement to the System Operator and Interconnecting Transmission Owner, the Interconnection Customer shall provide the technical data called for in Appendix 1, Attachment B. If the Interconnection Customer does not provide all such technical data when it delivers the Interconnection Feasibility Study Agreement, the System Operator shall notify the Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection Feasibility Study Agreement and the Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed Interconnection Feasibility Study Agreement or deposit.

If the Interconnection Feasibility Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting, a substitute Point of Interconnection identified by the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, and acceptable to the Parties, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and re-studies shall be completed pursuant to Section 6.4 as applicable. For the purpose of this Section 6.1, if the Parties cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 3.3.4, shall be the substitute.

6.2 Scope of Interconnection Feasibility Study.

The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the Administered Transmission System with available data and information. ~~The Interconnection Feasibility Study does not require detailed model development.~~

The Interconnection Feasibility Study will consider the ~~base case~~Base Case as well as all generating facilities and Elective Transmission Upgrades (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request; and (iv) have no Queue Position but have executed an Interconnection Agreement or requested that an unexecuted Interconnection Agreement be filed with the Commission~~.~~ (the "Study Case" for the Interconnection Feasibility Study). An Interconnection Customer with a CNR Interconnection Request may also request that the Interconnection Feasibility Study include a preliminary, non-binding, analysis to identify potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff, based on a limited set of assumptions to be specified by the Interconnection Customer and reflected in Attachment A to the Interconnection Feasibility Study Agreement.

The Interconnection Feasibility Study will consist of a power flow, including thermal analysis and voltage analysis, and short circuit analysis. The Interconnection Feasibility Study report will provide (i) a list of facilities, and a non-binding good faith estimate of cost responsibility; (ii) a non-binding good faith estimated time to construct the Interconnection Facilities and Network Upgrades; (iii) a protection assessment to determine the required Interconnection Facilities; and may provide (iv) an evaluation of the siting of Interconnection Facilities and Network Upgrades; and (v) identification of the likely permitting and siting process including easements and environmental work for Interconnection Facilities and Network Upgrades.

Alternatively, in the case where the Interconnection Customer requests that the Interconnection Feasibility Study be completed as a separate and distinct study, the Interconnection Customer may provide the technical data called for in Appendix 1, Attachment A with the executed Interconnection Feasibility Study Agreement and request that the Interconnection Feasibility Study consist of limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient analysis, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Large Generating Facility's interconnection given recent study experience and as discussed at the Scoping Meeting. In this case, the Interconnection Feasibility Study report will provide (i) the study findings; and, (ii) a preliminary description of and~~, to the extent readily available to the Interconnecting Transmission Owner,~~ a non-binding good faith order of magnitude estimated cost of (unless such cost

estimate is waived by the Interconnection Customer) ~~estimated cost of~~ and the time to construct the Interconnection Facilities and Network Upgrades necessary to interconnect the Large Generating Facility as identified within the scope of the analysis performed as part of the study.

To the extent the Interconnection Customer requested a preliminary analysis as described in this Section 6.2, the Interconnection Feasibility Study report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

6.3 Interconnection Feasibility Study Procedures.

The System Operator in coordination with Interconnecting Transmission Owner shall utilize existing studies to the extent practicable when it performs the study. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the Interconnection Feasibility Study no later than forty-five (45) Calendar Days after System Operator and Interconnecting Transmission Owner receive the fully executed Interconnection Feasibility Study Agreement, study deposit and required technical data in accordance with Section 6.1. At the request of the Interconnection Customer or at any time the System Operator or the Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, the System Operator shall notify the Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If the System Operator is unable to complete the Interconnection Feasibility Study within that time period, the System Operator shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. ~~Upon~~In such circumstances, upon request, the System Operator with input from the Interconnecting Transmission Owner shall provide all supporting documentation, workpapers and relevant ~~pre-Interconnection Request and post-Interconnection Request~~Study Case power flow and short circuit databases that have been developed for the Interconnection Feasibility Study to any third party consultant retained by the Interconnection Customer~~ or to any non-market affiliate of the Interconnection Customer~~. The recipient(s) of such information shall be subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information. To the extent that any applicable information is not covered by any applicable confidentiality/disclosure requirements, such information may be provided directly to the Interconnection Customer.

6.3.1 Meeting with Parties.

Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and the System Operator shall be responsible for generating only one final report, which will include the results of both Section 6 and Section 7.

Within five (5) Business Days following the Interconnection Feasibility Study results meeting, or subsequent to the Scoping Meeting within five (5) Business Days following the receipt of designation of the Point(s) of Interconnection and type of study to be performed pursuant to Section 3.3.4, if the Interconnection Customer did not request that the Interconnection Feasibility Study be completed as a separate and distinct study, the System Operator and Interconnecting Transmission Owner shall provide to Interconnection Customer the Interconnection System Impact Study Agreement, which includes a non-binding good faith estimate of the cost and timeframe for commencing and completing the Interconnection System Impact Study. The Interconnection System Impact Study Agreement shall provide that the Interconnection Customer shall compensate the System Operator and Interconnecting Transmission Owner for the actual cost of the Interconnection System Impact Study, including the cost of developing the study agreement and its attachment(s) and the cost of developing the LGIA.

7.2 Execution of Interconnection System Impact Study Agreement.

The Interconnection Customer shall execute the Interconnection System Impact Study Agreement and deliver the executed Interconnection System Impact Study Agreement to the System Operator no later than thirty (30) Calendar Days after its receipt along with a demonstration of Site Control and the technical data called for in Appendix 1, Attachment A, and the Interconnection Customer shall also deliver ~~simultaneously~~ a refundable deposit. An Interconnection Customer does not need to demonstrate Site Control where the Interconnection Request is for a modification to the Interconnection Customer's existing Large Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the modification proposed in the Interconnection Request does not require additional real property. The deposit for the study shall be: (i) the greater of 100 percent of the estimated cost of the study or $250,000; or (ii) the lower of 100 percent of the estimated costs of the study or $50,000, if the Interconnection Customer can provide: (1) evidence of applications for all Major Permits, as defined in Section III.13.1.1.2.2.2(a) of the Tariff, required in support of the Interconnection Request or written certification that Major Permits are not required, or (2) evidence acceptable to the System Operator of At-Risk Expenditures (excluding Interconnection Study costs) totaling at least the amounts of money described in (i) above; or (iii) the lower of 100 percent of the estimated costs of the study or $50,000, if the Interconnection Request is for a modification to an existing Large Generating

Facility that does not increase the energy capability or capacity capability of the Large Generating Facility.

The deposit shall be applied toward the cost of the Interconnection System Impact Study, including the cost of developing the study agreement and its attachment(s) and the cost of developing the LGIA. Any difference between the study deposit and the actual cost of the Interconnection System Impact Study shall be paid by or refunded to the Interconnection Customer, except as otherwise provided in Section 13.3. In accordance with Section 13.3, the System Operator and/or the Interconnecting Transmission Owner shall issue to the Interconnection Customer an invoice for the costs of Interconnection System Impact Study that have been incurred by the System Operator and/or the Interconnecting Transmission Owner for the System Impact Study, including the study agreement and its attachment(s) and the LGIA. If the Interconnection Customer elects the deposit described in (ii) above, the System Operator and the Interconnecting Transmission Owner may, in the exercise of reasonable discretion, invoice the Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection System Impact Study on each month. The Interconnection Customer shall pay the invoiced amounts, to the extent such amounts are greater than the initial deposit, within thirty (30) Calendar Days of receipt of invoice. The System Operator shall continue to hold the amounts on deposit until settlement of the final invoice with the Interconnection Customer and the Interconnecting Transmission Owner.

On or before the return of the executed Interconnection System Impact Study Agreement to the System Operator and Interconnecting Transmission Owner, the Interconnection Customer shall provide the technical data called for in Appendix 1, Attachment A; provided that if a PSCAD model for a non-wind or non-inverter-based Large Generating Facility was determined to be needed at the Scoping Meeting, then the Interconnection Customer shall have ninety (90) Calendar Days from the date of the Scoping Meeting or the execution of the System Impact Study Agreement (whichever is later) to provide the PSCAD model.

If the Interconnection Customer does not provide all such technical data when it delivers the Interconnection System Impact Study Agreement, the System Operator shall notify the Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection System Impact Study Agreement and the Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed Interconnection System Impact Study Agreement or deposit.

If the Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting or the Interconnection Feasibility Study, a substitute Point of Interconnection identified by the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, and acceptable to each Party, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and re-studies shall be completed pursuant to Section 7.6 as applicable. For the purpose of this Section 7.2, if the Parties cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement or Interconnection System Impact Study depending on whether Interconnection Customer requested that the Interconnection Feasibility Study be completed as a separate and distinct study or as part of the Interconnection System Impact Study, as specified pursuant to Section 3.3.4, shall be the substitute.

7.3 Scope of Interconnection System Impact Study.

The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability and operation of the New England Transmission System. The Interconnection System Impact Study will consider the ~~base case~~Base Case as well as all generating facilities and Elective Transmission Upgrades (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request; and (iv) have no Queue Position but have executed an Interconnection Agreement or requested that an unexecuted Interconnection Agreement be filed with the Commission~~.~~ (the "Study Case" for the Interconnection System Impact Study). An Interconnection Customer with a CNR Interconnection Request may also request that the Interconnection System Impact Study include a preliminary, non-binding, analysis to identify potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff, based on a limited set of assumptions to be specified by the Interconnection Customer and reflected in Attachment A to the Interconnection System Impact Study Agreement.

The Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, a power flow analysis, including thermal analysis and voltage analysis, a system protection analysis and any other analyses, such as electromagnetic transient analysis, that are deemed necessary by the System Operator in consultation with the Interconnecting Transmission Owner. The Interconnection System Impact Study report will state the assumptions upon which it is based, state the results of the analyses, and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Interconnection System Impact Study report will provide (i) a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility; (ii) a non-binding good faith estimated time to construct; (iii) a protection assessment to determine the required protection upgrades; and may provide (iv) an evaluation of the siting of the Interconnection Facilities and Network Upgrades; and (v) identification of the likely permitting and siting process including easements and environment work. To the extent the Interconnection Customer requested a preliminary analysis as described in this Section 7.3, the Interconnection System Impact Study report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

7.4 Interconnection System Impact Study Procedures.

The System Operator shall coordinate the Interconnection System Impact Study with the Interconnecting Transmission Owner, and with any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, that is affected by the Interconnection Request pursuant to Section 3.5 above. The System Operator and Interconnecting Transmission Owner shall utilize existing studies to the extent practicable when it performs the study. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the Interconnection System Impact Study within ninety (90) Calendar Days after the receipt of the Interconnection System Impact Study Agreement, study deposit, demonstration of Site Control, if Site Control is required, and required technical data in accordance with Section 7.2. If System Operator or Interconnecting Transmission Owner uses Clustering, the System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to deliver a completed Interconnection System Impact Study within ninety (90) Calendar Days after the close of the Queue Cluster Window.

At the request of the Interconnection Customer or at any time the System Operator or Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the

Interconnection System Impact Study, the System Operator shall notify the Interconnection Customer as to the schedule status of the Interconnection System Impact Study. If the System Operator and Interconnecting Transmission Owner are unable to complete the Interconnection System Impact Study within the time period, the System Operator shall notify the Interconnection Customer and provide an estimated start date if the study has not commenced and completion date with an explanation of the reasons why additional time is required. ~~Upon~~In such circumstances, upon request, the System Operator and Interconnecting Transmission Owner shall provide all supporting documentation, workpapers and relevant ~~pre-Interconnection Request and post-Interconnection Request~~Study Case power flow, short circuit and stability databases that have been developed for the Interconnection System Impact Study to any third party consultant retained by the Interconnection Customer~~ or to any non-market affiliate of the Interconnection Customer.~~. The recipient(s) of such information shall be subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information. To the extent that any applicable information is not covered by any applicable confidentiality/ disclosure requirements, such information may be provided directly to the Interconnection Customer.

The System Operator shall notify the Interconnection Customer when the Interconnection System Impact Study is expected to commence within sixty-five (65) Calendar Days. Interconnection Customer will be permitted to update the technical data provided in Appendix 1 and Attachment A, and submit modifications to that technical data to the System Operator no later than sixty (60) Calendar Days from the date that the System Operator notified the Interconnection Customer ~~after receipt of the System Operator's notification~~ that the Interconnection System Impact Study is expected to commence. Such modifications will not be deemed Material Modifications provided they meet the requirements of Section 4.4.1 of this LGIP.

Where sufficient time has elapsed since the initial Scoping Meeting, within ten (10) Business Days after notifying the Interconnection Customer that the Interconnection System Impact Study is expected to commence, the System Operator may convene a second Scoping Meeting for the purpose of providing updated information to the Interconnection Customer in preparation for the submittal of updates to the technical data.

7.5 Meeting with Parties.

Within ten (10) Business Days of providing an Interconnection System Impact Study report to Interconnection Customer, the System Operator shall convene a meeting of the Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, to discuss the results of the Interconnection System Impact Study.

Within ~~five (5~~ten (10) Business Days following the study results meeting, the Interconnection Customer shall provide to the System Operator written notice that it will either pursue the Interconnection Facilities Study or waive the Interconnection Facilities Study and elect an expedited interconnection. If the Interconnection Customer waives the Facilities Study, it shall commit to the following milestones in the LGIA: (i) Siting approval for the Generating Facility and Interconnection Facilities; (ii) Engineering of Interconnection Facilities approved by Interconnecting Transmission Owner; (iii) Ordering of long lead time material for Interconnection Facilities and system upgrades; (iv) Initial Synchronization Date; and (v) Commercial Operation Date.

Within thirty (30) Calendar Days of the Interconnection Customer receiving the Interconnection System Impact Study report, the Interconnection Customer shall provide written comments on the report or written notice that it has no comments on the report. The System Operator shall issue a final Interconnection System Impact Study report within fifteen (15) Business Days of receiving the Interconnection Customer's comments or promptly upon receiving the Interconnection Customer's notice that it will not provide comments.

7.6 Re-Study.

If re-study of the Interconnection System Impact Study is required due to (i) a higher queued project dropping out of the queue, (ii) a modification of a higher queued project subject to Section 4.4, (iii) re-designation of the Point of Interconnection pursuant to Section 7.2, (iv) a re-assessment of the upgrade responsibilities of an Elective Transmission Upgrade associated with an Import Capacity Resource(s) or a Generating Facility after the Import Capacity Resource(s) or the Generating Facility receives a Capacity Supply Obligation in accordance with Section III.13 of the Tariff, or (v) a modification to a transmission project included in the Base Case, the System Operator shall notify the Interconnection Customer and Interconnecting Transmission Owner in writing.

Each re-study shall be conducted serially based on the Queue Position of each Interconnection Customer, and each re-study shall take no longer than sixty (60) Calendar Days from the date the re-study

good faith cost estimate. Such cost estimates either individually or in the aggregate will be provided in the final study report.

At the request of the Interconnection Customer or at any time the System Operator or Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection Facilities Study, System Operator shall notify the Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, as to the schedule status of the Interconnection Facilities Study. If the System Operator is unable to complete the Interconnection Facilities Study and issue a draft Interconnection Facilities Study report within the time required, the System Operator shall notify the Interconnection Customer, Interconnecting Transmission Owner and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, and provide an estimated completion date and an explanation of the reasons why additional time is required.

The Interconnection Customer and appropriate Affected Parties may, within thirty (30) Calendar Days after receipt of the draft report, provide written comments to the System Operator and Interconnecting Transmission Owner, which the System Operator shall include in the final report. The System Operator shall issue the final Interconnection Facilities Study report within fifteen (15) Business Days of receiving the Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. The System Operator may reasonably extend such fifteen-day period upon notice to the Interconnection Customer if the Interconnection Customer's comments require the System Operator or Interconnecting Transmission Owner to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Report. ~~Upon~~In such circumstances, upon request, the System Operator and Interconnecting Transmission Owner shall provide the Interconnection Customer and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, or any third party consultant retained by the Interconnection Customer ~~or to any non-market affiliate of the Interconnection Customer~~ supporting documentation, with workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study. The recipient(s) of such information shall be subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information. To the extent that any applicable information is not

to provide transmission service or Interconnection Service based upon the results of the Optional Interconnection Study. The System Operator shall use Reasonable Efforts to coordinate the study with any Affected Systems that may be affected by the types of Interconnection Services that are being studied. The System Operator and Interconnecting Transmission Owner shall utilize existing studies to the extent practicable in conducting the Optional Interconnection Study.

The Optional Interconnection Study will consist of a short circuit analysis, a stability analysis, a power flow analysis, including thermal analysis and voltage analysis, a system protection analysis, and any other analyses that are deemed necessary by the System Operator in consultation with the Interconnecting Transmission Owner.

10.3 Optional Interconnection Study Procedures.

The executed Optional Interconnection Study Agreement, the prepayment, and technical and other data called for therein must be provided to the System Operator and Interconnecting Transmission Owner within ten (10) Business Days of the Interconnection Customer receipt of the Optional Interconnection Study Agreement. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the Optional Interconnection Study within a mutually agreed-upon time period specified within the Optional Interconnection Study Agreement. If the System Operator and Interconnecting Transmission Owner are unable to complete the Optional Interconnection Study within such time period, the System Operator shall notify the Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required. ~~Upon~~In such circumtances, upon request, the System Operator and Interconnecting Transmission Owner shall provide the Interconnection Customer supporting documentation and workpapers and databases or data developed in the preparation of the Optional Interconnection Study to any third party consultant retained by the Interconnection Customer~~ or to any non-market affiliate of the Interconnection Customer.~~. The recipient(s) of such information shall be subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information. To the extent that any applicable information is not covered by any applicable confidentiality/disclosure requirements, such information may be provided directly to the Interconnection Customer.

10.4 Meeting with Parties.

Within ten (10) Business Days of providing an Optional Interconnection Study report to Interconnection Customer, System Operator will convene a meeting of the Interconnecting Transmission Owner,

APPENDIX 1

INTERCONNECTION REQUEST

The undersigned Interconnection Customer submits this request to interconnect its Large Generating Facility to the Administered Transmission System under Schedule 22 - Large Generator Interconnection Procedures ("LGIP") of the ISO New England Inc. Open Access Transmission Tariff (the "Tariff"). Capitalized terms have the meanings specified in the Tariff.

PROJECT INFORMATION

Proposed Project Name:_____

1. This Interconnection Request is for (check one):

_____ A proposed new Large Generating Facility

_____ An increase in the generating capacity or a modification that has the potential to be a Material Modification of an existing Generating Facility

_____ Commencement of participation in the wholesale markets by an existing Generating Facility

_____ A change from Network Resource Interconnection Service to Capacity Network Resource Interconnection Service

2. The types of Interconnection Service requested:

_____ Network Resource Interconnection Service (energy capability only)

_____ Capacity Network Resource Interconnection Service (energy capability and capacity capability)

If Capacity Network Resource Interconnection Service, does Interconnection Customer request Long Lead Facility treatment? Check: ____Yes or ___ No

If yes, provide, together with this Interconnection Request, the Long Lead Facility deposit and other required information as specified in Section 3.2.3 of the LGIP, including (if the Large Generating Facility will be less than 100 MW) a justification for Long Lead Facility treatment.

3. This Interconnection Customer requests (check one, selection is not required as part of the initial Interconnection Request):

_____ ~~A~~An Interconnection Feasibility Study to be completed as a separate and distinct study

_____ ~~A~~An Interconnection System Impact Study with the Feasibility Study to be performed as the first step of the study

(The Interconnection Customer shall select either option and may revise any earlier selection up to within five (5) Business Days following the Scoping Meeting.)

4. The Interconnection Customer shall provide the following information:

Address or Location of the Facility (including Town/City, County and State):

_____

_____

_____

Approximate location of the proposed Point of Interconnection (information is not required as part of the initial Interconnection Request):

_____

Type of Generating Facility to be Constructed:_____

Generating Facility Fuel Type:

_____

Generating Facility Capacity (MW):

	Maximum Net MW Electrical Output	**Maximum Gross MW Electrical Output**
At or above 90 degrees F		
At or above 50 degrees F		
At or above 20 degrees F		
At or above 0 degrees F		

General description of the equipment configuration (# of units and GSUs):

_____

_____

Requested Commercial Operations Date:

_____

Requested Initial Synchronization Date:

_____

Requested In Service Date:

_____

Evidence of Site Control (check one):

_____ **If for Capacity Network Resource Interconnection Service, Site Control is provided herewith, as required.**

_____ **If for Network Resource Interconnection Service: (Check one)**

___ **Is provided herewith**

___ **In lieu of evidence of Site Control, a $10,000 deposit is provided ~~herewith~~ (refundable within the cure period as described in Section 3.3.3 of the LGIP).**

In order for an Interconnection Request to be considered a valid request, it must:

(a) Be accompanied by a deposit of $50,000.00~~,~~ that is provided electronically and which may be refundable in accordance with Section 3.3.1 of the LGIP;

(b) For Capacity Network Resource Interconnection Service, include documentation demonstrating Site Control. If for Network Resource Interconnection Service, demonstrate Site Control or post an additional deposit of $10,000.00. If the Interconnection Customer with an Interconnection Request for Network Resource Interconnection Service demonstrates Site Control within the cure period specified in Section 3.3.1 of the LGIP, the additional deposit of $10,000.00 shall be refundable (An Interconnection Customer does not need to demonstrate Site Control for an Interconnection Request for a modification to its existing Large Generating Facility where the Interconnection Customer has certified that it has Site Control and that the proposed modification does not require additional real property);

(c) Include a detailed map~~ (2 copies),~~, such as a map of the quality produced by the U.S. Geological Survey, which clearly indicates the site of the new facility and pertinent surrounding structures; and

(d) Include all information required on the Interconnection Request form and attachments thereto; and

(e) Include the deposit and all information required for Long Lead Facility treatment, if such treatment is requested in accordance with Section 3.2.3 of the LGIP.

The Interconnection Request must be submitted to the System Operator via the Interconnection Request Tracking Tool or IRTT, a web-based application for submitting, tracking and viewing Interconnection Requests available on the ISO New England website.

Attachment A (page 1)
To Appendix 1
Interconnection Request
Technical Data Required For
Interconnection System Impact Study

The technical data required below must be submitted no later than the date of execution of the System Impact Study Agreement pursuant to Section 7.2 of the LGIP.

LARGE GENERATING FACILITY DATA

UNIT RATINGS

Kva	°°F	Voltage
Power Factor		
Speed (RPM)		Connection (e.g. Wye) _____
Short Circuit Ratio		Frequency, Hertz _____
Stator Amperes at Rated Kva		Field Volts _____
Max Turbine MW	°°F	

GREATEST UNIT RATING AT AMBIENT TEMPERATURE OF 90 ^{o} OR ABOVE

Gross Unit Rating (MW)	Gross Lagging (MVAR)
Net Unit Rating (MW)	Gross Leading (MVAR)
Station Service (MW)	Station Service (MVAR)
Temperature (^{o}F)	

GREATEST UNIT RATING AT AMBIENT TEMPERATURE OF 50° OR ABOVE

Gross Unit Rating (MW)	Gross Lagging (MVAR)
Net Unit Rating (MW)	Gross Leading (MVAR)
Station Service (MW)	Station Service (MVAR)
Temperature (^{o}F)	

Attachment A (page 2)
To Appendix 1
Interconnection Request
Technical Data Required For
Interconnection System Impact Study

GREATEST UNIT RATING AT AMBIENT TEMPERATURE OF 20° OR ABOVE

Gross Unit Rating (MW)	Gross Lagging (MVAR)
Net Unit Rating (MW)	Gross Leading (MVAR)
Station Service (MW)	Station Service (MVAR)
Temperature (^{o} F)	

GREATEST UNIT RATING AT AMBIENT TEMPERATURE OF 0° OR ABOVE

Gross Unit Rating (MW)	Gross Lagging (MVAR)
Net Unit Rating (MW)	Gross Leading (MVAR)
Station Service (MW)	Station Service (MVAR)
Temperature (^{o}F)	

COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H	=	kW sec/kVA
Moment-of-Inertia, WR2	=	lb. ft.2

REACTANCE DATA (PER UNIT-RATED KVA)

	DIRECT AXIS	**QUADRATURE AXIS**
Synchronous – saturated	Xdv	Xqv
Synchronous – unsaturated	Xdi	Xqi
Transient – saturated	X’dv	X’qv
Transient – unsaturated	X’di	X’qi
Subtransient – saturated	X”dv	X”qv
Subtransient – unsaturated	X”di	X”qi
Negative Sequence – saturated	X2v	
Negative Sequence – unsaturated	X2i	
Zero Sequence – saturated	X0v	
Zero Sequence – unsaturated	X0i	

Leakage Reactance	Xlm

Attachment A (page 3)
To Appendix 1
Interconnection Request
Technical Data Required For
Interconnection System Impact Study

FIELD TIME CONSTANT DATA (SEC)

Open Circuit	T'qo	T'do
Three-Phase Short Circuit Transient	T'd3	T'q
Line to Line Short Circuit Transient	T'd2	
Line to Neutral Short Circuit Transient	T'd1	
Short Circuit Subtransient	T"d	T"q
Open Circuit Subtransient	T"do	T"qo

ARMATURE TIME CONSTANT DATA (SEC)

Three Phase Short Circuit	Ta3
Line to Line Short Circuit	Ta2
Line to Neutral Short Circuit	Ta1

NOTE: If requested information is not applicable, indicate by marking "N/A."

Attachment A (page 4)
To Appendix 1
Interconnection Request
Technical Data Required For
Interconnection System Impact Study

MW CAPABILITY AND PLANT CONFIGURATION

LARGE GENERATING FACILITY DATA

ARMATURE WINDING RESISTANCE DATA (PER UNIT)

Positive	R1		
Negative	R2		
Zero	R0		

Rotor Short Time Thermal Capacity I^2t	=		
Field Current at Rated kVA, Armature Voltage and PF	=	Amps	
Field Current at Rated kVA and Armature Voltage, 0 PF		Amps	
Three Phase Armature Winding Capacitance	=	Microfarad	
Field Winding Resistance	=	ohms	°C
Armature Winding Resistance (Per Phase)	=	ohms	°C

CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

Attachment A (page 5)
To Appendix 1
Interconnection Request
Technical Data Required For
Interconnection System Impact Study

GENERATOR STEP-UP TRANSFORMER DATA RATINGS

Capacity Self-cooled/Maximum Nameplate

/ Kva

Voltage Ratio Generator side/System side/Tertiary

/ kV

Winding Connections Generator side/System Side/Tertiary (Delta or Wye)

/

Fixed Taps Available

Present Tap Setting

IMPEDANCE

Positive	Z1 (on self-cooled kVA rating)	%	X/R
Zero	Z0 (on self-cooled kVA rating)	%	X/R

Attachment A (page 6)
To Appendix 1
Interconnection Request
Technical Data Required For
Interconnection System Impact Study

EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer ("PSS") for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

WIND AND INVERTER-BASED GENERATORS

~~Number of generators to be interconnected pursuant to~~
~~this Interconnection Request: _____~~
~~Elevation: _____ _____ Single Phase _____ Three Phase~~
~~Inverter manufacturer, model name, number, and version:~~

~~List of adjustable set points for the protective equipment or software:~~

A completed Attachment A-1 Supplementary Wind and Inverter-Based Generating Facility Form to this Attachment A, must be supplied for all Interconnection Requests for wind and inverter-based Generating Facilities.

MODEL REQUIREMENTS

For all ~~generator~~Generating Facility types: A completed, fully functioning, public (*i.e.,* non-proprietary ~~or~~, non-confidential) Siemens PTI's ("PSSE") power flow model or other compatible formats, such as IEEE and General Electric Company Power Systems Load Flow ("PSLF") data sheet , must be supplied

with this Attachment A. If additional ~~non-proprietary or non-confidential~~public data sheets are more appropriate to the proposed device then they shall be provided and discussed at the Scoping Meeting. For all Interconnection Studies commencing after January 1, 2017, all power flow models must be standard library models in PSS/E or applicable applications. After January 1, 2017, user-models will not be accepted.

~~A PSCAD model shall be provided pursuant to Section 7.2 of the LGIP if deemed required at the Scoping Meeting.~~

Attachment A (page 7)
To Appendix 1
Interconnection Request
Technical Data Required For
Interconnection System Impact Study

A PSCAD model for all wind and inverter-based Generating Facilities must be supplied with this Attachment A. If a PSCAD model is deemed required for other Generating Facility types at the Scoping Meeting, such PSCAD model must be provided to the System Operator within ninety (90) Calendar Days of the Scoping Meeting date or the executed Interconnection System Impact Study Agreement (whichever is later). A benchmarking analysis, consistent with the requirements in the ISO New England Planning Procedures, confirming acceptable performance of the PSS/E model in comparison to the PSCAD model, shall be provided at the time PSCAD model is submitted.

Attachment A (page 8)
To Appendix 1
Interconnection Request
Technical Data Required For
Interconnection System Impact Study

INDUCTION GENERATORS:

(*) Field Volts:

(*) Field Amperes:

(*) Motoring Power (kW):

(*) Neutral Grounding Resistor (If Applicable):

(*) I_2^2t or K (Heating Time Constant):

(*) Rotor Resistance:

(*) Stator Resistance:

(*) Stator Reactance:

(*) Rotor Reactance:

(*) Magnetizing Reactance:

(*) Short Circuit Reactance:

(*) Exciting Current:

(*) Temperature Rise:

(*) Frame Size:

(*) Design Letter:

(*) Reactive Power Required In Vars (No Load):

(*) Reactive Power Required In Vars (Full Load):

(*) Total Rotating Inertia, H: Per Unit on KVA Base

Note: Please consult System Operator prior to submitting the Interconnection Request to determine if the information designated by (*) is required.

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Attachment A to the Interconnection Request is true and accurate.

For Interconnection Customer:_____Date:_____

Attachment A-1 (page 1)
To Attachment A of Appendix 1
Supplementary Wind
and Inverter-Based
Generating Facility Form

SUPPLEMENTARY WIND AND INVERTER-BASED GENERATING FACILITY DATA FORM

1. Attach a Geographic Map Demonstrating the Project Layout and its Interconnection to the Power Grid. *(Specify the name of the attachment here)*

2. Attach a Bus-Breaker Based One-line Diagram (The diagram should include each of the individual unit generators, generator number, rating and terminal voltage.) *(Specify the name of the attachment here)*

2.1 Collection system detail impedance sheet

If a collector system is used, attach a collector system data sheet in accordance with the one-line diagram attached above. The data sheet should include: the type, length Z_0, Z_1 and Xc/B of each circuit (feeder and collector string).

Specify the name of the attachment here: _____

Attachment A-1 (page 2)
To Attachment A of Appendix 1
Supplementary Wind
and Inverter-Based
Generating Facility Form

2.2 Collection system aggregate (equivalent) model data sheet

Attach an aggregate (equivalent) collection system data sheet. The data table should include: the type, length, Z_0, Z_1 and Xc/B of the equivalent circuits (feeders and collector strings).

Specify the name of the attachment here: _____

3. Summary of the Unit Models in the wind or inverter-based generating facility *(List all different unit models in the facility)*

Manufacturer Model	Type of this WTG* (if applicable)	Generator Unit numbers in the field	Number(s) of these Units	Maximum Output of this Unit(MW)	Total MW
……..					

* Type 1 – Cage rotor induction generators
Type 2 – Induction generators with variable rotor resistance
Type 3 – Doubly-fed asynchronous generators with rotor-side converter
Type 4 – Full-power converter interface

Repeat the following sections from 6 to 14 for each different unit model.

Attachment A-1 (page 3)
To Attachment A of Appendix 1
Supplementary Wind
and Inverter-Based
Generating Facility Form

4. Unit Detail Information

Unit Manufacturer Model	
Terminal Voltage	
Rating of Each Unit (MVA)	
Maximum Gross Electrical Output (MW)	
Minimum Gross Electrical Output(MW)	
Lagging Reactive Power Limit at Rated Real Power Output (MVAR)	
Leading Reactive Power Limit at Rated Real Power Output (MVAR)	
Lagging Reactive Power Limit at Zero Real Power Output (MVAR)	
Leading Reactive Power Limit at Zero Real Power Output (MVAR)	
Station Service Load(MW, MVAR)	
Minimum short circuit ratio(SCR) requirement by manufacturer	
On which bus the minimum SCR is required by manufacturer	
What voltage level the minimum SCR is required by manufacturer	
Positive sequence Xsource	
Zero sequence Xsource	

Attachment A-1 (page 4)
To Attachment A of Appendix 1
Supplementary Wind
and Inverter-Based
Generating Facility Form

5. Unit GSU – _____

Nameplate rating(MVA)	
Total number of the GSUs	
Voltages, generator side/system side	
Winding connections, low voltage/high voltage	
Available tap positions on high voltage side	
Available tap positions on low voltage side	
Will the GSU operate as an LTC?	
Desired voltage control range if LTC	
Tap adjustment time (Tap switching delay + switching time) if LTC	
Desired tap position if applicable	
Impedance, Z1, X/R ratio	
Impedance, Z0, X/R ratio	

6. Low Voltage Ride Through(LVRT) – _____*(Specify the Manufacturer Model of this Unit)*

Does each Unit have LVRT capability?

Yes__ _____ No__

If yes, please provide:

6.1 Unit LVRT mode activation and release condition:

When operating at maximum real power, what is the Unit terminal voltage for LVRT mode activation? _____

When operating at maximum real power, what is the Unit terminal voltage for releasing LVRT mode after it is activated? _____

If there is different LVRT activation and release logic, please state here _____

Attachment A-1 (page 5)
To Attachment A of Appendix 1
Supplementary Wind
and Inverter-Based
Generating Facility Form

6.2 A wind or other inverter-based generating facility technical manual from the manufacturer including description of LVRT functionality:

Attach the file and specify the name of the attachment here:

_____

6.3 Does the wind or other inverter-based generating facility technical manual attached above include a reactive power capability curve?

Yes _____ No __

If no, attach the file and specify the name of the attachment here:

_____

7. Low Voltage Protection (considering LVRT functionality)

(Specify the Manufacturer Model of this Unit)

Low Voltage Setting (pu)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

8. High Voltage Protection - _____(Specify the Manufacturer Model of this Unit)

High Voltage Setting (pu)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

Attachment A-1 (page 6)
To Attachment A of Appendix 1
Supplementary Wind
and Inverter-Based
Generating Facility Form[A1]

9. Low Frequency Protection - _____(Specify the Manufacturer Model of this Unit)

Low Frequency Setting(Hz)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

10. High Frequency Protection - _____(Specify the Manufacturer Model of this Unit)

High Frequency Setting(Hz)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

Please make sure the settings in section 8 through 11 comply with NERC and NPCC standards for generator protection relays.

11. Unit Reactive Power Control - ____ (Specify the Manufacturer Model of this Unit)

11.1 What are the options for the Unit reactive power control (check all available)?

_____ Control the voltage at the Unit terminal

____Control constant power factor at the Unit terminal

____Control constant power factor at the low side of the station main transformer

____Control constant power factor at the high side of the station main transformer

____Control voltage at the low side of the station main transformer

____Control voltage at the high side of the station main transformer

____ Other options. Please describe if select others_____

11.2 In all the control options selected above, please list the options in which the Unit is able to control its terminal voltage to prevent low/high voltage tripping.

_____

11.3 What is the desired control mode from the selected options above? Specify the control plan in this mode. For example: control voltage at which bus to what schedule.

_____

12. Wind or inverter-based generating facility Model

(All model files provided in section 13 should be compatible with Siemens PTI's PSS/E version currently in use at ISO New England)

12.1 Power flow model

12.1.1 A *. RAW file including **aggregated/equivalent** wind or inverter-based generating facility power flow model with appropriate parameters and settings.

Attach the *.RAW file and specify the name of the attachment here:

_____

12.1.2 A *. RAW file including **detailed** wind or inverter-based generating facility power flow model with appropriate parameters and settings. *(Optional)*

Attach the *.RAW file and specify the name of the attachment here:

_____

12.2 Dynamic simulation model

(Please note that the dynamic model must match the aggregated/equivalent power flow model provided above. Attach the following information for each of the models.)

12.2.1 Wind or inverter-based generating facility Model _____(Please Specify the Manufacturer Model)

12.2.2 A compiled PSS/E dynamic model for the turbines (a *.LIB or *.OBJ file)

1.1 ***Attach the *.LIB or *.OBJ file and specify the name of the attachment here:***

1.2 _____

12.2.3 A dynamic data file with appropriate parameters and settings for the turbines (typically a *.DYR file)

1.3 ***Attach the *.DYR file and specify the name of the attachment here:***

1.4 _____

12.2.4 PSS/E wind or inverter-based generating facility model user manual for the WTG

1.5 ***Attach the and specify the name of the attachment here:***

1.6 _____

1.7 **Rrepeat the above sections from 6 to 14 for each different wind or inverter-based generating facility model)**

13. Power Plant Controller

Will the wind or inverter-based generating facility be equipped with power plant controller, which has the ability to centrally control the output of the units?

1.8 Yes__ No__

1.9 If yes, please provide:

13.1 Manufacturer model of the power plant controller

1.10 _____

13.2 What are the reactive power control strategy options of the power plant controller?

-
-

…….

13.3 Which of the control option stated above is being used in current operation?

_____

13.4 Is the power plant controller able to control the unit terminal voltages to prevent low/high voltage

tripping?

Yes__ No__

Please provide the park controller technical manual from the manufacturer

Attach the file and specify the name of the attachment here:

_____

14. Station Transformer

Transformer Name		
Nameplate ratings(MVA)		
Total number of the main transformer(s)		
Voltages, High/Low/Tertiary (kV)		
Winding connections, High/Low/Tertiary		
Available tap positions on high voltage side		
Available tap positions on low voltage side		
Will the transformer operate as a LTC?		
Desired voltage control range if LTC		
Tap adjustment time (Tap switching delay + switching time) if LTC		
Desired tap position if applicable		
Tap adjustment time (Tap switching delay + switching time)		
Impedance Z_1, X/R ratio	Z_{1H-L}	X/R
	Z_{1H-T}	X/R
	Z_{1T-L}	X/R
Impedance Z_0, X/R ratio	Z_{0H-L}	X/R
	Z_{0H-T}	X/R
	Z_{0T-L}	X/R

15. Dynamic Simulation Model for the Power Plant Controller (if applicable)

(All model files provided in section 16 should be compatible with Siemens PTI's PSS/E version

currently in use at ISO New England)

15.1 A compiled PSS/E dynamic model for the power plant controller (a *.LIB or *.OBJ file)

Attach the *.LIB or *.OBJ file and specify the name of the attachment here:

1.11 _____

15.2 A dynamic data file with appropriate parameters and settings for the power plant controller (typically a *.DYR file).

1.12 ***Please set the parameters in accordance with the currently used control mode.***

1.13 ***Attach the *.DYR file and specify the name of the attachment here:***

1.14 _____

15.3 PSS/E model user manual for the power plant controller

1.15 ***Attach the manual and specify the name of the attachment or specify the name of the attachment here:*** _____

16. Capacitors and Reactors

16 Please provide necessary modeling data for all the capacitors and reactors belong to the facility, including: size, basic electrical parameters, connecting bus, switched or fixed, etc.

17. Dynamic Device

17 ***(All model files provided in section 18 should be compatible with Siemens PTI's PSS/E version currently in use at ISO New England)***

17.1 Provide necessary modeling data file for all the dynamic devices belong to the facility.

Attach the *.LIB or *.OBJ file and specify the name of the attachment here:

18 _____

17.2 A dynamic data file containing the parameters for the units (typically a *.DYR file).

9 Set the parameters in accordance with the desired control mode.

Attach the *.DYR file and specify the name of the attachment here:

_____

18. Collection System/Transformer Tap-Setting Design

Attach a collection system/transformer tap-setting design calculations, consistent with the requirements in the ISO New England Planning Procedures, that identify the calculations to support the proposed tap settings for the unit step-up transformers and the station step-up transformers.

Attached the design document and specify the name of the attachment here:

_____

19. Additional Information

Are there any special features available to be implemented to the wind or inverter-based generating facility? Such as weak grid interconnection solutions, etc.

Specify the available features here:

_____

Insert the technical manual for each of the features listed above as objects (display as icons) or specify the name of the attachment here: _____

20. PSCAD Model and Documentation for the wind or inverter-based generating facility, the Power Plant Controller and Other Dynamic Devices for the wind or inverter-based generating facility.

ISO will determine how much PSCAD work is needed from the wind or inverter-based generating facility ***based on its interconnection system conditions.***

Attachment B (page 1)
To Appendix 1
Interconnection Request
Technical Data Required For
Interconnection Feasibility Study

The technical data required below must be submitted no later than the date of execution of the Feasibility Study Agreement pursuant to Section 6.1 of the LGIP.

LARGE GENERATING FACILITY DATA

UNIT RATING

kVA	°°F	Phase to Phase Voltage, kV
Rated Power Factor		
Speed (RPM)		Connection (e.g. Wye) _____
Short Circuit Ratio		Frequency, Hertz _____
Stator Amperes at Rated, kVA		Field Volts _____
Max Turbine MW	°°F	

GREATEST UNIT RATING AT AMBIENT TEMPERATURE OF 50°F OR ABOVE

Gross Unit Rating (MW)	Gross Lagging (MVAR)
Net Unit Rating (MW)	Gross Leading (MVAR)
Station Service (MW)	Station Service (MVAR)
Temperature (°F)	

DATA (PER UNIT-RATED KVA AND RATED VOLTAGE)

Saturated Reactance

Direct axis positive sequence X''_{dv}

negative sequence X''_{2v} _____

zero sequence X''_{0v}

Resistance

Generator AC resistance R_a _____

negative sequence R_2 _____

Attachment B (page 4)
To Appendix 1
Interconnection Request
Technical Data Required For
Interconnection Feasibility Study

For all generator types: A completed fully functioning, public (*i.e.*, non-proprietary ~~or~~, non-confidential) Siemens PTI's ("PSSE") power flow model or other compatible formats, such as IEEE and General Electric Company Power Systems Load Flow ("PSLF") data sheet, must be supplied with this Attachment B. If additional ~~non-proprietary or non-confidential~~public data sheets are more appropriate to the proposed device then they shall be provided and discussed at ~~Scoping Meeting.~~the Scoping Meeting. For all Interconnection Feasibility Studies commencing after January 1, 2017, all power flow models must be standard library models in PSS/E or applicable applications. User-models will not be accepted.

A PSCAD model shall be provided pursuant to Sections 3.3.4 and 7.2 of the LGIP for all wind and inverter-based generating facilities or if deemed required at the Scoping Meeting. A benchmarking analysis, consistent with the requirements the ISO New England Planning Procedures, confirming acceptable performance of the PSS/E model in comparison to the PSCAD model shall be provided.

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Attachment B to the Interconnection Request is true and accurate.

For Interconnection Customer:_____Date:_____

APPENDIX 2
INTERCONNECTION FEASIBILITY STUDY AGREEMENT

THIS AGREEMENT is made and entered into this _____ day of _____, 20__ by and between _____, a _____ organized and existing under the laws of the State of _____ ("Interconnection Customer,") and ISO New England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System Operator"), and _____, a _____ organized and existing under the laws of the State of _____ ("Interconnecting Transmission Owner"). Interconnection Customer, System Operator, and Interconnecting Transmission Owner may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated _____; and

WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility to the Administered Transmission System; and

WHEREAS, Interconnection Customer has requested System Operator and Interconnecting Transmission Owner to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Large Generating Facility to the Administered Transmission System, and any Affected Systems.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the Commission-approved Large Generator Interconnection Procedures ("LGIP"), or in the other provisions of the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff").

2.0 Interconnection Customer elects and System Operator shall cause to be performed an Interconnection Feasibility Study consistent with Section 6.0 of the LGIP in accordance with the Tariff.

3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection Feasibility Study shall be based on the technical information provided by Interconnection Customer in Attachment B to the Interconnection Request, as may be modified as the result of the Scoping Meeting. System Operator and Interconnecting Transmission Owner reserve the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with Section 3.3.4 of the LGIP. If, after the designation of the Point of Interconnection pursuant to Section 3.3.4 of the LGIP, Interconnection Customer modifies its Interconnection Request pursuant to Section 4.4, the time to complete the Interconnection Feasibility Study may be extended.

5.0 The Interconnection Feasibility Study report shall provide the following information depending on whether the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and short circuit analysis or limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient analysis, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Large Generating Facility's interconnection given recent study experience and as discussed at the Scoping Meeting:

- preliminary identification of any circuit breaker or other facility short circuit capability limits exceeded as a result of the interconnection, or, findings of the limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient analysis, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Large Generating Facility's interconnection given recent study experience and as discussed at the Scoping Meeting;

- preliminary identification of any thermal overload of any transmission facility or system voltage limit violations resulting from the interconnection, or, a preliminary description of and ~~, to the extent readily available to the Interconnecting Transmission Owner,~~ a non-binding good faith order of magnitude estimated cost of (unless such cost estimate is waived by the Interconnection Customer) ~~estimated cost of~~ and the time to construct the Interconnection Facilities and Network Upgrades necessary to interconnect the Large Generating Facility as identified within the scope of the analysis performed as part of the study;
- If the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and short circuit analysis, initial review of grounding requirements and electric system protection;
- If the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and short circuit analysis, preliminary description and non-binding estimated cost of and the time to construct the facilities required to interconnect the Large Generating Facility to the New England Transmission System and to address the identified short circuit and power flow issues; and
- to the extent the Interconnection Customer requested a preliminary analysis as described in this Section 6.2 of the LGIP, the report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

In accordance with the LGIP, in performing the Interconnection Feasibility Study, System Operator and Interconnecting Transmission Owner shall coordinate with each other and Affected Parties, and shall receive and incorporate input from such entities into its study, and shall provide copies of the final study report to such entities.

6.0 The Interconnection Customer is providing ~~herewith~~ a deposit equal to 100 percent of the estimated cost of the study. The deposit shall be applied toward the cost of the Interconnection Feasibility Study and the development of this Interconnection Feasibility Study Agreement and its attachment(s). Interconnecting Transmission Owner's and System Operator's good faith estimate for the time of completion of the Interconnection Feasibility Study Agreement is [insert date].

The total estimated cost of the performance of the Interconnection Feasibility Study consists of $_____ which is comprised of the System Operator's estimated cost of $_____ and the Interconnecting Transmission Owner's estimated cost of $_____. Any difference between the deposit and the actual cost of the Interconnection Feasibility Study shall be paid by or refunded to the Interconnection Customer, as appropriate. Upon receipt of the Interconnection Feasibility Study System Operator and Interconnecting Transmission Owner shall charge and the Interconnection Customer shall pay the actual costs of the Interconnection Feasibility Study.

Interconnection Customer shall pay any invoiced amounts within thirty (30) Calendar Days of receipt of the invoice.

7.0 Miscellaneous.

7.1 Accuracy of Information. Except as a Party ("Providing Party") may otherwise specify in writing when it provides information to the other Parties under this Agreement, the Providing Party represents and warrants that, to the best of its knowledge, the information it provides to the other Parties shall be accurate and complete as of the date the information is provided. The Providing Party shall promptly provide the other Parties with any additional information needed to update information previously provided.

7.2 Disclaimer of Warranty. In preparing and/or participating in the Interconnection Feasibility Study, as applicable, each Party and any subcontractor consultants employed by it shall have to rely on information provided by the Providing Party, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly, beyond the commitment to use Reasonable Efforts in preparing and/or participating in the Interconnection Feasibility Study (including, but not limited to, exercise of Good Utility Practice in verifying the accuracy of information provided for or used in the Interconnection Feasibility Study), as applicable, no Party nor any subcontractor consultant employed by it makes any warranties, express or implied, whether arising by operation of law, course of performance or dealing, custom, usage in the trade or profession, or otherwise, including without limitation implied warranties of merchantability and fitness for a particular purpose, with regard to the accuracy of the

Attachment A to
Appendix 2
Interconnection Feasibility
Study Agreement

ASSUMPTIONS USED IN CONDUCTING THE
INTERCONNECTION FEASIBILITY STUDY

The Interconnection Feasibility Study will be based upon the information set forth in the Interconnection Request and agreed upon in the Scoping Meeting held on _____:

Designation of Point of Interconnection and configuration to be studied.

Designation of alternative Point(s) of Interconnection and configuration.

[Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer, System Operator, and Interconnecting Transmission Owner]

APPENDIX 3
INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this _____ day of _____, 20__ by and between _____, a _____ organized and existing under the laws of the State of _____ ("Interconnection Customer,") and ISO New England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System Operator"), and _____, a _____ organized and existing under the laws of the State of _____ ("Interconnecting Transmission Owner"). Interconnection Customer, System Operator, and Interconnecting Transmission Owner may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated _____; and

WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility to the Administered Transmission System;

WHEREAS, System Operator and Interconnecting Transmission Owner have completed an Interconnection Feasibility Study (the "Feasibility Study") and provided the results of said study to the Interconnection Customer, or Interconnection Customer has requested that the Feasibility Study be completed as part of the System Impact Study pursuant to Section 6.1 of the LGIP, or in the other provisions of the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff")(This recital is to be omitted if Interconnection Customer has elected to forego the Interconnection Feasibility Study); and

WHEREAS, Interconnection Customer has requested System Operator and Interconnecting Transmission Owner to perform an Interconnection System Impact Study to assess the impact of interconnecting the Large Generating Facility to the Administered Transmission System, and any Affected Systems.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

- description and non-binding, good faith estimated cost of and the time to construct the facilities required to interconnect the Large Generating Facility to the Administered Transmission System and to address the identified short circuit, instability, and power flow issues; and
- to the extent the Interconnection Customer requested a preliminary analysis as described in this Section 7.4 of the LGIP, the report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

6.0 The Interconnection Customer is providing ~~herewith~~ a deposit equal to:

i. the greater of 100 percent of the estimated cost of the Interconnection System Impact Study or $250,000;
or

ii. the lower of 100 percent of the estimated cost of the Interconnection System Impact Study or $50,000, if the Interconnection Customer is providing herewith either:

(a) evidence of applications for all Major Permits, as defined in Section III.13.1.1.2.2.2(a) of the Tariff, required in support of the Interconnection Request, or provide certification that Major Permits are not required or

(b) evidence acceptable to the System Operator of At-Risk Expenditures (excluding study cots) totaling at least the amounts of money described in (i) above.

or

iii the lower of 100 percent of the estimated costs of the study or $50,000 if the Interconnection Request is for a modification to an existing Large

Generating Facility that does not increase the energy capability or capacity capability of the Large Generating Facility.

The deposit shall be applied toward the cost of the Interconnection System Impact Study and the development of this Interconnection System Impact Study Agreement and its attachment(s) and the LGIA. Interconnecting Transmission Owner's and System Operator's good faith estimate for the time of commencement and completion of the Interconnection System Impact Study is [insert date].

The total estimated cost of the performance of the Interconnection System Impact Study consists of $_____ which is comprised of the System Operator's estimated cost of $_____ and the Interconnecting Transmission Owner's estimated cost of $_____.

Any difference between the deposit and the actual cost of the Interconnection System Impact Study shall be paid by or refunded to the Interconnection Customer, as appropriate.

Upon receipt of the Interconnection System Impact Study, System Operator and Interconnecting Transmission Owner shall charge and the Interconnection Customer shall pay the actual costs of the Interconnection System Impact Study.
System Operator and Interconnecting Transmission Owner may, in the exercise of reasonable discretion, invoice the Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection System Impact Study each month. Interconnection Customer shall pay any invoiced amounts within thirty (30) Calendar Days of receipt of the invoice.

In accordance with the LGIP, in performing the Interconnection System Impact Study, System Operator and Interconnecting Transmission Owner shall coordinate with Affected Parties, shall receive and incorporate input from such entities into its study, and shall provide copies of the final study report to such entities.

7.0 Miscellaneous.

APPENDIX 4
INTERCONNECTION FACILITIES STUDY AGREEMENT

THIS AGREEMENT is made and entered into this _____ day of _____, 20__ by and between _____, a _____ organized and existing under the laws of the State of _____ ("Interconnection Customer,") and ISO New England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System Operator"), and _____, a _____ organized and existing under the laws of the State of _____ ("Interconnecting Transmission Owner"). Interconnection Customer, System Operator, and Interconnecting Transmission Owner may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated ; and

WHEREAS, Interconnection Customer desires to interconnect the Large Generating Facility to the Administered Transmission System; and

WHEREAS, System Operator and Interconnecting Transmission Owner have completed an Interconnection System Impact Study (the "System Impact Study") and provided the results of said study to the Interconnection Customer; and

WHEREAS, Interconnection Customer has requested System Operator and Interconnecting Transmission Owner to perform an Interconnection Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Large Generating Facility to the Administered Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the Commission-approved Large Generator Interconnection Procedures ("LGIP"), or in the other provisions of the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff").

2.0 Interconnection Customer elects and System Operator shall cause an Interconnection Facilities Study consistent with Section 8.0 of the LGIP to be performed in accordance with the Tariff.

3.0 The scope of the Interconnection Facilities Study shall be subject to the assumptions set forth in Attachment A and the data provided in Attachment B to this Agreement.

4.0 The Interconnection Facilities Study report (i) shall provide a description, estimated cost of (consistent with Attachment A), and schedule for required facilities to interconnect the Large Generating Facility to the Administered Transmission System and (ii) shall address the short circuit, instability, and power flow issues identified in the Interconnection System Impact Study.

5.0 The Interconnection Customer is providing ~~herewith~~ a deposit equal to:

i. the greater of 25 percent of the estimated cost of the Interconnection Facilities Study or $250,000;
or

ii. the greater of 100 percent of the estimated monthly cost of the Interconnection Facilities Study Agreement or $100,000, if the Interconnection Customer can provide either:

(a) evidence of application for all Major Permits, as defined in Section III.13.1.1.2.2.2(a) of the Tariff, required in support of the Interconnection Request, or provide certification that Major Permits are not required or

APPENDIX 5
OPTIONAL INTERCONNECTION STUDY AGREEMENT

THIS AGREEMENT is made and entered into this _____day of _____, 20___by and between _____, a _____ organized and existing under the laws of the State of _____ ("Interconnection Customer,") and ISO New England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System Operator"), and _____, a _____ organized and existing under the laws of the State of _____ ("Interconnecting Transmission Owner"). Interconnection Customer, System Operator, and Interconnecting Transmission Owner may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated _____; and

WHEREAS, Interconnection Customer is proposing to establish an interconnection to the Administered Transmission System; and

WHEREAS, Interconnection Customer has submitted to System Operator an Interconnection Request; and

WHEREAS, on or after the date when the Interconnection Customer receives the Interconnection System Impact Study results, Interconnection Customer has further requested that the System Operator and Interconnecting Transmission Owner prepare an Optional Interconnection Study.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the Commission-approved Large Generator Interconnection

Procedures ("LGIP"), or in the other provisions of the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff").

2.0 Interconnection Customer elects and System Operator shall cause an Optional Interconnection Study consistent with Section 10.0 of the LGIP to be performed in accordance with the Tariff.

3.0 The scope of the Optional Interconnection Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Optional Interconnection Study shall be performed solely for informational purposes.

5.0 The Optional Interconnection Study report shall provide a sensitivity analysis based on the assumptions specified by the Interconnection Customer in Attachment A to this Agreement. The Optional Interconnection Study will identify Interconnecting Transmission Owner's Interconnection Facilities and the Network Upgrades, and the estimated cost thereof, that may be required to provide transmission service or Interconnection Service based upon the assumptions specified by the Interconnection Customer in Attachment A.
In accordance with the LGIP, in performing the Optional Interconnection Study, the System Operator shall coordinate with Interconnecting Transmission Owner and Affected Parties, and shall receive and incorporate input from such entities into its study, and shall provide copies of the final study report to such entities.

6.0 The Interconnection Customer is providing ~~herewith~~ a deposit equal to 100 percent of the estimated cost of the study. Interconnecting Transmission Owner's and System Operator's good faith estimate for the time of completion of the Optional Interconnection Study is [insert date].

The total estimated cost of the performance of the Optional Interconnection Study consists of $_____ which is comprised of the System Operator's estimated cost of $_____ and the Interconnecting Transmission Owner's estimated cost of $_____.

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this ____ day of _____ 20__, by and between _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ ("Interconnection Customer" with a Large Generating Facility), ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("System Operator"), and _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ ("Interconnecting Transmission Owner"). Under this Agreement, the Interconnection Customer, System Operator, and Interconnecting Transmission Owner each may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, System Operator is the central dispatching agency provided for under the Transmission Operating Agreement ("TOA") which has responsibility for the operation of the New England Control Area from the System Operator control center and the administration of the Tariff; and

WHEREAS, Interconnecting Transmission Owner is the owner or possessor of an interest in the Administered Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and

WHEREAS, System Operator, Interconnection Customer and Interconnecting Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility to the Administered Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used.

ARTICLE 1. DEFINITIONS

The definitions contained in this Article 1 and those definitions embedded in an Article of this Agreement are intended to apply in the context of the generator interconnection process provided for in Schedule 22 (and its appendices). To the extent that the definitions herein are different than those contained in Section I.2.2 of the Tariff, the definitions provided below shall control only for purposes of generator interconnections under Schedule 22. Capitalized terms in Schedule 22 that are not defined in this Article 1 shall have the meanings specified in Section I.2.2 of the Tariff.

Administered Transmission System shall mean the PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Adverse System Impact shall mean any significant negative effects on the stability, reliability or operating characteristics of the electric system.

Affected Party shall mean the entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affected System shall mean any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the New England Control Area.

seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service, and in a manner that ensures intra-zonal deliverability by avoidance of the redispatch of other Capacity Network Resources or Elective Transmission Upgrades with Capacity Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Capacity Network Resource ("CNR") shall mean that portion of a Generating Facility that is interconnected to the Administered Transmission System under the Capacity Capability Interconnection Standard.

Capacity Network Resource Capability ("CNR Capability") shall mean: (i) in the case of a Generating Facility that is a New Generating Capacity Resource pursuant to Section III.13.1 of the Tariff or an Existing Generating Capacity Resource that is increasing its capability pursuant to Section III.13.1.2.2.5 of the Tariff, for Summer, the highest megawatt amount of the Capacity Supply Obligation obtained by the Generating Facility in accordance with Section III.13 of the Tariff, and, if applicable, as specified in a filing by the System Operator with the Commission in accordance with Section III.13.8.2 of the Tariff, net of any megawatt amount reductions resulting from terminations, retirements or permanent de-list bids in accordance with Section III.13 of the Tariff, and, for Winter, ~~shall be~~ the Summer CNR Capability multiplied by the ratio of the associated Winter Qualified Capacity divided by the associated Summer Qualified Capacity, or (ii) in the case of a Generating Facility that meets the criteria under Section 5.2.3 of this LGIP, the total megawatt amount determined pursuant to the hierarchy established in Section 5.2.3~~.~~, net of any megawatt amount reductions resulting from terminations, retirements or permanent de-list bids in accordance with Section III.13 of the Tariff. CNR Capability shall not exceed the maximum net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90 degrees F for Summer and at or above 20 degrees F for Winter. Where the Generating Facility includes multiple production devices, the CNR Capability shall not exceed the aggregate maximum net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90 degrees F for Summer and at or above 20 degrees F for Winter.

Capacity Network Resource Group Study ("CNR Group Study") shall mean the study performed by the System Operator under Section III.13.1.1.2.3 of the Tariff to determine which resources qualify to participate in a Forward Capacity Auction.

facilities, and the time required to interconnect the Generating Facility with the Administered Transmission System. The scope of the study is defined in Section 8 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Administered Transmission System, the scope of which is described in Section 6 of the Standard Large Generator Interconnection Procedures. The Interconnection Customer has the option to request either that the Interconnection Feasibility Study be completed as a separate and distinct study, or as part of the Interconnection System Impact Study. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 6 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 6 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 6 and Section 7.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request (a) shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to: (i) interconnect a new Generating Facility to the Administered Transmission System as either a CNR or a NR; (ii) make a Material Modification to a proposed Generating Facility with an outstanding Interconnection Request; (iii) increase the energy capability or capacity capability of an existing Generating Facility; (~~iii~~iv) make a Material Modification to the design or operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected with the Administered Transmission System; (~~iv~~v) commence participation in the wholesale markets by an existing Generating Facility that is interconnected with the Administered Transmission System; or (~~v~~vi)

material impact (*i.e.*, an evaluation of the proposed modification cannot be completed in less than ten (10) Business Days) on the cost or timing of any Interconnection Studies or upgrades associated with an Interconnection Request with a later queue priority date; (ii) a change to the design or operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected with the Administered Transmission System that may have a significant adverse effect on the reliability or operating characteristics of the New England Transmission System; (iii) a delay to the Commercial Operation Date, In-Service Date, or Initial Synchronization Date of greater than three (3) years where the reason for delay is unrelated to construction schedules or permitting which delay is beyond the Interconnection Customer's control; or (iv) except as provided in Section 3.2.3.4 of the LGIP, a withdrawal of a request for Long Lead Facility treatment; or (v) except as provided in Section 3.2.3.6 of the LGIP, an election to participate in an earlier Forward Capacity Auction than originally anticipated.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

Network Capability Interconnection Standard ("NC Interconnection Standard") shall mean the minimum criteria required to permit the Interconnection Customer to interconnect a Generating Facility seeking Network Resource Interconnection Service or Elective Transmission Upgrade seeking Network Import Interconnection Service in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility seeking Network Resource Interconnection Service or Elective Transmission Upgrade seeking Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Network Resource ("NR") shall mean the portion of a Generating Facility that is interconnected to the Administered Transmission System under the Network Capability Interconnection Standard.

Network Resource Capability ("NR Capability") shall mean the maximum gross and net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 50 degrees F for Summer and at or above 0 degrees F for Winter. Where the Generating Facility includes multiple energy production devices, the NR Capability shall be the aggregate maximum gross and net megawatt electrical output of the Generating Facility at the Point of

property for which new interconnection is sought; or (e) that the Interconnection Customer has filed applications for required permits to site on federal or state property.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The System Operator, Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by System Operator in accordance with applicable codes of conduct and confidentiality requirements, must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement ("LGIA") shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility, that is included in this Schedule 22 to the Tariff.

Standard Large Generator Interconnection Procedures ("LGIP") shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in this Schedule 22 to the Tariff.

Study Case shall have the meaning specified in Sections 6.2 and 7.3 of this LGIP.

System Protection Facilities shall mean the equipment, including necessary signal protection communications equipment, required to protect (1) the New England Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the New England Transmission System or on other delivery systems or other generating systems to which the New England Transmission System is directly connected.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

ARTICLE 2. EFFECTIVE DATE, TERM AND TERMINATION

information so provided be subject to the confidentiality provisions of Article 22. If the Interconnection Customer has executed this LGIA, or any amendment thereto, the Interconnection Customer shall reasonably cooperate with the System Operator and Interconnecting Transmission Owner with respect to such filing and to provide any information reasonably requested by the System Operator and/or the Interconnecting Transmission Owner needed to comply with applicable regulatory requirements.

ARTICLE 4. SCOPE OF SERVICE

4.1 Interconnection Product Options. Interconnection Customer has selected the following (checked) type(s) of Interconnection Service:

Check: ___ NR for NR Interconnection Service (NR Capability Only)

___ CNR for CNR Interconnection Service (CNR Capability and NR Capability)

4.1.1 Capacity Network Resource Interconnection Service (CNR Interconnection Service).

4.1.1.1 The Product. The System Operator and Interconnecting Transmission Owner must conduct the necessary studies and the Interconnecting Transmission Owner and Affected Parties must construct the Network Upgrades needed to interconnect the Large Generating Facility in a manner comparable to that in which all other Capacity Network Resources are interconnected under the ~~CNR~~CC Interconnection Standard. CNR Interconnection Service allows the Interconnection Customer's Large Generating Facility to be designated as a Capacity Network Resource, to participate in the New England Markets, in accordance with Market Rule 1, Section III of the Tariff, up to the net CNR Capability, or as otherwise provided in Market Rule 1, Section III of the Tariff, on the same basis as all other existing Capacity Network Resources, and to be studied as a Capacity Network Resource on the assumption that such a designation will occur.

4.1.2 Network Resource Interconnection Service (NR Interconnection Service).

4.1.2.1 The Product. The System Operator and Interconnecting Transmission Owner must conduct the necessary studies and Interconnecting Transmission Owner and Affected Parties must construct the Network Upgrades needed to interconnect the Large Generating Facility in a manner comparable to that in which all other Network Resources are interconnected under the NC Interconnection Standard. ~~NC~~NR Interconnection Service allows the Interconnection Customer's Large Generating Facility to participate in the New England Markets, in accordance with Market Rule 1, Section III of the Tariff, up to the gross and net NR Capability or as otherwise provided in Market Rule l, Section III of the Tariff. Notwithstanding the above, the portion of a Large Generating Facility that has been designated as a Network Resource interconnected under the NC Interconnection Standard cannot be a capacity resource under Section III.13 of the Tariff, unless pursuant to a new Interconnection Request for CNR Interconnection Service.

4.2 Provision of Service. System Operator and Interconnecting Transmission Owner shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 Performance Standards. Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such requirements and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is the Interconnecting Transmission Owner, then that Party shall amend the LGIA and System Operator, in conjunction with the Interconnecting Transmission Owner, shall submit the amendment to the Commission for approval.

4.4 No Transmission Delivery Service. The execution of this LGIA does not constitute a request for, nor the provision of, any service except for Interconnection Service, including, but not limited to, transmission delivery service, local delivery service, distribution service, capacity service, energy service, or Ancillary Services under any applicable tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

Interconnection Facilities and Network Upgrades, the Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Interconnecting Transmission Owner, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 Contests. In the event any Governmental Authority determines that Interconnecting Transmission Owner's receipt of payments or property constitutes income that is subject to taxation, Interconnecting Transmission Owner shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Interconnecting Transmission Owner may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Interconnecting Transmission Owner may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Interconnecting Transmission Owner reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Interconnecting Transmission Owner shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Interconnecting Transmission Owner on a periodic basis, as invoiced by Interconnecting Transmission Owner, documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Interconnecting Transmission Owner may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Interconnecting Transmission Owner, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally recognized tax counsel selected under the terms of the

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA and ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.5 Start-Up and Synchronization. The Interconnection Customer is responsible for the proper start-up and synchronization of the Large Generating Facility to the New England Transmission System in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.6 Reactive Power.

9.6.1 Power Factor Design Criteria. Interconnection Customer shall design the Large Generating Facility and all generating units comprising the Large Generating Facility, as applicable, to maintain a composite power delivery at continuous rated power output at the Point of Interconnection ~~at a~~with dynamic reactive capability over the power factor ~~within the~~ range of 0.95 leading to 0.95 lagging, unless the System Operator or Interconnecting Transmission Owner has established different requirements that apply to all generators in the Control Area on a comparable basis and in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The requirements of this paragraph shall not apply to wind generators. The power factor design criteria requirements applicable to wind Generating Facilities shall be as specified in in Appendix G to the LGIP. The Low Voltage Ride-Through Capability requirements applicable to wind and inverter-based Generating Facilities shall be as specified in Appendix G to the LGIP.

9.6.2 Voltage Schedules. Once the Interconnection Customer has synchronized the Large Generating Facility to the New England Transmission System, Interconnection Customer shall operate the Large Generating Facility at the direction of System Operator and Interconnecting Transmission Owner in accordance with applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, regarding voltage schedules in accordance with such requirements.

the pro rata use of the Interconnection Facilities by Interconnecting Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed-upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Interconnecting Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed-upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to the Commission for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or the New England Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 10. MAINTENANCE

10.1 Interconnecting Transmission Owner and Customer Obligations. Interconnecting Transmission Owner and Interconnection Customer shall each maintain that portion of its respective facilities that are part of the New England Transmission System and the Interconnecting Transmission Owner's Interconnection Facilities in a safe and reliable manner and in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

10.2 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation,

APPENDIX A TO LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

1. Interconnection Facilities:

a. **Point of Interconnection and Point of Change of Ownership**. The Point of Interconnection shall be at the point where [*insert description of location*]. See Appendix A-[*insert*], which drawing is attached hereto and made part hereof.

The Point of Change of Ownership shall be at the point where *[insert description of location]*. See Appendix A – [*insert*], which drawing is attached hereto and made part hereof.

If not located at the Point of Interconnection, the metering point(s) shall be located at: [*insert location*].

b. **Interconnection Customer's Interconnection Facilities (including metering equipment)**. The Interconnection Customer shall construct [*insert Interconnection Customer's Interconnection Facilities*]. See Appendix A-[*insert*].

c. **Interconnecting Transmission Owner's Interconnection Facilities (including metering equipment)**. The Interconnecting Transmission Owner shall construct [*insert Interconnecting Transmission Owner's Interconnection Facilities*]. See Appendix – [*insert*].

2. Network Upgrades:

a. **Stand Alone Network Upgrades**. [*insert Stand Alone Network Upgrades*].

b. **Other Network Upgrades**. [*insert Other Network Upgrades*].

3. Distribution Upgrades. [*insert Distribution Upgrades*]

4. Affected System Upgrades. [insert Affected System Upgrades]

5. Contingency Upgrades List:

a. Long Lead Facility-Related Upgrades. The Interconnection Customer's Large Generating Facility is associated with a Long Lead Facility, in accordance with Section 3.2.3 of the LGIP. Pursuant to Section 4.1 of the LGIP, the Interconnection Customer shall be responsible for the following upgrades in the event that the Long Lead Facility achieves Commercial Operation and obtains a Capacity Supply Obligation in accordance with Section III.13.1 of the Tariff:

[*insert list of upgrades*]

If the Interconnection Customer fails to cause these upgrades to be in-service prior to the commencement of the Long Lead Facility's Capacity Commitment Period, the Interconnection Customer shall be deemed to be in Breach of this LGIA in accordance with Article 17.1, and the System Operator will initiate all necessary steps to terminate this LGIA, in accordance with Article 2.3.

b. Other Contingency Upgrades. [*e.g*., list of upgrades associated with higher queued Interconnection Requests with LGIAs prior to this LGIA and any other contingency upgrades that the Parties may deem necessary for the interconnection of the Large Generating Facility.]

6. Post-Forward Capacity Auction Re-study Upgrade Obligations. [*insert any change in upgrade obligations that result from re-study conducted post receiving a Capacity Supply Obligation through a Forward Capacity Auction.*]

APPENDIX C TO LGIA

Interconnection Details

1. Description of Interconnection:

Interconnection Customer shall install a [*insert*] MW facility, rated at [*insert*]MW gross and [*insert*] MW net, with all studies performed at or below these outputs. The Generating Facility is comprised of [*insert*] units in a [*insert description of facility type - combined cycle, wind farm, etc.*] rated at: [*insert*] MW each, and will located at [*insert location*].

The Large Generating Facility shall receive:

Network Resource Interconnection Service for the NR Capability at a level not to exceed [*insert gross and net*] MW for Summer, and [*insert gross and net*] MW for Winter.

Capacity Network Resource Interconnection Service for: (i) the NR Capability at a level not to exceed [*insert gross and net at or above 50 degrees F*] MW for Summer and [*insert gross and net at or above 0 degrees F*] MW for Winter; and (ii) the CNR Capability at [*insert net*] MW for Summer and [*insert net*] MW for Winter, which shall not exceed [*insert the maximum net MW electrical output of the Generating Facility at an ambient temperature at or above 90 degrees F for summer and at or above 20 degrees F for winter*.] ~~The CNR Capability shall be the highest amount of the Capacity Supply Obligation obtained by the Generating Facility in accordance with Section III.13 of the Tariff and, if applicable, as specified in filings by the System Operator with the Commission pursuant to Section III.13 of the Tariff.~~

2. Detailed Description of Generating Facility and Generator Step-Up Transformer, if applicable:

Generator Data	
Number of Generators	
Manufacturer	
Model	

APPENDIX E TO LGIA

Commercial Operation Date

This Appendix E is a part of the LGIA between System Operator Interconnecting, Transmission Owner and Interconnection Customer.

[*Date*]

[*Interconnecting Transmission Owner; Address*]
[to be supplied]

Generator Interconnections
Transmission Planning Department
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Re: _____ Large Generating Facility

Dear _____:

On [Date] [Interconnection Customer] has completed Trial Operation of Unit No. ___. This letter confirms that [Interconnection Customer] commenced commercial operation of Unit No. ___ at the Large Generating Facility, effective as of [Date plus one day].

Thank you.

[*Signature*]
[*Interconnection Customer Representative*]

APPENDIX G TO LGIA

Interconnection Requirements For A Wind and Inverter-Based Generating ~~Plant~~Facilities

Appendix G sets forth requirements and provisions specific to ~~a~~ wind ~~generating plant~~and inverter-based Generating Facilities. All other requirements of this LGIA continue to apply to wind ~~generating plant~~and inverter-based Generating Facility interconnections.

A. Technical Standards Applicable to ~~a~~ Wind and Inverter-Based Generating ~~Plant~~Facility

i. Low Voltage Ride-Through (LVRT) Capability

~~A wind generating plant~~Wind and inverter-based Generating Facilities shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the System Operator and Interconnecting Transmission Owner. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind

generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or "GSU"), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual wind generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT. Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual wind generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind ~~generating plants~~Generating Facilities subject to FERC Order No. 661 and not covered by the transition period described above~~ must~~, as well as inverter-based Generating Facilities must meet the following requirements:

1. Wind ~~generating plants~~and inverter-based Generating Facilities are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind ~~generating plant~~or inverter-based

Generating Facility substation location, as determined by and documented by the System Operator and Interconnecting Transmission Owner. The maximum clearing time the wind ~~generating plant~~or inverter-based Generating Facility shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind ~~generating plant~~or inverter-based Generating Facility may disconnect from the transmission system. ~~A wind generating plant~~Wind and inverter-based Generating Facilities shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind ~~GSU.~~or inverter-based Generating Facility GSU.

2. This requirement does not apply to faults that would occur between the wind ~~generator~~or inverter-based Generating Facility terminals and the high side of the GSU.

3. Wind ~~generating plants~~and inverter-based Generating Facilities may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind ~~generating plants~~and inverter-based Generating Facilities may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind ~~generating plant~~or inverter~~ed~~-based Generating Facility or by a combination of generator performance and additional equipment.

5. Existing individual wind generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual wind generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. Power Factor Design Criteria (Reactive Power)

1. ~~A wind generating plant~~A wind Generating Facility for which the Interconnection System Impact Study commences after [effective date] shall maintain dynamic reactive capability over the power factor range of 0.95 leading to 0.95 lagging, at continuous rated power output, measured at the high-side of

the station transformer or at the Point of the Interconnection if there is no station transformer.

2. A wind Generating Facility for which the Interconnection System Impact Study commences before [effective date] shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Interconnection System Impact Study shows that such a requirement is necessary to ensure safety or reliability. ~~The~~For a wind Generating Facility for which the Interconnection System Impact Study commences before [effective date], the power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the System Operator and Interconnecting Transmission Owner, or a combination of the two.
3. The Interconnection Customer shall not disable power factor equipment while the wind ~~generating plant~~Generating Facility is in operation.
4. Wind ~~generating plants~~Generating Facility shall also be able to provide sufficient additional dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Interconnection System Impact Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

~~The wind generating plant~~Wind and inverter-based Generating Facilities shall provide SCADA capability to transmit data and receive instructions from the System Operator and Local Control Center to protect system reliability. The System Operator, Interconnecting Transmission Owner and the wind ~~generating plant~~or inverter-based Generating Facility Interconnection Customer shall determine what SCADA information is essential for the proposed wind ~~generating plant~~or inverter-based Generating Facility, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Draft Revisions
New Interconnection Requirements Project

January 26, 2016 TC Meeting (FOR VOTE)

As Voted by the TC

SCHEDULE 23

SMALL GENERATOR INTERCONNECTION PROCEDURES

1.2.4 The pre-application report need only include existing data. A pre-application report request does not obligate the System Operator or the Interconnecting Transmission Owner to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the System Operator in conjunction with the Interconnecting Transmission Owner cannot complete all or some of a pre-application report due to lack of available data, the System Operator in conjunction with the Interconnecting Transmission Owner shall provide the Interconnection Customer with a pre-application report that includes the data that is available. The provision of information on "available capacity" pursuant to section 1.2.3.4 does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the pre-application report may become outdated at the time of the submission of the complete Interconnection Request. Notwithstanding any of the provisions of this section, the System Operator in conjunction with the Interconnecting Transmission Owner shall, in good faith, include data in the pre-application report that represents the best available information at the time of reporting.

1.3 Interconnection Request

To initiate an Interconnection Request, the Interconnection Customer shall submit to the System Operator its completed Interconnection Request ~~to the System Operator~~in the form of Attachment 2 to this SGIP, together with the processing fee or deposit specified in the Interconnection Request. The Interconnection Request shall be submitted to the System Operator in the manner specified in Attachment 2. The Interconnection Request shall be date- and time-stamped upon receipt. The original date- and time-stamp applied to the Interconnection Request at the time of its original submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in these procedures. The Interconnection Customer shall be notified of receipt by the System Operator within three (3) Business Days of receiving the Interconnection Request. The System Operator shall notify the Interconnection Customer within ten (10) Business Days of the receipt of the Interconnection Request as to whether the Interconnection Request is complete or incomplete. If the Interconnection Request is incomplete, the System Operator shall provide along with the notice that the Interconnection Request is incomplete, a written list detailing all information that must be provided to complete the Interconnection Request. The Interconnection Customer will have ten (10) Business Days after receipt of the notice to submit the listed information or to request an extension of time to provide such information. If the Interconnection Customer does not provide the listed information or a request for an extension of time within the deadline, the Interconnection Request will be deemed withdrawn. An Interconnection Request will be deemed complete upon submission of the listed information to the System Operator.

The Interconnection Customer must submit a separate Interconnection Request for each site. The Interconnection Customer must comply with the requirements specified in this Section 1.3 for each Interconnection Request even when more than one request is submitted for a single site.

1.3.1 Within three (3) Business Days of receiving the Interconnection Request, the System Operator shall provide a copy of the Interconnection Request to the Interconnecting Transmission Owner. The System Operator, in consultation with the Interconnecting Transmission Owner, shall determine whether the Interconnection Request is complete or incomplete. If such request is to interconnect to a distribution facility, the Interconnecting Transmission Owner shall be responsible for determining whether the distribution facility is subject to the Tariff.

1.3.2 All fees or deposits that must be submitted to the System Operator under this SGIP, must be delivered to the System Operator by electronic transfer within the period specified in the respective provision.

1.4 Site Control

Documentation of site control must be submitted with the Interconnection Request. Interconnection Customer does not need to demonstrate Site Control where the Interconnection Request is for a modification to the Interconnection Customer's existing Small Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the modification proposed in the Interconnection Request does not require additional real property. Site control may be demonstrated through:

1.4.1 Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Small Generating Facility;

1.4.2 An option to purchase or acquire an easement, a license or a leasehold interest in the site for such purpose; or

1.4.3 An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose; or

Interconnection Request for CNR Interconnection Service will be required for the Generating Facility to participate in any subsequent auctions.

1.6 Procedures for Transition

1.6.1 **Queue Position for Pending Requests.** Any Interconnection Customer assigned a Queue Position prior to ~~February 1, 2009~~[Effective Date] shall retain that Queue Position subject to Section 1.6 of the SGIP.

1.6.1.1 If an Interconnection Study Agreement has not been executed prior to ~~February 1, 2009,~~[Effective Date], then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with the version of this SGIP in effect on ~~February 1, 2009~~[Effective Date] (or as revised thereafter).

1.6.1.2 If an Interconnection Study Agreement has been executed prior to ~~February 1, 2009,~~[Effective Date], such Interconnection Study shall be completed in accordance with the terms of such agreement. If an Interconnection Study Ageement has been executed prior to [Effective Date], but the Interconection Study has not commenced, such Interconnection Study shall be completed, and any subsequent Interconnection Studies shall be processed, in accordance with the version of the SGIP in effect on [Effective Date]. If the Interconnection Study has not commenced, within sixty (60) Calendar Days from ~~the~~ [Effective Date], Interconnection Customer shall submit an updated Interconnection Request, together with completed attachments and models required therein to facilitate the System Operator, in coordination with Interconnecting Transmission Owner and Affected Party as deemed appropriate by the System Operator, conduct of the Interconnection Study. Updates to the Interconnection Request and attachments thereto will be subject to review pursuant to Section 1.5.4 of this SGIP. Notwithstanding any other provision in this SGIP, if the Interconnection Customer fails to meet these requirements within a period not to exceed sixty (60) Calendar Days, the Interconnection Request shall be deemed withdrawn.

1.6.2 **Transition Period**. To the extent necessary, the System Operator, Interconnection Customers with an outstanding Interconnection Request (i.e., an Interconnection Request for which an SGIA has neither been executed nor submitted to the Commission for approval prior to ~~February 1, 2009),~~[Effective Date]), Interconnecting Transmission Owner and any other Affected Parties, shall transition to proceeding under the version of the SGIP in effect as of ~~February 1, 2009~~[Effective Date] (or as revised thereafter) within a

reasonable period of time not to exceed sixty (60) Calendar Days. The use of the term "outstanding Interconnection Request" herein shall mean any Interconnection Request, on ~~February 1, 2009:~~[Effective Date]: (i) that has been submitted, together with the required deposit and attachments, but not yet accepted by the System Operator; (ii) where the related SGIA has not yet been submitted to the Commission for approval in executed or unexecuted form, (iii) where the relevant Interconnection Study Agreements have not yet been executed, or (iv) where any of the relevant Interconnection Studies are in process but not yet completed. Any Interconnection Customer with an outstanding ~~request~~Interconnection Request as of the effective date of this SGIP may request a reasonable extension of ~~any deadline, otherwise~~the next applicable~~,~~ deadline if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension shall be granted by the System Operator to the extent consistent with the intent and process provided for under this SGIP.

1.6.3 **One-Time Election for CNR Interconnection Service at Queue Position Assigned Prior to February 1, 2009**. An Interconnection Customer with an outstanding Interconnection Request will be eligible to make a one-time election to be considered for CNR Interconnection Service at the Queue Position assigned prior to February 1, 2009. The Interconnection Customer's one-time election must be made by the end of the New Generating Capacity Show of Interest Submission Window for the fourth Forward Capacity Auction. Interconnection Customers requesting CNR Interconnection Service will be required to comply with the requirements for CNR Interconnection Service set forth in Section 1.7.1. Interconnection Customers requesting CNR Interconnection Service that have not received a completed Interconnection System Impact Study may request a preliminary, non-binding, analysis of potential upgrades that may be necessary for the fourth Forward Capacity Auction – the prompt or near-term auction – pursuant to Sections 3.3.2 or 3.4.3, whichever is applicable.

1.6.4 **Grandfathering.**

1.6.4.1 An Interconnection Customer's Generating Facility that is interconnected pursuant to an Interconnection Agreement executed or submitted to the Commission for approval prior to February 1, 2009, will maintain its status as a Network Resource with Network Resource Interconnection Service eligible to participate in the New England Markets, in accordance with the requirements of Market Rule 1, Section III of the Tariff, up to the megawatt amount specified in the Interconnection Agreement, subject to the Interconnection Customer satisfying all requirements set forth in the Interconnection Agreement and this SGIP. If the Generating Facility does not meet the criteria set forth in Section 1.6.4.3

1. For purposes of this table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

2. An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report pursuant to section 1.2.

2.2 Initial Review

Within fifteen (15) Business Days after the System Operator notifies the Interconnection Customer it has received a complete Interconnection Request, the System Operator in conjunction with the Interconnecting Transmission Owner shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the determinations under the screens.

2.2.1 Screens

2.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Interconnecting Transmission Owner's Distribution System that is subject to the Tariff.

2.2.1.2 For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation. A line section is that portion of an Interconnecting Transmission Owner's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

2.2.1.3 For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5 % of a spot network's maximum load or 50 kW.

2.2.1.4 The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

necessary to facilitate the administration of the Interconnection Procedures. A PSCAD model is required for all wind and inverter-based Small Generating Facilities. If a PSCAD model is required for other Small Generating Facility~~ies~~ types, the Parties shall discuss this at the Scoping Meeting. The Parties shall discuss whether the System Operator should perform an Interconnection Feasibility Study or proceed directly to an Interconnection System Impact Study, or an Interconnection Facilities Study, or an SGIA. If the Interconnection Customer provides the technical data called for in Attachment 2 to this SGIP with the Interconnection Request, the Parties shall discuss the detailed project design at the Scoping Meeting. Within five (5) Business Days following the scoping meeting, the Interconnection Customer shall notify the System Operator, in writing: (i) whether it wants the Interconnection Feasibility Study to be completed, as a separate and distinct study or as part of the Interconnection System Impact Study, (ii) if requesting the Interconnection Feasibility Study be completed as a separate and distinct study, which of the alternative study scopes is being selected pursuant to Section 3.3.2, and (iii) the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection for inclusion in the attachment to the Interconnection Feasibility Study Agreement (Attachment 6), or the Interconnection System Impact Study Agreement (Attachment 7) if the Interconnection Customer elects not to pursue the Interconnection Feasibility Study.

3.2.3 The scoping meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an Interconnection Customer who has requested an Interconnection Feasibility Study must return the executed Interconnection Feasibility Study Agreement (or Interconnection System Impact Study Agreement if the Interconnection Customer elected not to pursue the Interconnection Feasibility Study), within fifteen (15) Business Days.

3.3 Interconnection Feasibility Study

3.3.1 **Interconnection Feasibility Study Agreement**. Within five (5) Business Days following the Interconnection Customer's request for an Interconnection Feasibility Study, the System Operator shall tender to Interconnection Customer the Interconnection Feasibility Study Agreement signed by the System Operator and Interconnecting Transmission Owner, including an outline of the scope of the Interconnection Feasibility Study and a non-binding good faith estimate of the cost to perform the Interconnection Feasibility Study. The Interconnection Feasibility Study Agreement shall specify that Interconnection Customer is responsible for the actual cost of the Interconnection Feasibility Study, including the cost of developing the study agreement and its attachment(s). No later than fifteen (15)

Business Days after its receipt of the Interconnection Feasibility Study Agreement, the Interconnection Customer shall execute and deliver the agreement, including completed attachments, to System Operator and the Interconnecting Transmission Owner, together with the refundable deposit of the lesser of 50 percent of the good faith estimated Interconnection Feasibility Study costs or earnest money of $1,000. The deposit shall be applied toward the cost of the Interconnection Feasibility Study, including the cost of developing the study agreement and its attachment(s). Any difference between the study deposit and the actual cost of the Interconnection Feasibility Study shall be paid by or refunded to the Interconnection Customer. The System Operator and/or Interconnecting Transmission Owner shall issue to the Interconnection Customer an invoice for the costs of the Interconnection Feasibility Study that have been incurred by the System Operator and/or the Interconnecting Transmission Owner on the Interconnection Feasibility Study, including the development of the study agreement and its attachment(s). The System Operator and the Interconnecting Transmission Owner may, in the exercise of reasonable discretion, invoice the Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection Feasibility Study on each month. The Interconnection Customer shall pay the invoiced amounts, to the extent such amounts are greater than the initial deposit, within thirty (30) Calendar Days of receipt of invoice. System Operator shall continue to hold any amounts on deposits until settlement of the final invoice with the Interconnection Customer and the Interconnecting Transmission Owner.

3.3.2 **Scope of Interconnection Feasibility Study**. The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the Administered Transmission System with available data and information. ~~The Interconnection Feasibility Study does not require detailed model development.~~ The Interconnection Feasibility Study will consider the Base Cases as well as all generating facilities and Elective Transmission Upgrades (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request; and (iv) have no Queue Position but have executed an Interconnection Agreement or requested that an unexecuted Interconnection Agreement be filed with the Commission~~.~~ (the "Study Case" for the Interconnection Feasibility Study). An Interconnection Customer with a CNR Interconnection Request may also request that the Interconnection Feasibility Study include a preliminary, non-binding, analysis to identify potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity

Auction under Section III.13 of the Tariff, based on a limited set of assumptions to be specified by the Interconnection Customer and reflected in Attachment A to the Interconnection Feasibility Study Agreement. The Interconnection Feasibility Study will consist of a power flow, including thermal analysis and voltage analysis, and short circuit analysis. The Interconnection Feasibility Study report will provide (i) a list of facilities and a non-binding good faith estimate of cost responsibility; (ii) a non-binding good faith estimated time to construct the Interconnection Facilities and Network Upgrades; (iii) a protection assessment to determine the required Interconnection Facilities; and may provide (iv) an evaluation of the siting of Interconnection Facilities and Network Upgrades; and (v) identification of the likely permitting and siting process including easements and environmental work for Interconnection Facilities and Network Upgrades.

Alternatively, in the case where the Interconnection Customer requests that the Interconnection Feasibility Study be completed as a separate and distinct study, the Interconnection Customer may provide the technical data called for in Appendix 1, Attachment A with the executed Interconnection Feasibility Study Agreement and request that the Interconnection Feasibility Study consist of limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient analysis, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Small Generating Facility's interconnection given recent study experience and as discussed at the Scoping Meeting. In this case, the Interconnection Feasibility Study report will provide (i) the study findings; and, (ii) a preliminary description of and~~, to the extent readily available to the Interconnecting Transmission Owner,~~ a non-binding good faith order of magnitude estimated cost of (unless such cost estimate is waived by the Interconnection Customer)~~estimated cost of~~ and the time to construct the Interconnection Facilities and Network Upgrades necessary to interconnect the Small Generating Facility as identified within the scope of the analysis performed as part of the study.

To the extent the Interconnection Customer requested a preliminary analysis as described in this Section 3.3, the Interconnection Feasibility Study report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

3.3.3 **Interconnection Feasibility Study Procedures**. The System Operator in coordination with Interconnecting Transmission Owner shall utilize existing studies to the extent practicable when it performs the study. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the Interconnection Feasibility Study no later than thirty (30) Business Days after System Operator and Interconnecting Transmission Owner receive the fully executed Interconnection

Facility receives a Capacity Supply Obligation in accordance with Section III.13 of the Tariff, or (iv) a modification to a transmission project included in the Base Case, the System Operator shall notify the Interconnection Customer and Interconnecting Transmission Owner in writing. Each re-study shall be conducted serially based on the Queue Position of each Interconnection Customer, and each re-study shall take not longer than thirty (30) Business Days from the date the re-study commences. Any cost of re-study shall be borne by the Interconnection Customer being re-studied. If the original Interconnection Feasibility Study is complete and the final invoice has been issued, the re-study shall be performed under a new Interconnection Feasibility Study Agreement. The Interconnection Customer shall have the option to waive the re-study and elect to have the re-study performed as part of its Interconnection System Impact Study. The Interconnection Customer shall provide written notice of the waiver and election of moving directly to the Interconnection System Impact Study within five (5) Business Days of receiving notice from the System Operator of the required re-study.

3.4 Interconnection System Impact Study

3.4.1 **Interconnection System Impact Study Agreement**. Within five (5) Business Days following the Interconnection Feasibility Study results meeting, the System Operator and Interconnecting Transmission Owner shall provide to Interconnection Customer the Interconnection System Impact Study Agreement, which includes a non-binding good faith estimate of the cost and timeframe to perform the Interconnection System Impact Study. The Interconnection System Impact Study Agreement shall provide that the Interconnection Customer shall compensate the System Operator and Interconnecting Transmission Owner for the actual cost of the Interconnection System Impact Study, including the cost of developing the study agreement and its attachment(s) and the cost of developing the SGIA.

3.4.2 **Execution of Interconnection System Impact Study Agreement.** The Interconnection Customer shall execute the Interconnection System Impact Study Agreement and deliver the executed Interconnection System Impact Study Agreement, including completed attachments, to the System Operator no later than fifteen (15) Business Days after its receipt along with (1) demonstration of Site Control, (2) a refundable deposit of 50 percent of the good faith estimated cost for the transmission portion of the Interconnection System Impact Study and 100 percent of the good faith estimated cost for the distribution portion of the Interconnection System Impact Study, and (3) a PSCAD model if one was determined to be needed for the non-wind or non-inverter-based Small Generating Facility at the Scoping Meeting; provided that if a PSCAD model was determined to be needed at the Scoping Meeting, then the

Interconnection Customer shall have ninety (90) Calendar Days from the date of the Scoping Meeting or the execution of the System Impact Study Agreement (whichever is later) to provide the PSCAD model. Interconnection Customer does not need to demonstrate Site Control where the Interconnection Request is for a modification to the Interconnection Customer's existing Small Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the modification proposed in the Interconnection Request does not require additional real property. The deposit shall be applied toward the cost of the Interconnection System Impact Study, including the cost of developing the study agreement and its attachment(s) and the cost of developing the SGIA. Any difference between the study deposit and the actual cost of the Interconnection System Impact Study shall be paid by or refunded to the Interconnection Customer. The System Operator and/or the Interconnecting Transmission Owner shall issue to the Interconnection Customer an invoice for the costs of Interconnection System Impact Study that have been incurred by the System Operator and/or the Interconnecting Transmission Owner for the System Impact Study, including the study agreement and its attachment(s) and the SGIA.

The System Operator and the Interconnecting Transmission Owner may, in the exercise of reasonable discretion, invoice the Interconnection Customer on a monthly basis for the work to be conducted on the transmission portion of the Interconnection System Impact Study on each month. The Interconnection Customer shall pay the invoiced amounts, to the extent such amounts are greater than the initial deposit, within thirty (30) Calendar Days of receipt of invoice. The System Operator shall continue to hold the amounts on deposit until settlement of the final invoice with the Interconnection Customer and the Interconnecting Transmission Owner.

3.4.3 **Scope of Interconnection System Impact Study**. The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability and operation of the New England Transmission System. The Interconnection System Impact Study will consider the Base Case as well as all generating facilities and Elective Transmission Upgrades (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request; and (iv) have no Queue Position but have executed an Interconnection Agreement or requested that an

unexecuted Interconnection Agreement be filed with the Commission. (the "Study Case" for the Interconnection System Impact Study). An Interconnection Customer with a CNR Interconnection Request that elected to waive the Interconnection Feasibility Study may also request that the Interconnection System Impact Study include a preliminary, non-binding, analysis to identify potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff, based on a limited set of assumptions to be specified by the Interconnection Customer and reflected in Attachment A to the Interconnection System Impact Study Agreement. The Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, a power flow analysis, including thermal analysis and voltage analysis, a system protection analysis and any other analyses, such as electromagnetic transient analysis, that are deemed necessary by the System Operator in consultation with the Interconnecting Transmission Owner. The Interconnection System Impact Study report will state the assumptions upon which it is based, state the results of the analyses, and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Interconnection System Impact Study report will provide (i) a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility, (ii) a non-binding good faith estimated time to construct, (iii) a protection assessment to determine the required protection upgrades; and may provide (iv) an evaluation of the siting of the Interconnection Facilities and Network Upgrades; and (v) identification of the likely permitting and siting process including easements and environmental work. To the extent the Interconnection Customer requested a preliminary analysis as described in this Section 3.4.3, the Interconnection System Impact Study report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

3.4.4 **Interconnection System Impact Study Procedures.** The System Operator shall coordinate the Interconnection System Impact Study with the Interconnecting Transmission Owner, and with any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, that is affected by the Interconnection Request. The System Operator and Interconnecting Transmission Owner shall utilize existing studies to the extent practicable when it performs the study. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the Interconnection System Impact Study within forty-five (45) Business

Days after the receipt of the Interconnection System Impact Study Agreement, study deposit, demonstration of Site Control, if Site Control is required, and required technical data in accordance with Section 3.4.2. At the request of the Interconnection Customer or at any time the System Operator or Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection System Impact Study, the System Operator shall notify the Interconnection Customer as to the schedule status of the Interconnection System Impact Study. If the System Operator and Interconnecting Transmission Owner are unable to complete the Interconnection System Impact Study within the time period, the System Operator shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required.

The System Operator shall notify the Interconnection Customer when the Interconnection System Impact Study is expected to commence within sixty-five (65) Calendar Days. Interconnection Customer will be permitted to update the technical data provided in Attachment 2 of this SGIP and any attachments thereto, and submit modifications to that technical data to the System Operator no later than sixty (60) Calendar Days from the date that the System Operator notified the Interconnection Customer ~~after receipt of the System Operator's notification~~ that the Interconnection System Impact Study is expected to commence. Such modifications will not be deemed Material Modifications unless the changes require a new Interconnection Request in accordance with Section 1.5.4 of this SGIP.

Where sufficient time has elapsed since the initial Scoping Meeting, within ten (10) Business Days after notifying the Interconnection Customer that the Interconnection System Impact Study is expected to commence, the System Operator may convene a second Scoping Meeting for the purpose of providing updated information to the Interconnection Customer in preparation for the submittal of updates to the technical data.

3.4.5 **Meeting with Parties.** Within ten (10) Business Days of providing an Interconnection System Impact Study report to Interconnection Customer, the System Operator shall convene a meeting of the Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, to discuss the results of the Interconnection System Impact Study. Within ~~five (5~~ten (10) Business Days following the study results meeting, the Interconnection Customer shall provide to the

Base Case – Base power flow, short circuit and stability databases, including all underlying assumptions, and contingency lists provided by System Operator, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements; such databases and lists shall include all generation projects and transmission projects that are proposed for the New England Transmission System and any Affected System and for which a transmission expansion plan has been submitted and approved by the applicable authority and which, in the sole judgment of the System Operator, may have an impact on the Interconnection Request. Base Cases also include data provided by the Interconnection Customer, where applicable, to the Interconnecting Transmission Owner and System Operator to facilitate required Interconnection Studies.

Business Day – Monday through Friday, excluding Federal Holidays.

Capacity Capability Interconnection Standard ("CC Interconnection Standard") – The criteria required to permit the Interconnection Customer to interconnect a Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service, and in a manner that ensures intra-zonal deliverability by avoidance of the redispatch of other Capacity Network Resources or Elective Transmission Upgrades with Capacity Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Capacity Network Resource ("CNR") – That portion of a Generating Facility that is interconnected to the Administered Transmission System under the Capacity Capability Interconnection Standard.

Capacity Network Resource Capability ("CNR Capability") – (i) In the case of a Generating Facility that is a New Generating Capacity Resource pursuant to Section III.13.1 of the Tariff or an Existing Generating Capacity Resource that is increasing its capability pursuant to Section III.13.1.2.2.5 of the Tariff, for Summer, the highest megawatt amount of the Capacity Supply Obligation obtained by the

Generating Facility in accordance with Section III.13 of the Tariff, and, if applicable, as specified in a filing by the System Operator with the Commission in accordance with Section III.13.8.2 of the Tariff, net of any megawatt reductions resulting from terminations, retirements or permanent de-list bids in accordance with Section III.13 of the Tariff, and, for Winter, ~~shall be~~ the Summer CNR Capability multiplied by the ratio of the associated Winter Qualified Capacity divided by the associated Summer Qualified Capacity, or (ii) in the case of a Generating Facility that meets the criteria under Section 1.6.4.3 of this SGIP, the total megawatt amount determined pursuant to the hierarchy established in Section 1.6.4.3~~.~~, net of any megawatt reductions resulting from terminations, retirements or permanent de-list bids in accordance with Section III.13 of the Tariff. The CNR Capability shall not exceed the maximum net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90 degrees F for Summer and at or above 20 degrees F for Winter. Where the Generating Facility includes multiple production devices, the CNR Capability shall not exceed the aggregate maximum net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90 degrees F for Summer and at or above 20 degrees F for Winter.

Capacity Network Resource Group Study ("CNR Group Study") – The study performed by the System Operator under Section III.13.1.1.2.3 of the Tariff to determine which resources qualify to participate in a Forward Capacity Auction.

Capacity Network Resource Interconnection Service ("CNR Interconnection Service") – The Interconnection Service selected by the Interconnection Customer to interconnect its Small Generating Facility with the Administered Transmission System in accordance with the Capacity Capability Interconnection Standard. An Interconnection Customer's CNR Interconnection Service shall be for the megawatt amount of CNR Capability. CNR Interconnection Service does not in and of itself convey transmission service.

Commercial Operation – The status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date – For a unit, the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Standard Small Generator Interconnection Agreement.

Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 3.3 and Section 3.4.

Interconnection Feasibility Study Agreement – The form of agreement contained in Attachment 6 of the Standard Small Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request – The Interconnection Request shall mean an Interconnection Customer's request, in accordance with the Tariff, to: (i) interconnect a new Generating Facility to the Administered Transmission System as either a CNR or a NR; (ii) make a Material Modification to a proposed Generating Facility with an outstanding Interconnection Request; (iii) increase the energy capability or capacity capability of or add energy storage capability to the Small Generating Facility above that specified in an Interconnection Request, an existing Interconnection Agreement (whether executed or filed in unexecuted form with the Commission), or as established pursuant to 1.6.4 of this SGIP; (~~iii~~iv) make a modification to the operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected to the Administered Transmission System; (~~iv~~v) commence participation in the wholesale markets by, an existing Generating Facility that is interconnected with the Administered Transmission System; or (~~v~~vi) change from NR Interconnection Service to CNR Interconnection Service for all or part of a Generating Facility's capability. Interconnection Request shall not include: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; or (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility.

Interconnection Service – The service provided by the System Operator and the Interconnecting Transmission Owner, associated with interconnecting the Interconnection Customer's Generating Facility to the Administered Transmission System and enabling the receipt of electric energy capability and/or capacity capability from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Small Generator Interconnection Agreement and, if applicable, the Tariff.

Party– The System Operator, Interconnecting Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Administered Transmission System.

Queue Position – The order of a valid request in the New England Control Area, relative to all other pending valid requests in the New England Control Area, that is established based upon the date and time of receipt of the valid Interconnection Request by the System Operator. Requests are comprised of interconnection requests for Generating Facilities, Elective Transmission Upgrades, requests for transmission service and notification of requests for interconnection to other electric systems, as notified by the other electric systems, that impact the Administered Transmission System. References to a "higher-queued" Interconnection Request shall mean one that has been received by System Operator (and placed in queue order) earlier than another Interconnection Request, which is referred to as "lower-queued."

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under the SGIP or SGIA, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Small Generating Facility – A Generating Facility having a maximum gross capability at or above zero degrees F of 20 MW or less.

Stand Alone Network Upgrades – Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The System Operator, Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, must agree as to what constitutes Stand Alone Network Upgrades and identify them in Attachment 2 to the Standard Small Generator Interconnection Agreement.

Study Case shall have the meaning specified in Sections 3.3.2 and 3.4.3 of this SGIP.

Attachment 2

SMALL GENERATOR INTERCONNECTION REQUEST
(Application Form)

An Interconnection Request is considered complete when it provides all applicable and correct information required below. Per SGIP Section 1.4, documentation of Site Control must be submitted with the Interconnection Request, except where the Interconnection Request is for a modification to the Interconnection Customer's existing Small Generating Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the proposed modifications do not require additional real property.

_____Site Control is not provided because the proposed modification is to the Interconnection Customer's existing Small Generating Facility and, by checking this option, the Interconnection Customer certifies that it has Site Control and that the proposed modification does not require additional real property.

Preamble and Instructions

An Interconnection Customer who requests a Federal Energy Regulatory Commission jurisdictional interconnection that is subject to this SGIP must submit this Interconnection Request ~~by hand delivery, mail, e-mail, or fax to~~ to the System Operator~~.~~ via the Interconnection Request Tracking Tool or IRTT, a web-based application for submitting, tracking and viewing Interconnection Requests available on the ISO New England website.

Processing Fee or Deposit:

If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is $4.50/kW (minimum of $300 and maximum of $7,500). The kW are the maximum gross kW of the Small Generating Facility. The Fast Track Process is limited to a Small Generating Facility that meets the eligibility requirements of section 2.1 and certain codes, standards and certification requirements.

Address: _____

_____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

Application is for: _____New Small Generating Facility

_____Capacity addition to or modification of an ~~Existing~~existing Small Generating Facility

_____Commencement of participation in the wholesale markets by an ~~Existing~~existing Small Generating Facility

_____A change from Network Resource Interconnection Service to Capacity Network Resource Interconnection Service

If capacity addition to or modification of an existing facility, please describe: _____

_____

If the capacity addition increases the maximum gross megawatt electrical output at an ambient temperature of 20 degrees F of the Generating Facility to more than 20 MW, the Interconnection Customer shall apply under Schedule 22.

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ___ No ___

To Supply Power to the Interconnection Customer? Yes ___No ___

To Supply Power to Others? Yes ____ No ____

Is the Interconnection Request for:

Service Type (check one):

Interconnection Request: _____ Elevation: _____ ___Single phase ___Three phase

Inverter Manufacturer, Model Name & Number (if used): _____

List of adjustable set points for the protective equipment or software: _____

Model Requirements

For all generation types: A completed, fully functioning, public (*i.e.*, non-proprietary or non-confidential) Siemens PTI's ("PSSE") power flow model or other compatible formats, such as IEEE and General Electric Company Power Systems Load Flow ("PSLF") data sheet, must be supplied with this Interconnection Request. If additional ~~non-proprietary or non-confidential~~public data sheets are more appropriate to the proposed device then they shall be provided and discussed at ~~Scoping Meeting.~~the Scoping Meeting. For all Interconnection Studies commencing after January 1, 2017, all power flow models must be standard library models in PSS/E or applicable applications. After January 1, 2017, user-models will not be accepted.

A PSCAD model for all wind and inverter-based Small Generating Facilities must be supplied with this Interconnection Request. If a PSCAD model is deemed required for other Generating Facility types at the Scoping Meeting, such PSCAD model must be provided to the System Operator within ninety (90) Calendar Days of the Scoping Meeting date or the executed Interconnection System Impact Study Agreement (whichever is later). A benchmarking anaylsis consistent with the requirements in the ISO New England Planning Procedures, confirming acceptable performance of the PSS/E model in comparison to the PSCAD model, shall be provided at the time the PSCAD model is submitted.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: _____ Instantaneous ___ or RMS? _____

Harmonics Characteristics: _____

Start-up requirements: _____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____

Neutral Grounding Resistor (If Applicable): _____

Synchronous Generators:

Generator AC resistance Ra_____

Direct Axis Synchronous Reactance, Xd: _____ P.U.

Direct Axis Transient Reactance, X'_d: _____P.U.

Direct Axis Subtransient Reactance, X''_d: _____P.U.

Negative Sequence Reactance, X_2: _____ P.U.

Zero Sequence Reactance, X_0: _____ P.U.

KVA Base: _____

Field Volts: _____

Field Amperes: _____

Induction Generators:

Motoring Power (kW): _____

I_2^2t or K (Heating Time Constant): _____

Rotor Resistance, Rr: _____

Stator Resistance, Rs: _____

Stator Reactance, Xs: _____

Rotor Reactance, Xr: _____

Magnetizing Reactance, Xm: _____

Short Circuit Reactance, Xd": _____

Exciting Current: _____

Temperature Rise: _____

Frame Size: _____

Design Letter: _____

Reactive Power Required In Vars (No Load): _____

Reactive Power Required In Vars (Full Load): _____

Total Rotating Inertia, H: _____ Per Unit on kVA Base

Note: Please contact the System Operator prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling? ___Yes ___No

Will the transformer be provided by the Interconnection Customer? ____Yes ____No

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ____single phase _____three phase? Size: _____kVA

Transformer Impedance: _____% on _____kVA Base

If Three Phase:

Transformer Primary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Secondary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Tertiary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: _____ Type: _____ Size: _____Speed: _____

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ___Yes ____No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).
Are Schematic Drawings Enclosed? ___Yes ____No

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer: _____Date: _____

In order for a Small Generator Interconnection Request to be considered a valid request, it must:

(a) *Be accompanied by the applicable deposit~~,~~ that is provided electronically and which shall be non-refundable;*
(b) *Include documentation of Site Control, if applicable;*
(c) *Include a detailed map ~~(2 copies),~~, such as a map of the quality produced by the U.S. Geological Survey, which clearly indicates the site of the new facility and pertinent surrounding structures;*
(d) *Include two copies, signed and stamped by a licensed Professional Engineer, of the site electrical one-line diagram; and*
(e) *Include all information and data required on the Interconnection Request form and any attachments thereto.*

The Interconnection Request must be submitted to the System Operator via the Interconnection Request Tracking Tool or IRTT.

Attachment A to Interconnection Request Form

SUPPLEMENTARY WIND AND INVERTER-BASED GENERATING FACILITY DATA FORM

1. Attach a Geographic Map Demonstrating the Project Layout and its Interconnection to the Power Grid. *(Specify the name of the attachment here)*

2. Attach a Bus-Breaker Based One-line Diagram (The diagram should include each of the individual wind unit, generator number, rating and terminal voltage.) *(Specify the name of the attachment here)*

2.1 Collection system detail impedance sheet

If a collector system is used, attach a collector system data sheet in accordance with the one-line diagram attached above. The data sheet should include: the type, length Z_0, Z_1 and Xc/B of each circuit (feeder and collector string).

Specify the name of the attachment here: _____

2.2 Collection system aggregate (equivalent) model data sheet

Attach an aggregate (equivalent) collection system data sheet. The data table should include: the type, length, Z_0, Z_1 and Xc/B of the equivalent circuits (feeders and collector strings).

Specify the name of the attachment here: _____

3. Summary of the Unit Models in the wind or inverter-based generating facility *(List all different unit models in the facility)*

Manufacturer Model	Type of this WTG* (if applicable)	Generator Unit numbers in the field	Number(s) of these Units	Maximum Output of this Unit(MW)	Total MW

……..					

* Type 1 – Cage rotor induction generators
Type 2 – Induction generators with variable rotor resistance
Type 3 – Doubly-fed asynchronous generators with rotor-side converter
Type 4 – Full-power converter interface

Repeat the following sections from 6 to 14 for each different unit model.

4. Unit Detail Information

Unit Manufacturer Model	
Terminal Voltage	
Rating of Each Unit (MVA)	
Maximum Gross Electrical Output (MW)	
Minimum Gross Electrical Output(MW)	
Lagging Reactive Power Limit at Rated Real Power Output (MVAR)	
Leading Reactive Power Limit at Rated Real Power Output (MVAR)	
Lagging Reactive Power Limit at Zero Real Power Output (MVAR)	
Leading Reactive Power Limit at Zero Real Power Output (MVAR)	
Station Service Load(MW, MVAR)	
Minimum short circuit ratio(SCR) requirement by manufacturer	
On which bus the minimum SCR is required by manufacturer	
What voltage level the minimum SCR is required by manufacturer	
Positive sequence Xsource	
Zero sequence Xsource	

5. Unit GSU – _____

Nameplate rating(MVA)	

Total number of the GSUs	
Voltages, generator side/system side	
Winding connections, low voltage/high voltage	
Available tap positions on high voltage side	
Available tap positions on low voltage side	
Will the GSU operate as an LTC?	
Desired voltage control range if LTC	
Tap adjustment time (Tap switching delay + switching time) if LTC	
Desired tap position if applicable	
Impedance, Z1, X/R ratio	
Impedance, Z0, X/R ratio	

6. Low Voltage Ride Through(LVRT) – _____ *(Specify the Manufacturer Model of this Unit)*

Does each Unit have LVRT capability?

Yes__ _____ No__

If yes, please provide:

6.1 Unit LVRT mode activation and release condition:

When operating at maximum real power, what is the Unit terminal voltage for LVRT mode activation? _____

When operating at maximum real power, what is the Unit terminal voltage for releasing LVRT mode after it is activated? _____

If there is different LVRT activation and release logic, please state here_____

6.2 A wind or inverter-based generating facility technical manual from the manufacturer including description of LVRT functionality:

Attach the file and specify the name of the attachment here:

_____

6.3 Does the wind or inverter-based generating facility technical manual attached above include a reactive power capability curve?

Yes__ No__

If no, attach the file and specify the name of the attachment here:

_____

7. Low Voltage Protection (considering LVRT functionality)

(Specify the Manufacturer Model of this Unit)

Low Voltage Setting (pu)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

8. High Voltage Protection - _____(Specify the Manufacturer Model of this Unit)

High Voltage Setting (pu)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

9. Low Frequency Protection - _____(Specify the Manufacturer Model of this Unit)

Low Frequency Setting(Hz)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

10. High Frequency Protection - _____(Specify the Manufacturer Model of this Unit)

High Frequency Setting(Hz)	Relay Pickup Time (Seconds)

*Add more rows in the table as needed

Please make sure the settings in section 8 through 11 comply with NERC and NPCC standards for generator protection relays.

11. Unit Reactive Power Control - ____ (Specify the Manufacturer Model of this Unit)

11.1 What are the options for the Unit reactive power control (check all available)?

_____ Control the voltage at the Unit terminal

____Control constant power factor at the Unit terminal

____Control constant power factor at the low side of the station main transformer

____Control constant power factor at the high side of the station main transformer

____Control voltage at the low side of the station main transformer

____Control voltage at the high side of the station main transformer

____Other options. Please describe if select others_____

11.2 In all the control options selected above, please list the options in which the Unit is able to control its terminal voltage to prevent low/high voltage tripping.

_____

11.3 What is the desired control mode from the selected options above? Specify the control plan in this mode. For example: control voltage at which bus to what schedule.

_____

12. Wind or inverter-based generating facility Model

(All model files provided in section 13 should be compatible with Siemens PTI's PSS/E version currently in use at ISO New England)

12.1 Power flow model

12.1.1 A *. RAW file including **aggregated/equivalent** wind or inverter-based generating facility power flow model with appropriate parameters and settings.

Attach the *.RAW file and specify the name of the attachment here:

_____

12.1.2 A *. RAW file including **detailed** wind or inverter-based generating facility power flow model with appropriate parameters and settings. *(Optional)*

Attach the *.RAW file and specify the name of the attachment here:

_____

12.2 Dynamic simulation model

(Please note that the dynamic model must match the aggregated/equivalent power flow model provided above. Attach the following information for each of the models.)

12.2.1 Wind or inverter-based generating facility Model _____(Please Specify the Manufacturer Model)

12.2.2 A compiled PSS/E dynamic model for the turbines (a *.LIB or *.OBJ file)

Attach the *.LIB or *.OBJ file and specify the name of the attachment here:

_____

12.2.3 A dynamic data file with appropriate parameters and settings for the turbines (typically a *.DYR file)

Attach the *.DYR file and specify the name of the attachment here:

_____

12.2.4 PSS/E wind or inverter-based generating facility model user manual for the WTG

Attach the and specify the name of the attachment here:

_____

Rrepeat the above sections from 6 to 14 for each different wind or inverter-based generating facility model)

13. Power Plant Controller

Will the wind or inverter-based generating facility be equipped with power plant controller, which has the ability to centrally control the output of the units?

Yes__ _____ No__

_____ If yes, please provide:

13.1 Manufacturer model of the power plant controller

_____

13.2 What are the reactive power control strategy options of the power plant controller?

-
-

…….

13.3 Which of the control option stated above is being used in current operation?

_____

13.4 Is the power plant controller able to control the unit terminal voltages to prevent low/high voltage tripping?

Yes__ No__

Please provide the park controller technical manual from the manufacturer

Attach the file and specify the name of the attachment here:

_____

14. Station Transformer

Transformer Name		
Nameplate ratings(MVA)		
Total number of the main transformer(s)		
Voltages, High/Low/Tertiary (kV)		
Winding connections, High/Low/Tertiary		
Available tap positions on high voltage side		
Available tap positions on low voltage side		
Will the transformer operate as a LTC?		
Desired voltage control range if LTC		
Tap adjustment time (Tap switching delay + switching time) if LTC		
Desired tap position if applicable		
Tap adjustment time (Tap switching delay + switching time)		
Impedance Z_1, X/R ratio	Z_{1H-L}	X/R
	Z_{1H-T}	X/R
	Z_{1T-L}	X/R

Impedance Z_0, X/R ratio	Z_{0H-L}	X/R
	Z_{0H-T}	X/R
	Z_{0T-L}	X/R

15. Dynamic Simulation Model for the Power Plant Controller (if applicable)

(All model files provided in section 16 should be compatible with Siemens PTI's PSS/E version currently in use at ISO New England)

15.1 A compiled PSS/E dynamic model for the power plant controller (a *.LIB or *.OBJ file)

Attach the *.LIB or *.OBJ file and specify the name of the attachment here:

_____

15.2 A dynamic data file with appropriate parameters and settings for the power plant controller (typically a *.DYR file).

Please set the parameters in accordance with the currently used control mode.

Attach the *.DYR file and specify the name of the attachment here:

_____

15.3 PSS/E model user manual for the power plant controller

Attach the manual and specify the name of the attachment or specify the name of the attachment here:_____

16. Capacitors and Reactors

Please provide necessary modeling data for all the capacitors and reactors belong to the facility, including: size, basic electrical parameters, connecting bus, switched or fixed, etc.

17. Dynamic Device

(All model files provided in section 18 should be compatible with Siemens PTI's PSS/E version currently in use at ISO New England)

17.1 Provide necessary modeling data file for all the dynamic devices belong to the facility.

Attach the *.LIB or *.OBJ file and specify the name of the attachment here:

_____

17.2 A dynamic data file containing the parameters for the units (typically a *.DYR file).

Set the parameters in accordance with the desired control mode.

Attach the *.DYR file and specify the name of the attachment here:

_____

18. Collection System/Transmformer Tap-Setting Design

Attach a collection system/transformer tap-setting design calculations, consistent with the requriements in the ISO New England Planning Procedures, that identify the calculations to support the proposed tap settings for the unit step-up transformers and the station step-up transformers.

Attach the design document and specify the name of the attachment here:

_____

19. Additional Information

Are there any special features available to be implemented to the wind or inverter-based generating facility? Such as weak grid interconnection solutions, etc.

Specify the available features here:

_____

Insert the technical manual for each of the features listed above as objects (display as icons) or specify the name of the attachment here: _____

20. PSCAD Model and Documentation for the wind or inverter-based generating facility, the Power Plant Controller and Other Dynamic Devices for the wind or inverter-based generating facility.

ISO will determine how much PSCAD work is needed from the wind or inverter-based generating facility ***based on its interconnection system conditions.***

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the Small Generator Interconnection Procedures (SGIP), or the Interconnecting Transmission Owner has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1. _____	_____
2. _____	_____
3. _____	_____
4. _____	_____
5. _____	_____

Interconnection Customer Signature

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: _____

Title: _____ Date: _____

Contingent Approval to Interconnect the Small Generating Facility

(For Internal use only)

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Interconnecting Transmission Owner Signature: _____

Title: _____ Date: _____

Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

1.0 Construction of the Facility

The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the System Operator approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 Interconnection and Operation

The Customer may operate Small Generating Facility and interconnect with the Interconnecting Transmission Owner's (the "Company") electric system once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the System Operator and the Company, and

2.3 The Company has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Company, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Company shall provide a written statement that the Small Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Company does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

Attachment 6

Interconnection Feasibility Study Agreement

THIS AGREEMENT is made and entered into this_____day of_____ 20___ by and between_____, a_____organized and existing under the laws of the State of _____, ("Interconnection Customer,") and ISO New England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System Operator"), and_____, a_____ existing under the laws of the State of_____, ("Interconnecting Transmission Owner"). Interconnection Customer, System Operator and Interconnecting Transmission Owner each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on_____; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Administered Transmission System; and

WHEREAS, Interconnection Customer has requested the System Operator and Interconnecting Transmission Owner to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Small Generating Facility with the facilities that are part of the Interconnecting Transmission Owner's Administered Transmission System, and of any Affected Systems.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures

("SGIP"), or in the other provisions of the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff").

2.0 The Interconnection Customer elects and the System Operator and Interconnecting Transmission Owner shall cause to be performed an Interconnection Feasibility Study consistent the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection Feasibility Study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The System Operator and Interconnecting Transmission Owner reserve the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the Interconnection Feasibility Study may be extended by agreement of the Parties.

5.0 In performing the study, the System Operator and Interconnecting Transmission Owner shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the Interconnection Feasibility Study.

6.0 The Interconnection Feasibility Study report shall provide the following analyses depending on whether the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and short circulated analysis, or limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient analysis, as appropriate, focusing on the issues that are expected to be the most significant for ~~for the purpose of identifying any potential adverse system impacts that would result from~~ the interconnection of the Small Generating Facility as proposed given recent study experience and as discussed at the Scoping Meeting:

6.1 Initial identification of any circuit breaker or other facility short circuit capability limits exceeded as a result of the interconnection, or, findings of the limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient analysis, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Small Generating Facility's interconnection given recent study experience and as discussed at the Scoping Meeting;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection~~;~~, or, a preliminary description of and ~~, to the extent readily available to the Interconnecting Transmission Owner,~~ a non-binding good faith order of magnitude estimated cost of (unless such cost estimate is waived by the Interconnection Customer) ~~estimated cost of~~ and the time to construct the Interconnection Facilities and Network Upgrades necessary to interconnect the Small Generating Facility as identified within the scope of the analysis performed as part of the study;

6.3 If the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and short circuit analysis, ~~I~~initial review of grounding requirements and electric system protection; and

6.4 If the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and short circuit analysis, ~~D~~description and non-binding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues and length of time that would be necessary to construct the facilities.

6.5 To the extent the Interconnection Customer requested a preliminary analysis as described in Section 3.3.2 of the SGIP, the report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

7.0 The Interconnection Feasibility Study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9.0 A deposit, paid to the System Operator, of the lesser of 50 percent of good faith estimated Interconnection Feasibility Study costs or earnest money of $1,000 shall be required from the Interconnection Customer.

10.0 Once the Interconnection Feasibility Study is completed, an Interconnection Feasibility Study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the Interconnection Feasibility Study must be completed and the Interconnection Feasibility Study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct an Interconnection Feasibility Study.

11.0 The total estimated cost of the performance of the Interconnection Feasibility Study consists of $ [insert], which is comprised of the System Operator's cost of $[insert] and the Interconnecting Transmission Owner's cost of $[insert]. The Interconnection Customer may be invoiced on a monthly basis for work to be conducted.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the System Operator shall refund such excess within 30 calendar days of the invoice without interest.

13.0 Miscellaneous.

13.1 Accuracy of Information. Except as a Party ("Providing Party") may otherwise specify in writing when it provides information to the other Parties under this Agreement, the Providing Party represents and warrants that, to the best of its knowledge, the information it provides to the other Parties shall be accurate and complete as of the date the information is provided. The Providing Party shall promptly provide the other Parties with any additional information needed to update information previously provided.

13.2 Disclaimer of Warranty. In preparing and/or participating in the Interconnection Feasibility Study, as applicable, each Party and any subcontractor consultants employed by it shall have to rely on information provided by the Providing Party, and possibly by third parties, and may not have control over the accuracy of such information.

be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties.

10.0 A deposit of the equivalent of the good faith estimated cost of a distribution Interconnection System Impact Study shall be paid to the System Operator by the Interconnection Customer; and the one half the good faith estimated cost of a transmission Interconnection System Impact Study shall be paid to the System Operator by the Interconnection Customer.

11.0 The total estimated cost of the performance of the Interconnection System Impact Study consists of $[insert], which is comprised of the System Operator's cost of $[insert] and the Interconnecting Transmission Owner's cost of $[insert]. The Interconnection Customer may be invoiced on a monthly basis for work to be conducted.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the System Operator or Interconnecting Transmission Owner, as applicable, shall refund such excess within 30 calendar days of the invoice without interest.

13.0 Miscellaneous.

13.1 Accuracy of Information. Except as a Party ("Providing Party") may otherwise specify in writing when it provides information to the other Parties under this Agreement, the Providing Party represents and warrants that, to the best of its knowledge, the information it provides to the other Parties shall be accurate and complete as of the date the information is provided. The Providing Party shall promptly provide the other Parties with any additional information needed to update information previously provided.

13.2 Disclaimer of Warranty. In preparing and/or participating in the Interconnection System Impact Study, as applicable, each Party and any subcontractor consultants employed by it shall have to rely on information provided by the Providing Party, and possibly by third parties, and may not have control over the accuracy of such information. Accordingly, beyond the commitment to use Reasonable Efforts in preparing and/or participating in the Interconnection System Impact Study (including, but not limited to, exercise of Good Utility Practice in verifying the accuracy of information provided for or used in the

Attachments to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of change of ownership. The Interconnecting Transmission Owner and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the New England Transmission System [or Interconnecting Transmission Owner's transmission facilities], personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Agreement.

1.5.6 The System Operator, with input from the Interconnecting Transmission Owner, shall coordinate with all Affected Systems to support the interconnection.

1.6 Parallel Operation Obligations

Once the Small Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Small Generating Facility in the applicable control area, including, but not limited to the ISO New England Operating Documents, and the Operating Requirements set forth in Attachment 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the Interconnecting Transmission Owner's reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachment 2 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

1.8 Reactive Power

1.8.1 The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of

Interconnection ~~at a~~with dynamic reactive capability over the power factor ~~within the~~ range of 0.95 leading to 0.95 lagging, unless the System Operator or Interconnecting Transmission Owner has established different requirements that apply to all similarly situated generators on a comparable basis and in accordance with Operating Requirements. The requirements of this paragraph shall not apply to wind generators. Wind Generating Facilities shall be subject to the power factor design criteria specified in Appendix G to the LGIP. Wind and inverter-based Generating Facilities shall be subject to the Low Voltage Ride-Through Capability requirements specified in Appendix G to the LGIP.

1.8.2 Interconnection Customers shall be compensated for reactive power service in accordance with Schedule 2 of the Tariff.

1.9 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of this Agreement. Capitalized terms in Schedule 23 that are not defined in the Glossary of Terms shall have the meanings specified in Sections I.2.2. of the Tariff.

1.10 Scope of Service

1. 10.1 Interconnection Product Options. Interconnection Customer has selected the following (checked) type of Interconnection Service:

_____ NR for NR Interconnection Service (NR Capability Only)
_____ CNR for CNR Interconnection Service (NR Capability and CNR Capability)

1.10.1.1 Capacity Network Resource Interconnection Service (CNR Interconnection Service

(a) The Product. The System Operator and Interconnecting Transmission Owner must conduct the necessary studies and the Interconnecting Transmission Owner and Affected Parties must construct the Network Upgrades needed to interconnect the Small Generating Facility in a manner comparable to that in

Attachment 1

Glossary of Terms

Administered Transmission System – The PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Affected Party– The entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affected System – Any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affiliate – With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Standards – The requirements and guidelines of NERC, NPCC and the New England Control Area, including publicly available local reliability requirements of Interconnecting Transmission Owners or other Affected Systems.

At-Risk Expenditure – Money expended for the development of the Generating Facility that cannot be recouped if the Interconnection Customer were to withdraw the Interconnection Request for the Generating Facility. At-Risk Expenditure may include, but is not limited to, money expended on: (1) costs of federal, state, local, regional and town permits, (ii) Site Control, (iii) site-specific design and survey, (iv) construction activities, and (v) non-refundable deposits for major equipment components. For purposes of this definition, At-
Risk Expenditure shall not include costs associated with the Interconnection Studies.

Base Case – Base power flow, short circuit and stability databases, including all underlying assumptions, and contingency lists provided by System Operator, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements; such databases and lists shall include all generation projects and transmission projects that are proposed for the New England Transmission System and any Affected System and for which a transmission expansion plan has been submitted and approved by the applicable authority and which, in the sole judgment of the System Operator, may have an impact on the Interconnection Request. Base Cases also include data provided by the Interconnection Customer, where applicable, to the Interconnecting Transmission Owner and System Operator to facilitate required Interconnection Studies.

Business Day – Monday through Friday, excluding Federal Holidays.

Capacity Capability Interconnection Standard ("CC Interconnection Standard") – The criteria required to permit the Interconnection Customer to interconnect a Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service, and in a manner that ensures intra-zonal deliverability by avoidance of the redispatch of other Capacity Network Resources and Elective Transmission Upgrades with Capacity Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Capacity Network Resource ("CNR") – That portion of a Generating Facility that is interconnected to the Administered Transmission System under the Capacity Capability Interconnection Standard.

Capacity Network Resource Capability ("CNR Capability") -- (i) In the case of a Generating Facility that is a New Generating Capacity Resource pursuant to Section III.13.1 of the Tariff or an Existing Generating Capacity Resource that is increasing its capability pursuant to Section III.13.1.2.2.5 of the Tariff, for Summer, the highest megawatt amount of the Capacity Supply Obligation obtained by the Generating Facility in accordance with Section III.13 of the Tariff, net of any megawatt reductions

resulting from terminations, retirements or permanent de-list bids in accordance with Section III.13 of the Tariff, and, for Winter, ~~shall be~~ the Summer CNR Capability multiplied by the ratio of the associated Winter Qualified Capacity divided by the associated Summer Qualified Capacity, and, if applicable, as specified in a filing by the System Operator with the Commission in accordance with Section III.13.8.2 of the Tariff, or (ii) in the case of a Generating Facility that meets the criteria under Section 1.6.4.3 of the Small Generator Interconnection Procedures ("SGIP"), the total megawatt amount determined pursuant to the hierarchy established in Section 1.6.4.3~~.~~, net of any megawatt reductions resulting from temrinations, retirements or permanent de-list bids in accordance with Section III.13 of the Tariff. The CNR Capability shall not exceed the maximum net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90degrees F for Summer and at or above 20 degrees F for Winter. Where the Generating Facility includes multiple production devices, the CNR Capability shall not exceed the aggregate maximum net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90 degrees F for Summer and at or above 20 degrees F for Winter.

Capacity Network Resource Group Study ("CNR Group Study") – The study performed by the System Operator under Section III.13.1.1.2.3 of the Tariff to determine which resources qualify to participate in a Forward Capacity Auction.

Capacity Network Resource Interconnection Service ("CNR Interconnection Service") -- The Interconnection Service selected by the Interconnection Customer to interconnect its Small Generating Facility with the Administered Transmission System in accordance with the Capacity Capability Interconnection Standard. An Interconnection Customer's CNR Interconnection Service shall be for the megawatt amount of CNR Capability. CNR Interconnection Service does not in and of itself convey transmission service.

Commercial Operation – The status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date – The date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Attachment 7 to the Standard Small Generator Interconnection Agreement.

Attachment 2

Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment

Equipment, including the Small Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer or the Interconnecting Transmission Owner. The Interconnecting Transmission Owner will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

I. DESCRIPTION OF MAJOR COMPONENTS

A. Small Generating Facility

(1) Description of Small Generating Facility.

[*insert*]

(2) The Small Generating Facility shall receive:

___ Network Resource Interconnection Service for the NR Capability at a level not to exceed [insert gross and net at or above 50 degrees F] MW for Summer, and [insert gross and net at or above 0 degrees F] MW for Winter.

___ Capacity Network Resource Interconnection Service for: (a)(i) the NR Capability at a level not to exceed [insert gross and net at or above 50 degrees F] MW for Summer and [insert gross and net at or above 0 degrees F] MW for Winter; and (ii) the CNR Capability at [insert net] MW for Summer and [insert net] MW for Winter, which shall not exceed [insert the maximum net MW electrical output of the Generating Facility at an ambient temperature at or above 90 degrees F for summer and at or above 20 degrees F for winter]. ~~The CNR Capability shall be the amount~~

~~of the Capacity Supply Obligation obtained by the Generating Facility in accordance with Section III.13 of the Tariff and, if applicable, as specified in filings by the System Operator with the Commission pursuant to Section III.13 of the Tariff.~~

Draft Revisions

New Interconnection Requirements

January 26, 2016 TC Meeting (FOR VOTE)

As Voted by the TC

SCHEDULE 25

ELECTIVE TRANSMISSION UPGRADE INTERCONNECTION PROCEDURES

TABLE OF CONTENTS

SECTION 1. DEFINITIONS
SECTION 2. SCOPE, APPLICATION AND TIME REQUIREMENTS
2.1 Application of Elective Transmission Upgrade Interconnection Procedures
2.2 Comparability
2.3 Base Case Data
2.4 No Applicability to Transmission Service
2.5 Treatment of Elective Transmission Upgrades for Transmission, Operations, and Scheduling Purposes
2.6 Time Requirements
SECTION 3. INTERCONNECTION REQUESTS
3.1 General
3.2 Type of Interconnection Services and Long Lead Time Facility Treatment
3.3 Valid Interconnection Request
3.4 OASIS Posting
3.5 Coordination with Affected Systems
3.6 Withdrawal
SECTION 4. QUEUE POSITION
4.1 General
4.2 Reserved
4.3 Transferability of Queue Position
4.4 Modifications
SECTION 5. PROCEDURES FOR TRANSITION
5.1 Queue Position for Pending Requests
5.2 Reserved
5.3 New System Operator or Interconnecting Transmission Owner
SECTION 6. INTERCONNECTION FEASIBILITY STUDY
6.1 Interconnection Feasibility Study Agreement
6.2 Scope of Interconnection Feasibility Study
6.3 Interconnection Feasibility Study Procedures
6.4 Re-Study
SECTION 7. INTERCONNECTION SYSTEM IMPACT STUDY
7.1 Interconnection System Impact Study Agreement

7.2 Execution of Interconnection System Impact Study Agreement
7.3 Scope of Interconnection System Impact Study
7.4 Interconnection System Impact Study Procedures
7.5 Meeting with Parties
7.6 Re-Study
7.7 Operational Readiness
SECTION 8. INTERCONNECTION FACILITIES STUDY
8.1 Interconnection Facilities Study Agreement
8.2 Scope of Interconnection Facilities Study
8.3 Interconnection Facilities Study Procedures
8.4 Meeting with Parties
8.5 Re-Study
SECTION 9. ENGINEERING & PROCUREMENT ("E&P") AGREEMENT
SECTION 10. OPTIONAL INTERCONNECTION STUDY
10.1 Optional Interconnection Study Agreement
10.2 Scope of Optional Interconnection Study
10.3 Optional Interconnection Study Procedures
10.4 Meeting with Parties
10.5 Interconnection Agreement Developed Based on Optional Interconnection Study
SECTION 11. ELECTIVE TRANSMISSION UPGRADE INTERCONNECTION AGREEMENT (ETU IA)
11.1 Tender
11.2 Negotiation
11.3 Evidence to be Provided by Interconnection Customer; Execution and Filing of ETU IA
11.4 Commencement of Interconnection Activities
11.5 Other Regulatory Arrangements
SECTION 12. CONSTRUCTION OF INTERCONNECTING TRANSMISSION OWNER INTERCONNECTION FACILITIES AND NETWORK UPGRADES
12.1 Schedule
12.2 Construction Sequencing
SECTION 13. MISCELLANEOUS
13.1 Confidentiality
13.2 Delegation of Responsibility
13.3 Obligation for Study Costs

13.4 Third Parties Conducting Studies

13.5 Disputes

13.6 Local Furnishing Bonds

APPENDICES TO ETU INTERCONNECTION PROCEDURES

APPENDIX 1 INTERCONNECTION REQUEST

APPENDIX 2 INTERCONNECTION FEASIBILITY STUDY AGREEMENT

APPENDIX 3 INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

APPENDIX 4 INTERCONNECTION FACILITIES STUDY AGREEMENT

APPENDIX 5 OPTIONAL INTERCONNECTION STUDY AGREEMENT

APPENDIX 6 ELECTIVE TRANSMISSION UPGRADE INTERCONNECTION AGREEMENT

Capacity Resource(s) associated with the External Elective Transmission Upgrade, net of any megawatt reductions, in accordance with Section III.13 of the Tariff. The Capacity Network Import Capability shall be the maximum net megawatt electrical capability at the Point of Interconnection consistent with the Capacity Capability Interconnection Standard and shall not to exceed applicable seasonal equipment ratings determined pursuant to industry standards and consistent with the specifications described in ISO New England Planning and Operating Procedures.

Capacity Network Import Interconnection Service ("CNI Interconnection Service") shall mean, for an External Elective Transmission Upgrade that is a controllable Merchant Transmission Facility or Other Transmission Facility, the Interconnection Service selected by the Interconnection Customer to interconnect its Elective Transmission Upgrade with the Administered Transmission System in accordance with the Capacity Capability Interconnection Standard. An Interconnection Customer's Capacity Network Import Interconnection Service shall be for the megawatt of Capacity Network Import Capability. Capacity Network Import Interconnection Service does not in and of itself convey transmission service.

Capacity Network Resource Group Study ("CNR Group Study") shall mean the study performed by the System Operator under Section III.13.1.1.2.3 of the Tariff to determine which resources qualify to participate in a Forward Capacity Auction.

Commercial Operation shall mean the status of an Elective Transmission Upgrade that has commenced transmitting electricity, excluding performance during Trial Operation.

Commercial Operation Date shall mean the date on which the Elective Transmission Upgrade commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Elective Transmission Upgrade Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise. Confidential Information shall include, but not be limited to, information that is confidential pursuant to the ISO New England Information Policy.

Interconnection Customer has the option to request either that the Interconnection Feasibility Study be completed as a separate and distinct study, or as part of the Interconnection System Impact Study. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 6 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 6 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 6 and Section 7.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Elective Transmission Upgrade Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Elective Transmission Upgrade Interconnection Procedures, in accordance with the Tariff, to: (i) interconnect a new Elective Transmission Upgrade to the Administered Transmission System; (ii) make a Material Modification to an Elective Transmission Upgrade with an outstanding Interconnection Request; (iii) increase the capability of an existing Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility that is interconnected to the Administered Transmission System; ~~or (iii~~(iv) make a Material Modification to the design or operating characteristics of an existing Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility that is interconnected with the Administered Transmission System~~.~~; or (v) change from NI Interconnection Service to CNI Interconnection Service for an Elective Transmission Upgrade that is eligible to request such services. Interconnection Request shall not include a request to interconnect to a transmission facility that is not part of the Administered Transmission System.

Interconnection Service shall mean the right to interconnect the Interconnection Customer's Elective Transmission Upgrade to the Administered Transmission System at the Point of Interconnection pursuant to the terms of the Elective Transmission Upgrade Interconnection Agreement and, if applicable, the Tariff. For an External Elective Transmission Upgrade that is a controllable Merchant Transmission Facility or Other Transmission Facility, Interconnection Service shall include Capacity Network Import Interconnection Service or Network Import Interconnection Service.

Long Lead Time Facility ("Long Lead Facility") shall mean a Generating Facility or an Elective Transmission Upgrade with an Interconnection Request for Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service, respectively, that has, as applicable, elected or requested long lead time treatment and met the eligibility criteria and requirements specified in Schedule 22 or Schedule 25 of Section II of the Tariff, respectively,

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Elective Transmission Upgrade Interconnection Agreement on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnifying Party.

Major Permits shall be as defined in Section III.13.1.1.2.2.2(a) of the Tariff.

Material Modification shall mean: (i) except as expressly provided in Section 4.4.1, those modifications to the Interconnection Request, including any of the technical data provided by the Interconnection Customer in Attachment A to the Interconnection Request or to the interconnection configuration, requested by the Interconnection Customer, that either require significant additional study of the same Interconnection Request and could substantially change the interconnection design, or have a material impact (*i.e.*, an evaluation of the proposed modification cannot be completed in less than ten (10) Business Days) on the cost or timing of any Interconnection Studies or upgrades associated with an Interconnection Request with a later queue priority date; (ii) a change to the design or operating characteristics of an existing Pool Transmission Facility, Merchant Transmission Facility, or Other Transmission Facility that is interconnected with the Administered Transmission System that may have a significant adverse effect on the reliability or operating characteristics of the New England Transmission System; (iii) a delay to the Commercial Operation Date, In-Service Date, or Trial Operation Date of greater than three (3) years where the reason for delay is unrelated to construction schedules or permitting which delay is beyond the Interconnection Customer's control; (iv) except as provided in Section 3.2.3.4, a withdrawal of a request for Long Lead Facility treatment; or (v) except as provided in Section 3.2.3.6, an election to participate in an earlier Forward Capacity Auction than originally anticipated.

Metering Equipment shall mean all metering equipment installed or to be installed pursuant to the Elective Transmission Upgrade Interconnection Agreement, including but not limited to instrument

Scoping Meeting shall mean the meeting between representatives of the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (a) that the Interconnection Customer is the owner in fee simple of the real property or holds an easement for the Elective Transmission Upgrade's terminal locations at the Point of Interconnection within the New England Control Area; (b) that the Interconnection Customer holds a valid written leasehold or other contractual interest in the real property for the Elective Transmission Upgrade's terminal locations at the Point of Interconnection within the New England Control Area; (c) that the Interconnection Customer holds a valid written option to purchase or a leasehold interest in the real property for the Elective Transmission Upgrade's terminal locations at the Point of Interconnection within the New England Control Area; (d) that the Interconnection Customer holds a duly executed written contract to purchase, acquire an easement, a license or a leasehold interest in the real property for the Elective Transmission Upgrade's terminal locations at the Point of Interconnection within the New England Control Area; or (e) that the Interconnection Customer has filed applications for required permits to site on federal or state property where the Elective Transmission Upgrade's terminal locations will be located at the Point of Interconnection within the New England Control Area.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The System Operator, Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Elective Transmission Upgrade Interconnection Agreement.

Study Case shall have the meaning specified in Sections 6.2 and 7.3 of this ETU IP.

System Protection Facilities shall mean the equipment, including necessary signal protection communications equipment, required to protect (1) the New England Transmission System from faults or other electrical disturbances occurring at the Elective Transmission Upgrade and (2) the Elective Transmission Upgrade from faults or other electrical system disturbances occurring on the New England Transmission System or on other delivery systems or other generating systems to which the New England Transmission System is directly connected.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Elective Transmission Upgrade prior to Commercial Operation.

Trial Operation Date shall mean the date upon which the Elective Transmission Upgrade begins Trial Operation.

SECTION 2. SCOPE, APPLICATION AND TIME REQUIREMENTS.

2.1 Application of Elective Transmission Upgrade Interconnection Procedures.

The ETU IP and ETU IA shall apply to Interconnection Requests pertaining to Elective Transmission Upgrades. Except as expressly provided in the ETU IP and ETU IA, nothing in the ETU IP or ETU IA shall be construed to limit the authority or obligations that the Interconnecting Transmission Owner or System Operator, as applicable, has with regard to ISO New England Operating Documents.

2.2. Comparability.

The System Operator shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this ETU IP. The System Operator and Interconnecting Transmission Owner will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the ETU is owned by the Interconnecting Transmission Owner, its subsidiaries or Affiliates, or others.

2.3 Base Case Data.

System Operator, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, shall provide Base Case power flow, short circuit and stability databases, including all underlying assumptions, and contingency lists upon request to the Interconnection Customer and any third party consultant retained by the Interconnection Customer~~ or to any non-market affiliate~~. For the purpose of ~~the~~

~~Interconnection Customer.~~this provision, Base Case data may include the electromagnetic transient network model that does not include proprietary electromagnetic transient equipment models. The recipient(s) of such information shall be subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy as well as any other applicable requirement under Applicable Laws and Regulations regulating disclosure or confidentiality of such information. System Operator is permitted to require that the ~~third party consultant~~Interconnection Customer or ~~non-market affiliate~~third party consultant sign a confidentiality agreement before the release of information governed by Section 13.1 or the ISO New England Information Policy, or the release of any other information that is commercially sensitive or Critical Energy Infrastructure Information.~~ To the extent that any applicable information is not covered by any applicable confidentiality/disclosure requirements, such information may be provided directly to the Interconnection Customer.~~ Such databases and lists, hereinafter referred to as Base Cases, shall include all generation and transmission projects that are proposed for the New England Transmission System and any Affected System and for which a transmission expansion plan has been submitted and approved by the applicable authority and which, in the sole judgment of the System Operator, may have an impact on the Interconnection Request. The Interconnection Customer, where applicable, shall provide Base Case Data to the Interconnecting Transmission Owner and System Operator to facilitate required Interconnection Studies.

2.4 No Applicability to Transmission Service.

Nothing in this ETU IP shall constitute a request for, nor the provision of, any service except for Interconnection Service, including, but not limited to, transmission delivery service, local delivery service, distribution service, capacity service, energy service or Ancillary Services under any applicable tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

2.5 Treatment of Elective Transmission Upgrades for Transmission, Operations, and Scheduling Purposes.

All ETUs must be categorized as PTF, Non-PTF, MTF or OTF. External ETUs will be treated for transmission, operations and scheduling purposes by the System Operator in a manner consistent with similarly situated PTF, Non-PTF, MTF or OTF under the Tariff. Internal ETUs will be operated and scheduled by the System Operator without recognition of physical transmission rights.

2.6 Time Requirements.

Parties that must perform a specific obligation under a provision of the ETU IP or ETU IA within a specified time period shall use Reasonable Efforts to complete such obligation within the applicable time

period. A Party may, in the exercise of reasonable discretion and within the time period set forth by the applicable procedure or agreement, request that the relevant Party consent to a mutually agreeable alternative time schedule, such consent not to be unreasonably withheld.

SECTION 3. INTERCONNECTION REQUESTS.

3.1 General.

To initiate an Interconnection Request, an Interconnection Customer must comply with all of the requirements set forth in Section 3.3.1. The Interconnection Customer shall submit a separate Interconnection Request(s) for each Elective Transmission Upgrade of a: (a) specific technology to be interconnected at a designated Point of Interconnection for a specific capability; or (b) specific objective to facilitate the operation of specific Generating Facility(ies), including achieving CNR Interconnection Service, to increase transfer capability between two specific endpoints, or another specific and clearly defined discrete objective that the ISO, at its sole discretion, determines that it is appropriate to propose in a single Interconnection Request. The Interconnection Customer must comply with the requirements specified in Section 3.3.1 for each Interconnection Request even when more than one request is submitted.

Within three (3) Business Days after its receipt of a valid Interconnection Request, System Operator shall submit a copy of the Interconnection Request to Interconnecting Transmission Owner.

At Interconnection Customer's option, System Operator, Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point(s) of Interconnection to be studied no later than the execution of the Interconnection Feasibility Study Agreement, or the Interconnection System Impact Study Agreement if the Interconnection Customer elects not to pursue the Interconnection Feasibility Study.

All deposits that must be submitted to the System Operator under this ETU IP, must be delivered to the System Operator by electronic transfer within the period specified in the respective provision.

associated with the extended Commercial Operation Date. The Long Lead Facility will be modeled in the Base Cases for the CNR Study Group associated with the near term Forward Capacity Auction unless that CNR Study Group is underway, in which case the Long Lead Facility will be modeled in the next CNR Study Group.

3.2.3.3 Critical Path Schedule and Deposits for Long Lead Facility Treatment.

At the time an Interconnection Customer submits an election or request for Long Lead Facility treatment, the Interconnection Customer must submit, together with the request:

(1) Critical Path Schedule. A critical path schedule, in writing, for the Long Lead Facility (with a development cycle that would not be completed until after the beginning of the Capacity Commitment Period associated with the next Forward Capacity Auction (after the election for the Long Lead Facility is made) that meets the requirements set forth in Section III.13.1.1.2.2.2 of the Tariff. The Interconnection Customer must submit annually, in writing, an updated critical path schedule to the System Operator by the closing deadline of each New Capacity Show of Interest Submission Window that precedes the Forward Capacity Auction associated with the Capacity Commitment Period by which the Long Lead Facility is expected to have achieved Commercial Operation, prior to the inclusion of the Long Lead Facility in the Base Case for the CNR Group Study associated with the corresponding New Capacity Show of Interest Submission Window. With its annual update, for each critical path schedule milestone achieved since the submission of the previous critical path schedule update, the Interconnection Customer must include in the critical path update documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule.

(2) Long Lead Facility Deposits.

(a) Deposits. In addition to the deposits required elsewhere in the LGIP in the case of a Generating Facility or the ETUP IP for External ETU, at the time of its request for Long Lead Facility treatment, in accordance with Section 3.2.3.3, and by each deadline for which a New Generating Capacity Resource is required to provide financial assurance under Section III.13.1.9.1 of the Tariff, the Interconnection Customer must provide a separate deposit in the amount of 0.25*(Forward Capacity Auction Starting Price~~/~~ ($/kW-mo)/2)*requested CNR Capability or CNI Capability. For each calculation of the deposit, the System Operator shall use the Forward Capacity Auction Starting Price in effect for the upcoming Forward Capacity

Forward Capacity Auction. In such instance, the Interconnection Customer shall receive a refund from the System Operator of the Long Lead Facility deposits (with interest to be calculated in accordance with Section 3.6) as adjusted pursuant to 3.2.3.3(2), if appropriate, and from the Interconnecting Transmission Owner a refund of the payments for the upgrades that exceed the costs incurred by the Interconnecting Transmission Owner. If the Interconnection Customer withdraws only its election or request for Long Lead Facility treatment, such withdrawal will be considered a Material Modification and the Long Lead Facility will lose its Queue Position unless its withdrawal occurs within one of the thirty (30)-day periods described in Section 3.2.3.3(2) of the LGIP in the case of a Generating Facility or the ETU IP for an External ETU.

3.2.3.5 Additional Requirements to Maintain Long Lead Facility Treatment.

An Interconnection Customer with a Long Lead Facility must begin payment as required by the transmission expenditure schedule for the transmission upgrade costs that have been identified in the pertinent Interconnection Studies. The Interconnection Request for CNI Interconnection Service shall be deemed withdrawn under Section 3.6 if the Interconnection Customer fails to comply with the requirements for Long Lead Facility treatment, including the milestones specified in Section 3.2.1.4. In this circumstance, the conditions specified in an Interconnection Agreement for a Generating Facility seeking CNR Interconnection Service or External ETU seeking CNI Interconnection Service that had an Interconnection Request of a Queue Position lower than the Long Lead Facility, but cleared (in the case of the Elective Transmission Upgrade, the Import Capacity Resource) in a Forward Capacity Auction prior to the Long Lead Facility, shall be removed.

3.2.3.6 Participation in Earlier Forward Capacity Auctions.

An Interconnection Customer with a Long Lead Facility may, without loss of Queue Position, elect to participate in an earlier Forward Capacity Auction than originally anticipated, but only if the election to accelerate is made to the System Operator in writing within thirty (30) Calendar Days of the Scoping Meeting or within thirty (30) Calendar Days of the completion of the System Impact Study (but before the Long Lead Facility and the results of the associated System Impact Study are incorporated into the Base Cases). Otherwise, such an election shall be considered a Material Modification.

3.3 Valid Interconnection Request.

3.3.1 Initiating an Interconnection Request.

To initiate an Interconnection Request, Interconnection Customer must submit all of the following to the System Operator in the manner specified in Appendix 1 Interconnection Request to this ETU IP: (i) an initial deposit of $50,000, (ii) a completed application in the form of Appendix 1, (iii) all information and deposits required under Section 3.2, and (iv) demonstration of Site Control or a posting of an additional deposit of $10,000 in lieu of Site Control for all Interconnection Request except those requesting CNI Interconnection Service, in which case Site Control is required. Interconnection Customer does not need to demonstrate Site Control where the Interconnection Request is for (i) a modification to the Interconnection Customer's existing Pool Transmission Facility, Merchant Transmission Facility, or Other Transmission Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the modification proposed in the Interconnection Request does not require additional real property, or (ii) a modification to existing Pool Transmission Facility that is not owned by the Interconnection Customer. The portions of the deposit of $50,000 that have not been applied as provided in this Section 3.3.1 shall be refundable if (i) the Interconnection Customer withdraws the Interconnection Request, pursuant to Section 3.6, within ten (10) Business Days of the Scoping Meeting, or (ii) if the Interconnection Customer executes an ETU IA. Otherwise, any unused balance of the deposit of $50,000 shall be non-refundable and applied on a pro-rata basis to offset costs incurred by Interconnection Customers with lower Queue Positions that are subject to re-study, as determined by the System Operator in accordance with the provisions of this ETU IP, as a result of the withdrawal of an Interconnection Request with a higher Queue Position.

The deposit of $50,000 shall be applied toward the costs incurred by the System Operator associated with the Interconnection Request and Long Lead Facility treatment, as well as, the costs of the Interconnection Feasibility Study and/or the Interconnection System Impact Study, including the cost of developing the study agreements and their attachments, and the cost of developing the ETU IA.

If, in the case of a request that is not for CNI Interconnection Service, the Interconnection Customer demonstrates Site Control within the cure period specified in Section 3.3.3 after submitting its Interconnection Request, the additional deposit of $10,000 shall be refundable; otherwise, that deposit shall be applied as provided in Section 3.1, including, toward the costs of any Interconnection Studies pursuant to the Interconnection Request, the cost of developing the study agreement(s) and associated attachment(s), and the cost of developing the ETU IA.

The expected Trial Operation Date of the new Elective Transmission Upgrade, or the increase in capability of an existing Pool Transmission Facility, Merchant Transmission Facility or Other

Interconnection Request does not constitute a valid request. Interconnection Customer shall provide the System Operator the additional requested information needed to constitute a valid request within ten (10) Business Days after receipt of such notice. Failure by Interconnection Customer to comply with this Section 3.3.3 shall be treated in accordance with Section 3.6.

3.3.4 Scoping Meeting.

Within ten (10) Business Days after receipt of a valid Interconnection Request, System Operator shall establish a date agreeable to Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, for a Scoping Meeting, and such date shall be no later than thirty (30) Calendar Days from receipt of the valid Interconnection Request, unless otherwise mutually agreed upon by the Parties.

The purpose of the Scoping Meeting shall be (i) to discuss the estimated timeline for completing all applicable Interconnection Studies, and alternative interconnection options, (ii) to exchange pertinent information including any transmission data that would reasonably be expected to impact such interconnection options, (iii) to analyze such information, (iv) to determine the potential feasible Points of Interconnection, and (v) to discuss any other information necessary to facilitate the administration of the Interconnection Procedures. If a PSCAD model is required, the Parties shall discuss this at the Scoping Meeting. If the Interconnection Customer provided the technical data called for in Appendix 1, Attachment A with the Interconnection Request, the Parties shall discuss the detailed project design at the Scoping Meeting.

The Parties will bring to the meeting such technical data, including, but not limited to: (i) general facility loadings, (ii) general instability issues, (iii) information regarding general short circuit issues, (iv) general voltage issues, and (v) general reliability issues as may be reasonably required to accomplish the purpose of the meeting. The Parties will also bring to the meeting personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Interconnection Customer shall designate its Point of Interconnection, pursuant to Section 6.1, and one or more available alternative Point(s) of Interconnection. The duration of the meeting shall be sufficient to accomplish its purpose.

Within five (5) Business Days following the Scoping Meeting Interconnection Customer shall notify the System Operator, in writing, (i) whether it wants the Interconnection Feasibility Study to be completed as

a separate and distinct study or as part of the Interconnection System Impact Study; (ii) if requesting the Interconnection Feasibility Study be completed as a separate and distinct study, which of the alternative study scopes is being selected pursuant to Section 6.2; and (iii) the Point(s) of Interconnection and any reasonable alternative Point(s) of Interconnection for inclusion in the attachment to the Interconnection Feasibility Study Agreement, or the Interconnection System Impact Study Agreement if the Interconnection Customer elects not to pursue the Interconnection Feasibility Study.

3.4 OASIS Posting.

The System Operator will maintain on its OASIS a list of all Interconnection Requests in its Control Area. The list will identify, for each Interconnection Request: (i) the maximum net summer and winter megawatt electrical output; (ii) the location by county and state of the Point of Interconnection; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected Trial Operation Date; (v) the status of the Interconnection Request, including Queue Position; (vi) the type of Interconnection Service being requested (i.e., CNI Interconnection Service or NI Interconnection Service); and (vii) the availability of any studies related to the Interconnection Request; (viii) the date of the Interconnection Request; (ix) the type of Elective Transmission Upgrade to be constructed (e.g., Internal ETU, External ETU, controllable, non-controllable); and (x) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed. Except in the case of an Affiliate, the list will not disclose the identity of the Interconnection Customer until the Interconnection Customer executes an ETU IA or requests that the System Operator and Interconnecting Transmission Owner jointly file an unexecuted ETU IA with the Commission. Before participating in a Scoping Meeting with an Interconnection Customer that is also an Affiliate, the Interconnecting Transmission Owner shall post on OASIS an advance notice of its intent to do so. The System Operator shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Optional Interconnection Study reports shall be posted to the System Operator's OASIS site subsequent to the meeting between the System Operator, Interconnecting Transmission Owner, and Interconnection Customer to discuss the applicable study results. The System Operator shall also post any known deviations in the Elective Transmission Upgrade's Trial Operation Date.

3.5 Coordination with Affected Systems.

The System Operator will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected Parties and, if possible, include those results (if available) in its applicable Interconnection Study within the time frame specified in this ETU IP. The System Operator will include such Affected Parties in all meetings held with the Interconnection

The System Operator shall update the OASIS Queue Position posting. Except as otherwise provided elsewhere in this ETU IP, the System Operator and the Interconnecting Transmission Owner shall arrange to refund to the Interconnection Customer any portion of the Interconnection Customer's deposit or study payments that exceeds the costs incurred, including interest calculated in accordance with section 35.19a(a)(2) of the Commission's regulations, or arrange to charge to the Interconnection Customer any amount of such costs incurred that exceed the Interconnection Customer's deposit or study payments, including interest calculated in accordance with section 35.19a(a)(2) of the Commission's regulations. In the event of such withdrawal, System Operator, subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information, shall provide, at Interconnection Customer's request, all information developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

SECTION 4. QUEUE POSITION.

4.1 General.

System Operator shall assign a Queue Position based upon the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form in Appendix 1 to this ETU IP, and Interconnection Customer provides such information in accordance with Section 3.3.3, then System Operator shall assign Interconnection Customer a Queue Position based on the date the application form was originally filed. ~~A Material Modification pursuant to Section 4.4.2 shall be treated in accordance with Section 4.4.~~

Except as otherwise provided in this Section 4.1, the Queue Position of each Interconnection Request will be used to determine: (i) the order of performing the Interconnection Studies; (ii) the order in which Interconnection Requests for CNR Interconnection Service and CNI Interconnection Service will be included in the CNR Group Study; and (iii) the cost responsibility for the facilities and upgrades necessary to accommodate the Interconnection Request. A higher queued Interconnection Request is one that has been placed "earlier" in the queue in relation to another Interconnection Request that is lower queued.

4.1.1 Order of Interconnection Requests in the CNR Group Study.

and upgrades associated with an overlapping CNR Interconnection Service or CNI Interconnection Service Interconnection Request having a higher Queue Position if the Conditional Qualified New Resource obtains a Capacity Supply Obligation through a Forward Capacity Auction under Section III.13.2.5 of the Tariff.

An Interconnection Customer with a lower queued CNR Interconnection Service Interconnection Request for a Generating Facility or CNI Interconnection Service Interconnection Request for an Elective Transmission Upgrade that has achieved Commercial Operation and obtained CNR Interconnection Service or CNI Interconnection Service, respectively, may be responsible for additional facilities and upgrades if the related higher queued CNR Interconnection Service or CNI Interconnection Service Interconnection Request for a Long Lead Facility achieves Commercial Operation and obtains CNR Interconnection Service or CNI Interconnection Service, respectively. In such circumstance, Appendix A to the Interconnection Agreement for the lower queued CNR Interconnection Service or CNI Interconnection Service Interconnection Request shall specify the facilities and upgrades for which the Interconnection Customer shall be responsible if the higher queued CNR Interconnection Service or CNI Interconnection Service Interconnection Request for a Long Lead Facility achieves Commercial Operation and obtains CNR Interconnection Service or CNI Interconnection Service, respectively.

4.2 Reserved.

4.3 Transferability of Queue Position.

An Interconnection Customer may transfer its Queue Position to another entity only if such entity acquires the specific Elective Transmission Upgrade identified in the Interconnection Request and the Point of Interconnection does not change. The Interconnection Customer must notify the System Operator, in writing, of any transfers of Queue Position and must provide the System Operator with the transferee's contact information, and System Operator shall notify Interconnecting Transmission Owner and any Affected Parties of the same.

4.4 Modifications.

The Interconnection Customer shall submit to System Operator and Interconnecting Transmission Owner, in writing, modifications to any information provided in the Interconnection Request, including its attachments. The Interconnection Customer shall retain its Queue Position if the modifications are in accordance with Sections 4.4.1 or 4.4.4, or are determined not to be Material Modifications pursuant to Section 4.4.2. The System Operator will notify the Interconnecting Transmission Owner, and, when

System Operator deems it appropriate in accordance with applicable codes of conduct and confidentiality requirements, it will notify any Affected Party of such modifications.

A new Interconnection Request shall be required to: (1) increase the capability of an Elective Transmission Upgrade above that specified in an Interconnection Request, or an existing Interconnection Agreement (whether executed or filed in unexecuted form with the Commission); (2) change from NI Interconnection Service to CNI Interconnection Service, in which case a new Interconnection Request for CNI Interconnection Service shall be required; or (3) change the objective specified in an Interconnection Request. Such new Interconnection Request will receive the lowest Queue Position available at the time the Interconnection Request is submitted for purposes of cost allocation and study analysis. Notwithstanding the foregoing, an Interconnection Customer with an Interconnection Request for CNI Interconnection Service has until the Forward Capacity Auction for which the associated Capacity Commitment Period begins less than seven (7) years (or the years agreed to pursuant to Section 3.3.1 or Section 4.4.5) from the date of the original Interconnection Request for CNI Interconnection Service for an Import Capacity Resource(s) associated with its Elective Transmission Upgrade to clear the entire megawatt amount for which CNI Interconnection Service was requested. A new Interconnection Request for CNI Interconnection Service will be required for the Elective Transmission Upgrade to enable the participation of an Import Capacity Resource in any subsequent auctions.

During the course of the Interconnection Studies, either the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes do not constitute a Material Modification and are acceptable to the Parties, such acceptance not to be unreasonably withheld, System Operator and the Interconnecting Transmission Owner shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 6.4, Section 7.6 and Section 8.5 as applicable and Interconnection Customer shall retain its Queue Position.

4.4.1 Prior to the commencement ~~return~~ of the ~~executed~~ Interconnection System Impact Study ~~Agreement to System Operator~~, modifications permitted under this Section shall include specifically: (a) a decrease of up to 60 percent in the capability of the proposed project; (b) modifying the technical

relates or any extension of a duration that results in the Trial Operation Date exceeding the date the Interconnection Request was received by the System Operator by seven (7) or more years is a Material Modification unless the Interconnection Customer demonstrates to the System Operator due diligence in pursuit of permitting, licensing and construction of the Elective Transmission Upgrade to meet the Commercial Operation Date, In-Service Date or Trial Operation Date provided in the Interconnection Request. Such demonstration shall be based on evidence to be provided by the Interconnection Customer of accomplishments in permitting, licensing, and construction in an effort to meet the Commercial Operation Date, In-Service Date or Trial Operation Date provided in this Interconnection Request. Such evidence may include filed documents, records of public hearings, governmental agency findings, documentation of actual construction progress, including the previous four (4) months. If the evidence demonstrates that the Interconnection Customer did not undertake reasonable efforts to meet the Commercial Operation Date, In-Service Date or Trial Operation Date specified in the Interconnection Request, or demonstrates that reasonable efforts were not undertaken until four (4) months prior to the request for extension, the request for extension shall constitute a Material Modification. The Interconnection Customer may then withdraw the proposed Material Modification or proceed with a new Interconnection Request for such modification.

SECTION 5. PROCEDURES FOR TRANSITION.

5.1 Rules for Establishing Queue Position for Interconnection Requests Pending ~~Requests~~Prior to February 16, 2015.

5.1.1 An Interconnection Customer with a request for Elective Transmission Upgrade submitted prior to February 16, 2015, shall be assigned a Queue Position pursuant to the following provisions.

5.1.1.1 If the Interconnection Customer's Elective Transmission Upgrade has received an approval pursuant to Section I.3.9 of the Tariff prior to February 16, 2015:

5.1.1.1.1 The Interconnection Request shall be assigned a Queue Position based on the date of the Elective Transmission Upgrade's approval pursuant to Section I.3.9 of the Tariff and shall be respected by all Interconnection Requests with a lower Queue Position than the Elective Transmission Upgrade's assigned Queue Position. The assigned Queue Position for an Interconnection Request of an External ETU that is a controllable Merchant Transmission Facility or Other Transmission Facility shall be for NI Interconnection Service. Within sixty (60) days from February 16, 2015, the Interconnection Customer

~~**5.2 Reserved.**~~

5.2 Transition Rules for Pending Interconnection Requests After February 16, 2015.

5.2.1 Any Interconnection Customer assigned a Queue Position prior to [Effective Date], shall retain that Queue Position subject to Section 4.4 of this ETU IP.

5.2.1.1 If an Interconnection Study Agreement has not been executed prior to [Effective Date], then such Interconnection Study, and any subsequent Interconnection Studies, shall be processed in accordance with the version of this ETU IP in effect on [Effective Date] (or as revised thereafter).

5.2.1.2 If an Interconnection Study Agreement has been executed prior to [Effective Date] and is actively under study, such Interconnection Study shall be completed in accordance with the terms of such agreement. If an Interconnection Study Agreement has been executed prior to [Effective Date], but the Interconnection Study has not commenced, such Interconnection Study shall be completed, and any subsequent Interconnection Studies shall be processed, in accordance with the version of the ETU IP in effect on [Effective Date]. If the Interconnection Study has not commenced, within sixty (60) Calendar Days from ~~the~~ [Effective Date], Interconnection Customer shall submit an updated Interconnection Request together with completed attachments and models required therein to facilitate the System Operator, in coordination with Interconnecting Transmission Owner and Affected Party as deemed appropriate by the System Operator, conduct of the Interconnection Study. Updates to the Interconnection Request and attachments thereto will be subject to review pursuant to Section 4.4 of this ETU IP. Notwithstanding any other provision in this ETU IP, if the Interconnection Customer fails to meet these requirements within a period not to exceed sixty (60) Calendar Days, the Interconnection Request shall be deemed withdrawn.

5.2.2 Transition Period. To the extent necessary, the System Operator, Interconnection Customers with an outstanding Interconnection Request (i.e., an Interconnection Request for which an ETU IA has neither been executed nor submitted to the Commission for approval prior to [Effective Date]), Interconnecting Transmission Owner and any other Affected Parties, shall transition to proceeding under the version of the ETU IP in effect as of [Effective Date] (or as revised thereafter) within a reasonable period of time not to exceed sixty (60) Calendar Days. The use of the term "outstanding Interconnection Request" herein shall mean any Interconnection Request, on [Effective Date]: (i) that has been submitted, together with the required deposit and attachments, but not yet accepted by the System Operator; (ii) where the related ETU IA has not yet been submitted to the Commission for approval in executed or unexecuted form, (iii)

where the relevant Interconnection Study Agreements have not yet been executed, or (iv) where any of the relevant Interconnection Studies are in process but not yet completed. Any Interconnection Customer with an outstanding Interconnection Request as of the effective date of this ETU IP may request a reasonable extension of the next applicable deadline if necessary to avoid undue hardship or prejudice to its Interconnection Request. A reasonable extension, not to exceed sixty (60) Calendar Days, shall be granted by the System Operator to the extent consistent with the intent and process provided for under this ETU IP.

5.3 New System Operator or Interconnecting Transmission Owner.

If the System Operator transfers operational control of the New England Transmission System to a successor System Operator during the period when an Interconnection Request is pending, the System Operator shall transfer to the successor System Operator any amount of the deposit or payment with interest thereon that exceeds the cost that it incurred to evaluate the request for interconnection. Any difference between such net amount and the deposit or payment required by this ETU IP shall be paid by or refunded to the Interconnection Customer, as appropriate. The System Operator shall coordinate with the successor System Operator to complete any Interconnection Study, as appropriate, that the System Operator has begun but has not completed.

If the Interconnecting Transmission Owner transfers ownership of its transmission facilities to a successor transmission owner during the period when an Interconnection Request is pending, and System Operator in conjunction with Interconnecting Transmission Owner has tendered a draft ETU IA to the Interconnection Customer but the Interconnection Customer has not either executed the ETU IA or requested the filing of an unexecuted ETU IA with the Commission, unless otherwise provided, the Interconnection Customer must complete negotiations with the successor transmission owner.

SECTION 6. INTERCONNECTION FEASIBILITY STUDY.

6.1 Interconnection Feasibility Study Agreement.

The Interconnection Customer has the option to request either that the Interconnection Feasibility Study be completed as a separate and distinct study under this Section 6, or as part of the Interconnection System Impact Study under Section 7. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 6 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 6 are performed as part of

Operator shall notify the Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection Feasibility Study Agreement and the Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed Interconnection Feasibility Study Agreement or deposit.

If the Interconnection Feasibility Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting, a substitute Point of Interconnection identified by the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, and acceptable to the Parties, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and re-studies shall be completed pursuant to Section 6.4 as applicable. For the purpose of this Section 6.1, if the Parties cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement, as specified pursuant to Section 3.3.4, shall be the substitute.

6.2 Scope of Interconnection Feasibility Study.

The Interconnection Feasibility Study shall preliminarily evaluate the feasibility of the proposed interconnection to the Administered Transmission System with available data and information. ~~The Interconnection Feasibility Study does not require detailed model development.~~

The Interconnection Feasibility Study will consider the ~~base case~~Base Case as well as all generating facilities and Elective Transmission Upgrades (and with respect to (iii), any identified Network Upgrades) that, on the date the Interconnection Feasibility Study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request; and (iv) have no Queue Position but have executed an Interconnection Agreement or requested that an unexecuted Interconnection Agreement be filed with the Commission~~.~~ (the "Study Case" for the Interconnection Feasibility Study). An Interconnection Customer with a CNI Interconnection Service Interconnection Request may also request that the Interconnection Feasibility Study include a preliminary, non-binding, analysis to identify potential upgrades that may be necessary for the Elective Transmission Upgrade to enable an Import Capacity Resource(s) to qualify for participation in a Forward

Capacity Auction under Section III.13 of the Tariff, based on a limited set of assumptions to be specified by the Interconnection Customer and reflected in Attachment A to the Interconnection Feasibility Study Agreement. The Interconnection Feasibility Study will consist of a power flow, including thermal analysis and voltage analysis, and short circuit analysis. The Interconnection Feasibility Study report will provide (i) a list of facilities, and a non-binding good faith estimate of cost responsibility; (ii) a non-binding good faith estimated time to construct the Interconnection Facilities and Network Upgrades; (iii) a protection assessment to determine the required Interconnection Facilities; and may provide (iv) an evaluation of the siting of Interconnection Facilities and Network Upgrades; and (v) identification of the likely permitting and siting process including easements and environmental work for Interconnection Facilities and Network Upgrades. Alternatively, in the case where the Interconnection Customer requests that the Interconnection Feasibility Study be completed as a separate and distinct study, the Interconnection Customer may provide the technical data called for in Appendix 1, Attachment A with the executed Interconnection Feasibility Study Agreement and request that the Interconnection Feasibility Study consist of limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient analysis, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Elective Transmission Upgrade's interconnection given recent study experience and as discussed at the Scoping Meeting. In this case, the Interconnection Feasibility Study report will provide (i) the study findings; and, (ii) a preliminary description of and ~~, to the extent readily available to the Interconnecting Transmission Owner,~~ a non-binding good faith order of magnitude estimated cost of (unless such cost estimate is waived by the Interconnection Customer)~~estimated cost of~~ and the time to construct the Interconnection Facilities and Network Upgrades necessary to interconnect the Elective Transmission Upgrade as identified within the scope of the analysis performed as part of the study. To the extent the Interconnection Customer requested a preliminary analysis as described in this Section 6.2, the Interconnection Feasibility Study report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Elective Transmission Upgrade to enable an Import Capacity Resource(s) to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

6.3 Interconnection Feasibility Study Procedures.

The System Operator in coordination with Interconnecting Transmission Owner shall utilize existing studies to the extent practicable when it performs the study. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the Interconnection Feasibility Study no later than forty-five (45) Calendar Days after System Operator and Interconnecting Transmission Owner receive the fully executed Interconnection Feasibility Study Agreement, study deposit and required

technical data in accordance with Section 6.1. At the request of the Interconnection Customer or at any time the System Operator or the Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection Feasibility Study, the System Operator shall notify the Interconnection Customer as to the schedule status of the Interconnection Feasibility Study. If the System Operator is unable to complete the Interconnection Feasibility Study within that time period, the System Operator shall notify the Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. ~~Upon~~In such circumstances, upon request, the System Operator with input from the Interconnecting Transmission Owner shall provide all supporting documentation, workpapers and relevant ~~pre-Interconnection Request and post-Interconnection Request~~Study Case power flow and short circuit databases that have been developed for the Interconnection Feasibility Study to any third party consultant retained by the Interconnection Customer ~~or to any non-market affiliate of the Interconnection Customer~~. The recipient(s) of such information shall be subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information. To the extent that any applicable information is not covered by any applicable confidentiality/disclosure requirements, such information may be provided directly to the Interconnection Customer.

6.3.1 Meeting with Parties.

Within ten (10) Business Days of providing an Interconnection Feasibility Study report to the Interconnection Customer, the System Operator will convene a meeting of the Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements to discuss the results of the Interconnection Feasibility Study.

6.4 Re-Study.

If re-study of the Interconnection Feasibility Study is required due to (i) a higher queued project dropping out of the queue, (ii) a modification of a higher queued project subject to Section 4.4, (iii) a re-designation of the Point of Interconnection pursuant to Section 6.1, (iv) a re-assessment of the upgrade responsibilities of an Elective Transmission Upgrade associated with an Import Capacity Resource(s) or a Generating Facility after the Import Capacity Resource(s) or the Generating Facility receives a Capacity Supply Obligation in accordance with Section III.13 of the Tariff, or (v) a modification to a transmission project included in the Base Case, the System Operator shall notify the Interconnection Customer and Interconnecting Transmission Owner in writing. Each re-study shall be conducted serially based on the

Queue Position of each Interconnection Customer, and each re-study shall take not longer than sixty (60) Calendar Days from the date the re-study commences. Any cost of re-study shall be borne by the Interconnection Customer being re-studied. If the original Interconnection Feasibility Study is complete and the final invoice has been issued, the re-study shall be performed under a new Interconnection Feasibility Study Agreement.

The Interconnection Customer shall have the option to waive the re-study and elect to have the re-study performed as part of its Interconnection System Impact Study. The Interconnection Customer shall provide written notice of the waiver and election of moving directly to the Interconnection System Impact Study within five (5) Business Days of receiving notice from the System Operator of the required re-study.

SECTION 7. INTERCONNECTION SYSTEM IMPACT STUDY.

7.1 Interconnection System Impact Study Agreement.

If the Interconnection Customer did not request that the Interconnection Feasibility Study be completed as a separate and distinct study, Section 6 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 6 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and the System Operator shall be responsible for generating only one final report, which will include the results of both Section 6 and Section 7.

Within five (5) Business Days following the Interconnection Feasibility Study results meeting, or subsequent to the Scoping Meeting within five (5) Business Days following the receipt of designation of the Point(s) of Interconnection and type of study to be performed pursuant to Section 3.3.4, if the Interconnection Customer did not request that the Interconnection Feasibility Study be completed as a separate and distinct study, the System Operator and Interconnecting Transmission Owner shall provide to Interconnection Customer the Interconnection System Impact Study Agreement, which includes a non-binding good faith estimate of the cost and timeframe for commencing and completing the Interconnection System Impact Study. The Interconnection System Impact Study Agreement shall provide that the Interconnection Customer shall compensate the System Operator and Interconnecting Transmission Owner for the actual cost of the Interconnection System Impact Study, including the cost of developing the study agreement and its attachment(s) and the cost of developing the ETU IA.

7.2 Execution of Interconnection System Impact Study Agreement.

The Interconnection Customer shall execute the Interconnection System Impact Study Agreement and deliver the executed Interconnection System Impact Study Agreement to the System Operator no later than thirty (30) Calendar Days after its receipt along with a demonstration of Site Control and the technical data called for in Appendix 1, Attachment A, and the Interconnection Customer shall also deliver ~~simultaneously~~ a refundable deposit. An Interconnection Customer does not need to demonstrate Site Control where the Interconnection Request is for (i) a modification to the Interconnection Customer's existing Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility and the Interconnection Customer has certified in the Interconnection Request that it has Site Control and that the modification proposed in the Interconnection Request does not require additional real property, or (ii) a modification of an existing Pool Transmission Facility that is not owned by the Interconnection Customer. If a PSCAD model was determined to be needed for the Elective Transmission Upgrade at the Scoping Meeting, then the Interconnection Customer shall have ninety (90) Calendar Days from the date of~~fo~~ the Scoping Meeting or the execution of the Sys~~ett~~em Impact Study Agreement (whichever is later) to provide the PSCAD model. The deposit for the study shall be the greater of 100 percent of the estimated cost of the study or $250,000.

The deposit shall be applied toward the cost of the Interconnection System Impact Study, including the cost of developing the study agreement and its attachment(s) and the cost of developing the ETU IA. Any difference between the study deposit and the actual cost of the Interconnection System Impact Study shall be paid by or refunded to the Interconnection Customer, except as otherwise provided in Section 13.3. In accordance with Section 13.3, the System Operator and/or the Interconnecting Transmission Owner shall issue to the Interconnection Customer an invoice for the costs of Interconnection System Impact Study that have been incurred by the System Operator and/or the Interconnecting Transmission Owner for the System Impact Study, including the study agreement and its attachment(s) and the ETU IA. If the Interconnection Customer elects the deposit described in (ii) above, the System Operator and the Interconnecting Transmission Owner may, in the exercise of reasonable discretion, invoice the Interconnection Customer on a monthly basis for the work to be conducted on the Interconnection System Impact Study on each month. The Interconnection Customer shall pay the invoiced amounts, to the extent such amounts are greater than the initial deposit, within thirty (30) Calendar Days of receipt of invoice. The System Operator shall continue to hold the amounts on deposit until settlement of the final invoice with the Interconnection Customer and the Interconnecting Transmission Owner.

On or before the return of the executed Interconnection System Impact Study Agreement to the System Operator and Interconnecting Transmission Owner, the Interconnection Customer shall provide the technical data called for in Appendix 1, Attachment A; provided that if a PSCAD model was determined to be needed at the Scoping Meeting, then the Interconnection Customer shall have ninety (90) Calendar Days from the execution of the System Impact Study Agreement to provide the PSCAD model.

If the Interconnection Customer does not provide all such technical data when it delivers the Interconnection System Impact Study Agreement, the System Operator shall notify the Interconnection Customer of the deficiency within five (5) Business Days of the receipt of the executed Interconnection System Impact Study Agreement and the Interconnection Customer shall cure the deficiency within ten (10) Business Days of receipt of the notice, provided, however, such deficiency does not include failure to deliver the executed Interconnection System Impact Study Agreement or deposit.

If the Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting or the Interconnection Feasibility Study, a substitute Point of Interconnection identified by the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, and acceptable to each Party, such acceptance not to be unreasonably withheld, will be substituted for the designated Point of Interconnection specified above without loss of Queue Position, and re-studies shall be completed pursuant to Section 7.6 as applicable. For the purpose of this Section 7.2, if the Parties cannot agree on the substituted Point of Interconnection, then Interconnection Customer may direct that one of the alternatives as specified in the Interconnection Feasibility Study Agreement or Interconnection System Impact Study depending on whether Interconnection Customer requested that the Interconnection Feasibility Study be completed as a separate and distinct study or as part of the Interconnection System Impact Study, as specified pursuant to Section 3.3.4, shall be the substitute.

7.3 Scope of Interconnection System Impact Study.

The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability and operation of the New England Transmission System. The Interconnection System Impact Study will consider the ~~base case~~Base Case as well as all generating facilities and Elective Transmission Upgrades (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Interconnection System Impact Study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are

interconnected to Affected Systems and may have an impact on the Interconnection Request; (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request; and (iv) have no Queue Position but have executed an Interconnection Agreement or requested that an unexecuted Interconnection Agreement be filed with the Commission. (the "Study Case" for the Interconnection System Impact Study). An Interconnection Customer with a CNI Interconnection Service Interconnection Request may also request that the Interconnection System Impact Study include a preliminary, non-binding, analysis to identify potential upgrades that may be necessary for the Interconnection Customer's Elective Transmission Upgrade to enable an Import Capacity Resource(s) to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff, based on a limited set of assumptions to be specified by the Interconnection Customer and reflected in Attachment A to the Interconnection System Impact Study Agreement.

The Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, a power flow analysis, including thermal analysis and voltage analysis, a system protection analysis and any other analyses, such as electromagnetic transient analysis, that are deemed necessary by the System Operator in consultation with the Interconnecting Transmission Owner. The Interconnection System Impact Study report will state the assumptions upon which it is based, state the results of the analyses, and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Interconnection System Impact Study report will provide (i) a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility; (ii) a non-binding good faith estimated time to construct; (iii) a protection assessment to determine the required protection upgrades; and may provide (iv) an evaluation of the siting of the Interconnection Facilities and Network Upgrades; and (v) identification of the likely permitting and siting process including easements and environment work. To the extent the Interconnection Customer requested a preliminary analysis as described in this Section 7.3, the Interconnection System Impact Study report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Elective Transmission Upgrade to enable an Import Capacity Resource(s) to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

7.4 Interconnection System Impact Study Procedures.

The System Operator shall coordinate the Interconnection System Impact Study with the Interconnecting Transmission Owner, and with any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, that is affected by the Interconnection Request pursuant to Section 3.5 above. The System Operator and Interconnecting Transmission Owner shall utilize existing studies to the extent practicable when it performs the study. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the Interconnection System Impact Study within ninety (90) Calendar Days after the receipt of the Interconnection System Impact Study Agreement, study deposit, demonstration of Site Control, if Site Control is required, and required technical data in accordance with Section 7.2.

At the request of the Interconnection Customer or at any time the System Operator or Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection System Impact Study, the System Operator shall notify the Interconnection Customer as to the schedule status of the Interconnection System Impact Study. If the System Operator and Interconnecting Transmission Owner are unable to complete the Interconnection System Impact Study within the time period, the System Operator shall notify the Interconnection Customer and provide an estimated start date if the study has not commenced and completion date with an explanation of the reasons why additional time is required. ~~Upon~~In such circumstances, upon request, the System Operator and Interconnecting Transmission Owner shall provide all supporting documentation, workpapers and relevant ~~pre-Interconnection Request and post-Interconnection Request~~Study Case power flow, short circuit and stability databases that have been developed for the Interconnection System Impact Study to any third party consultant retained by the Interconnection Customer~~ or to any non-market affiliate of the Interconnection Customer.~~. The recipient(s) of such information shall be subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information. To the extent that any applicable information is not covered by any applicable confidentiality/ disclosure requirements, such information may be provided directly to the Interconnection Customer.

The System Operator shall notify the Interconnection Customer when the Interconnection System Impact Study is expected to commence within sixty-five (65) Calendar Days. Interconnection Customer will be permitted to update the technical data provided in Appendix 1 and Attachment A, and submit modficiations to that technical data to the System Operator no later than sixty (60) Calendar Days from the date that the System Operator notified the Interconnection Customer ~~after receipt of the System Operator's notification~~ that the Interconnection System Impact Study is expected to commence. Such

modifications will not be deemed Material Modifications provided they meet the requirements of Section 4.4.1 of this ETU IP.

Where sufficient time has elapsed since the initial Scoping Meeting, within ten (10) Business Days after notifying the Interconnection Customer that the Interconnection System Impact Study is expected to commence, the System Operator may convene a second Scoping Meeting for the purpose of providing updated information to the Interconnection Customer in preparation for the submittal of updates to the technical data.

7.5 Meeting with Parties.

Within ten (10) Business Days of providing an Interconnection System Impact Study report to Interconnection Customer, the System Operator shall convene a meeting of the Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, to discuss the results of the Interconnection System Impact Study.

Within ~~five (5~~ten (10) Business Days following the study results meeting, the Interconnection Customer shall provide to the System Operator written notice that it will either pursue the Interconnection Facilities Study or waive the Interconnection Facilities Study and elect an expedited interconnection. If the Interconnection Customer waives the Facilities Study, it shall commit to the following milestones in the ETU IA: (i) Siting process and approval schedule for the Elective Transmission Upgrade and Interconnection Facilities; (ii) Engineering of Interconnection Facilities and Elective Transmission upgrade approved by Interconnecting Transmission Owner; (iii) Ordering of long lead time material for Interconnection Facilities and system upgrades; (iv) Trial Operation Date; and (v) Commercial Operation Date.

Within thirty (30) Calendar Days of the Interconnection Customer receiving the Interconnection System Impact Study report, the Interconnection Customer shall provide written comments on the report or written notice that it has no comments on the report. The System Operator shall issue a final Interconnection System Impact Study report within fifteen (15) Business Days of receiving the Interconnection Customer's comments or promptly upon receiving the Interconnection Customer's notice that it will not provide comments.

7.6 Re-Study.

or one hundred eighty (180) Calendar Days, if the Interconnection Customer requests a +/- 10 percent good faith cost estimate. Such cost estimates either individually or in the aggregate will be provided in the final study report.

At the request of the Interconnection Customer or at any time the System Operator or Interconnecting Transmission Owner determines that it will not meet the required time frame for completing the Interconnection Facilities Study, System Operator shall notify the Interconnection Customer, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, as to the schedule status of the Interconnection Facilities Study. If the System Operator is unable to complete the Interconnection Facilities Study and issue a draft Interconnection Facilities Study report within the time required, the System Operator shall notify the Interconnection Customer, Interconnecting Transmission Owner and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, and provide an estimated completion date and an explanation of the reasons why additional time is required.

The Interconnection Customer and appropriate Affected Parties may, within thirty (30) Calendar Days after receipt of the draft report, provide written comments to the System Operator and Interconnecting Transmission Owner, which the System Operator shall include in the final report. The System Operator shall issue the final Interconnection Facilities Study report within fifteen (15) Business Days of receiving the Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. The System Operator may reasonably extend such fifteen-day period upon notice to the Interconnection Customer if the Interconnection Customer's comments require the System Operator or Interconnecting Transmission Owner to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Report. ~~Upon~~In such circumstances, upon request, the System Operator and Interconnecting Transmission Owner shall provide the Interconnection Customer and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, or any third party consultant retained by the Interconnection Customer ~~or to any non-market affiliate of the Interconnection Customer~~ supporting documentation, with workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study. The recipient(s) of such information shall be subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information. To the extent that any applicable information is not covered by any

to provide transmission service or Interconnection Service based upon the results of the Optional Interconnection Study. The System Operator shall use Reasonable Efforts to coordinate the study with any Affected Systems that may be affected by the types of Interconnection Services that are being studied. The System Operator and Interconnecting Transmission Owner shall utilize existing studies to the extent practicable in conducting the Optional Interconnection Study.

The Optional Interconnection Study will consist of a short circuit analysis, a stability analysis, a power flow analysis, including thermal analysis and voltage analysis, a system protection analysis, and any other analyses that are deemed necessary by the System Operator in consultation with the Interconnecting Transmission Owner.

10.3 Optional Interconnection Study Procedures.

The executed Optional Interconnection Study Agreement, the prepayment, and technical and other data called for therein must be provided to the System Operator and Interconnecting Transmission Owner within ten (10) Business Days of the Interconnection Customer receipt of the Optional Interconnection Study Agreement. The System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to complete the Optional Interconnection Study within a mutually agreed-upon time period specified within the Optional Interconnection Study Agreement. If the System Operator and Interconnecting Transmission Owner are unable to complete the Optional Interconnection Study within such time period, the System Operator shall notify the Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required. ~~Upon~~In such circumstances, upon request, the System Operator and Interconnecting Transmission Owner shall provide the Interconnection Customer supporting documentation and workpapers and databases or data developed in the preparation of the Optional Interconnection Study to any third party consultant retained by the Interconnection Customer~~ or to any non-market affiliate of the Interconnection Customer.~~. The recipient(s) of such information shall be subject to the confidentiality provisions of Section 13.1 and the ISO New England Information Policy, as well as any other applicable requirement under Applicable Laws and Regulations regulating the disclosure or confidentiality of such information. To the extent that any applicable information is not covered by any applicable confidentiality/disclosure requirements, such information may be provided directly to the Interconnection Customer.

10.4 Meeting with Parties.

Within ten (10) Business Days of providing an Optional Interconnection Study report to Interconnection Customer, System Operator will convene a meeting of the Interconnecting Transmission Owner,

APPENDICES TO ETU IP

APPENDIX 1 INTERCONNECTION REQUEST FOR ELECTIVE TRANSMISSION UPGRADE

APPENDIX 2 INTERCONNECTION FEASIBILITY STUDY AGREEMENT

APPENDIX 3 INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

APPENDIX 4 INTERCONNECTION FACILITIES STUDY AGREEMENT

APPENDIX 5 OPTIONAL INTERCONNECTION STUDY AGREEMENT

APPENDIX 6 ELECTIVE TRANSMISSION UPGRADE INTERCONNECTION AGREEMENT

If yes, provide to ISO-NE, together with this Interconnection Request, the Long Lead Facility deposit and other required information as specified in Section 3.2.3 of the ETU IP, including a justification for Long Lead Facility treatment.

5) Evidence of Site Control *(check one)*:

a. ____If for CNI Interconnection Service, Site Control is included with this Interconnection Request form, as required.

b. ____If for NI Interconnection Service *(check one):*

i) ___Site Control is provided with this Interconnection Request form.

ii) ___In lieu of evidence of Site Control, a $10,000 deposit is provided with this Interconnection Request form (refundable within the cure period as described in Section 3.3.3 of the ETU IP).

iii) ___Site Control is not provided because the proposed modification is either: a) to existing MTF, OTF or PTF and by checking this option, the Interconnection Customer certifies that the proposed modification does not require additional real property, or b) to PTF and the Interconnection Customer does not own such PTF.

6) This Interconnection Customer requests *(check one):*

a. ___~~A~~An Interconnection Feasibility Study to be completed as a separate and distinct study, or

b. ___~~A~~An Interconnection System Impact Study with the Feasibility Study to be performed as the first step of the study.

c. If seeking CNI Interconnection Service, does the Interconnection Customer request a preliminary non-binding, analysis to identify potential upgrades that may be necessary to qualify resources for participation in a Forward Capacity Auction? ____Yes or ____No

Note: The above selection of a or b is not required as part of the initial Interconnection Request; however, the Interconnection Customer shall select either option and may revise this selection up to within five (5) Business Days following the Scoping Meeting.

7) The ETU technical data specified within the applicable attachment to this form *(check one):*

a. ____Is included with the submittal of this Interconnection Request.

b. **____Will be provided on or before the execution and return of the Feasibility Study Agreement (Attachment B) or the System Impact Study Agreement (Attachment A), as applicable.**

CUSTOMER INFORMATION

	Interconnection Customer	**Customer Representative**
Company Name:		
Address: (PO Box)		
(Street)		
(City, State, ZIP)		
Phone:		
FAX:		
Email:		

ISO Customer ID# (if available):_____

This Interconnection Request is submitted by:

Authorized Signature:_____ **Date:** _____

Name (type or print):_____

Title:_____

Company:_____

In order for an Interconnection Request to be considered a valid request, it must:

(a) Be accompanied by a deposit of $50,000.00, that is provided electronically and which may be refundable in accordance with Section 3.3.1 of the ETU IP;

(b) For CNI Interconnection Service, include documentation demonstrating Site Control. If for NI Interconnection Service, demonstrate Site Control or post an additional deposit of $10,000. If the Interconnection Customer with an Interconnection Request for NI Interconnection Service demonstrates Site Control within the cure period specified in Section 3.3.3 of the ETU IP, the additional deposit of $10,000 shall be refundable (An Interconnection Customer does not need to demonstrate Site Control for an Interconnection Request for a modification to its existing PTF, MTF or OTF facility where the Interconnection Customer has certified that it has Site Control and that the proposed modification does not require additional real property);

(c) Include a detailed map ~~(2 copies),~~, such as a map of the quality produced by the U.S. Geological Survey, which clearly indicates the site of the new facility and pertinent surrounding structures;

(d) Include a one-line diagram of the facilities (2 copies);

(e) Include all information required on the Interconnection Request form and any attachments thereto; and

(f) Include the deposit and all information required for Long Lead Facility treatment, if such treatment is requested in accordance with Section 3.2.3 of the ETU IP.

In addition, within sixty (60) days of submitting an Interconnection Request to the System Operator, the Interconnection Customer with a request for an External ETU, shall provide evidence that it has submitted a valid request with the other Control Area to which it seeks to interconnect.

All Interconnection Requests must be sent to the System Operator by any of the following methods:

By Mail to:	**By FAX to:**
ISO New England Inc.	**413 540-4203**
1 Sullivan Road	**Attention: Transmission Strategy & Services**
Holyoke MA 01040-2841	**By Email to:**
Attention: Transmission Strategy & Services	IRTT@iso-ne.com

Attachment A (page 8)
To Appendix 1
Interconnection Request
Technical Data Required For
Interconnection System Impact Study

Maximum converter station lagging reactive power supply (including filtering system) at the network side of the power transformer and at nameplate active power: Rectifier:_____ MVAr Inverter: _____MVar
Provide reactive capability curve.
DC transmission tower design illustrating tower type, conductor type, number of conductors, spacing between pole conductors or conductor bundles, and conductor or conductor bundle clearances.
DC cable design illustrating cable type, cable spacing, and underground or submarine installation design.
Pole conductor resistance at maximum operating temperature: _____ ohms
POWER SYSTEM SIMULATION MODELS
~~Update and delivery of all necessary, fully-functioning, non-proprietary or non-confidential, PSS/E models required for accurate steady-state, dynamic, and short-circuit simulation of the proposed Elective Transmission Upgrade facilities operation and performance within the bulk power system.~~Completed, fully-functioning, public (*i.e.*, non-proprietary or non-confidential) Siemens PTI's (PSS/E) power flow models or other compatible formats, such as IEEE and General Electric Company Power Systems Load Flows ("PSLF") data sheet, must be supplied with this Attachment A. If additional public data sheets are more appropriate to the proposed device-, then they shall be provided and discussed at the Scoping Meeting. For all Interconnection Studies commencing after January 1, 2017, all power flow models must be standard library models in PSS/E or applicable applications. After January 1, 2017, user-models will not be accepted. If a PSCAD model is deemed required at the Scoping Meeting, then the PSCAD model must be provided to the System Operator within ninety (90) Calendar Days of the Scoping Meeting date or the executed Interconnection System Impact Study Agreement (whichever is later). A benchmarking

analysis, consistent with the requirements in the ISO New England Planning Procedures, confirming acceptable performance of the PSS/E model in comparison to the PSCAD model, shall be provided at the time PSCAD model is submitted.
OTHER TRANSMISSION FACILITY DATA
System Operator and Interconnecting Transmission Owner reserve the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Facilities Study.

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Attachment A to the Interconnection Request is true and accurate.

For Interconnection Customer:_____ Date:_____

Attachment B (page 8)
To Appendix 1
Interconnection Request
Technical Data Required For
Interconnection Feasibility Study

Estimated maximum converter station lagging reactive power supply (including filtering system) at the network side of the power transformer and at nameplate active power: Rectifier:_____ MVAr Inverter:_____ MVAr
Provide reactive capability curve.
Conceptual DC transmission tower design illustrating tower type, conductor type, number of conductors, spacing between pole conductors or conductor bundles, and conductor or conductor bundle clearances.
Conceptual DC cable design illustrating cable type, cable spacing, and underground or submarine installation design.
Estimated pole conductor resistance at maximum operating temperature: _____ ohms
POWER SYSTEM SIMULATION MODELS
~~Delivery of all necessary~~Completed, fully-functioning, public (*i.e.*, non-proprietary or non-confidential~~,~~) Siemens PTI's (PSS/E) power flow models ~~required for accurate steady-state,~~or other compatible formats, such as IEEE and ~~short-circuit simulation of the~~ General Electric Company Power Systems Load Flows ("PSLF") data sheet, must be supplied with this Attachment A. If additional public data sheets are more appropriate to the proposed ~~Elective Transmission Upgrade facilities operation~~device, then they shall be provided and discussed at the Scoping Meeting. For all Interconnection Studies commencing after January 1, 2017, all power flow models must be standard library models in PSS/E or applicable applications. After January 1, 2017, user-models will not be accepted. If a PSCAD model is deemed required at the Scoping Meeting, then the PSCAD model must be provided to the System Operator within ninety (90) Calendar Days of the Scoping Meeting date or the executed Interconnection System Impact Study Agreement (whichever is later). A benchmarking analysis, consistent with the requirements in the ISO New England Planning Procedures, confirming

acceptable performance ~~within the bulk power system.~~of the PSS/E model in comparison to the PSCAD model, shall be provided at the time PSCAD model is submitted.
OTHER TRANSMISSION FACILITY DATA
System Operator and Interconnecting Transmission Owner reserve the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection System Impact Study.

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Attachment B to the Interconnection Request is true and accurate.

For Interconnection Customer:_____ Date:_____

APPENDIX 2

INTERCONNECTION FEASIBILITY STUDY AGREEMENT

THIS AGREEMENT is made and entered into this _____ day of _____, 20__ by and between _____, a _____ organized and existing under the laws of the State of _____ ("Interconnection Customer,") and ISO New England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System Operator"), and _____, a _____ organized and existing under the laws of the State of _____ ("Interconnecting Transmission Owner") [and _____, a _____ organized and existing under the laws of the State of _____ ("Interconnecting Transmission Owner")]. Interconnection Customer, System Operator, and Interconnecting Transmission Owner may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing an Elective Transmission Upgrade consistent with the Interconnection Request submitted by the Interconnection Customer dated _____; and

WHEREAS, Interconnection Customer desires to interconnect the Elective Transmission Upgrade to the Administered Transmission System; and

WHEREAS, Interconnection Customer has requested System Operator and Interconnecting Transmission Owner(s) to perform an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Elective Transmission Upgrade to the Administered Transmission System, and any Affected Systems.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the Commission-approved Elective Transmission Upgrade Interconnection Procedures ("ETU IP"), or in the other provisions of the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff").

2.0 Interconnection Customer elects and System Operator shall cause to be performed an Interconnection Feasibility Study consistent with Section 6.0 of the ETU IP in accordance with the Tariff.

3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection Feasibility Study shall be based on the technical information provided by Interconnection Customer in Attachment B to the Interconnection Request, as may be modified as the result of the Scoping Meeting. System Operator and Interconnecting Transmission Owner reserve the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with Section 3.3.4 of the ETU IP. If, after the designation of the Point of Interconnection pursuant to Section 3.3.4 of the ETU IP, Interconnection Customer modifies its Interconnection Request pursuant to Section 4.4, the time to complete the Interconnection Feasibility Study may be extended.

5.0 The Interconnection Feasibility Study report shall provide the following information depending on whether the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and shor circuit analysis or limited therma analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic analysis, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Elective Transmission Upgrade's interconnection given recent study experience and as discussed at the Scoping Meeting:

- preliminary identification of any circuit breaker or other facility short circuit capability limits exceeded as a result of the interconnection, or, findings of the limited thermal analysis, voltage analysis, short circuit analysis, stability analysis, and electromagnetic transient analysis, as appropriate, focusing on the issues that are expected to be the most significant for the proposed Elective Transmission Upgrade's interconnection given recent study experience and as discussed at the Scoping Meeting;

- preliminary identification of any thermal overload of any transmission facility or system voltage limit violations resulting from the interconnection, or, a preliminary description of and ~~, to the extent readily available to the Interconnecting Transmission Owner,~~ a non-binding good faith order of magnitude estimated cost of (unless such cost estimate is waived by the Interconnection Customer)~~estimated cost of~~ and the time to construct the Interconnection Facilities and Network Upgrades necessary to interconnect the Elective Transmission Upgrade as identified within the scope of the analysis performed as part of the study;
- If the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and short circuit analysis, initial review of grounding requirements and electric system protection;
- If the Feasibility Study consisted of a power flow, including thermal analysis and voltage analysis, and short circuit analysis, preliminary description and non-binding estimated cost of and the time to construct the facilities required to interconnect the Elective Transmission Upgrade to the Administered Transmission System and to address the identified short circuit and power flow issues; and
- to the extent the Interconnection Customer requested a preliminary analysis as described in this Section 6.2 of the ETU IP, the report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Elective Transmission Upgrade to enable an Import Capacity Resource(s) to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

  In accordance with the ETU IP, in performing the Interconnection Feasibility Study, System Operator and Interconnecting Transmission Owner shall coordinate with each other and Affected Parties, and shall receive and incorporate input from such entities into its study, and shall provide copies of the final study report to such entities.

6.0 The Interconnection Customer is providing ~~herewith~~ a deposit equal to 100 percent of the estimated cost of the study. The deposit shall be applied toward the cost of the Interconnection Feasibility Study and the development of this Interconnection Feasibility Study Agreement and its attachment(s). Interconnecting Transmission Owner's and

APPENDIX 3

INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

THIS AGREEMENT is made and entered into this _____ day of _____, 20__ by and between _____, a _____ organized and existing under the laws of the State of _____ ("Interconnection Customer,") and ISO New England Inc., a non-stock corporation existing under the laws of the State of Delaware ("System Operator"), and _____, a _____ organized and existing under the laws of the State of _____ ("Interconnecting Transmission Owner") [and _____, a _____ organized and existing under the laws of the State of _____ ("Interconnecting Transmission Owner")]. Interconnection Customer, System Operator, and Interconnecting Transmission Owner may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing an Elective Transmission Upgrade consistent with the Interconnection Request submitted by the Interconnection Customer dated _____; and

WHEREAS, Interconnection Customer desires to interconnect the Elective Transmission Upgrade to the Administered Transmission System;

WHEREAS, System Operator and Interconnecting Transmission Owner have completed an Interconnection Feasibility Study (the "Feasibility Study") and provided the results of said study to the Interconnection Customer, or Interconnection Customer has requested that the Feasibility Study be completed as part of the System Impact Study pursuant to Section 6.1 of the ETU IP, or in the other provisions of the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff")(This recital is to be omitted if Interconnection Customer has elected to forego the Interconnection Feasibility Study); and

WHEREAS, Interconnection Customer has requested System Operator and Interconnecting Transmission Owner to perform an Interconnection System Impact Study to assess the impact of interconnecting the Elective Transmission Upgrade to the Administered Transmission System, and any Affected Systems.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the Commission-approved Elective Transmission Upgrade Interconnection Procedure ("ETU IP").

2.0 Interconnection Customer elects and System Operator and Interconnecting Transmission Owner shall cause to be performed an Interconnection System Impact Study consistent with Section 7.0 of the ETU IP in accordance with the Tariff.

3.0 The scope of the Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection System Impact Study will be based upon the results of the Interconnection Feasibility Study, whether performed separately or as part of the Interconnection System Impact Study, and the technical information provided by Interconnection Customer in Attachment A to the Interconnection Request, subject to any modifications in accordance with Section 4.4 of the ETU IP. System Operator and Interconnecting Transmission Owner reserve the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection System Impact Study. If Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the Interconnection System Impact Study may be extended.

5.0 The Interconnection System Impact Study report shall provide the following information:

- identification of any circuit breaker or other facility short circuit capability limits exceeded as a result of the interconnection;
- identification of any thermal overload of any transmission facility or system voltage limit violations resulting from the interconnection;
- initial review of grounding requirements and electric system protection;

- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection;
- description and non-binding, good faith estimated cost of and the time to construct the facilities required to interconnect the Elective Transmission Upgrade to the Administered Transmission System and to address the identified short circuit, instability, and power flow issues; and
- to the extent the Interconnection Customer requested a preliminary analysis as described in this Section 7.4 of the ETU IP, the report will also provide a list of potential upgrades that may be necessary for the Interconnection Customer's Elective Transmission Upgrade to enable an Import Capacity Resource(s) to qualify for participation in a Forward Capacity Auction under Section III.13 of the Tariff.

6.0 The Interconnection Customer is providing ~~herewith~~ a deposit equal to the greater of 100 percent of the estimated cost of the Interconnection System Impact Study or $250,000.

The deposit shall be applied toward the cost of the Interconnection System Impact Study and the development of this Interconnection System Impact Study Agreement and its attachment(s) and the ETU IA. Interconnecting Transmission Owner's and System Operator's good faith estimate for the time of commencement and completion of the Interconnection System Impact Study is [insert date].

The total estimated cost of the performance of the Interconnection System Impact Study consists of $_____ which is comprised of the System Operator's estimated cost of $_____ and the Interconnecting Transmission Owner's estimated cost of $_____.

Any difference between the deposit and the actual cost of the Interconnection System Impact Study shall be paid by or refunded to the Interconnection Customer, as appropriate.

Upon receipt of the Interconnection System Impact Study, System Operator and Interconnecting Transmission Owner shall charge and the Interconnection Customer shall pay the actual costs of the Interconnection System Impact Study.

APPENDIX 6
ELECTIVE TRANSMISSION UPGRADE
INTERCONNECTION AGREEMENT

TABLE OF CONTENTS

Article 1	Definitions
Article 2	Effective Date, Term and Termination
Article 3	Regulatory Filings
Article 4	Scope of Service
Article 5	Interconnection Facilities Engineering, Procurement, and Construction
Article 6	Testing and Inspection
Article 7	Metering
Article 8	Communications
Article 9	Operations
Article 10	Maintenance
Article 11	Performance Obligation
Article 12	Invoice
Article 13	Emergencies
Article 14	Regulatory Requirements and Governing Law
Article 15	Notices
Article 16	Force Majeure
Article 17	Default
Article 18	Indemnity, Consequential Damages and Insurance
Article 19	Assignment
Article 20	Severability
Article 21	Comparability
Article 22	Confidentiality
Article 23	Environmental Releases
Article 24	Information Requirements
Article 25	Information Access and Audit Rights
Article 26	Subcontractors
Article 27	Disputes

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the NPCC and the New England Control Area, including publicly available local reliability requirements of Interconnecting Transmission Owners or other Affected Parties.

Base Case shall have the meaning specified in Section 2.3.

Base Case Data shall mean the Base Case power flow, short circuit, and stability databases used for the Interconnection Studies by the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Elective Transmission Upgrade Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Elective Transmission Upgrade Interconnection Agreement.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Capacity Capability Interconnection Standard ("CC Interconnection Standard") shall mean the criteria required to permit the Interconnection Customer to interconnect a Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility seeking Capacity Network Resource Interconnection Service or an Elective Transmission Upgrade seeking Capacity Network Import Interconnection Service, and in a manner that ensures intra-zonal deliverability by avoidance of the redispatch of other Capacity Network Resource or Elective Transmission Upgrades with Capacity Network Import Interconnection Service, as detailed in the ISO New England Planning Procedures.

Capacity Network Import Capability ("CNI Capability") shall mean, for an External Elective Transmission Upgrade that is a controllable Merchant Transmission Facility or Other Transmission Facility, the aggregate highest megawatt amount of Capacity Supply Obligation obtained by the Import

Capacity Resource(s) associated with the External Elective Transmission Upgrade, net of any megawatt reductions, in accordance with Section III.13 of the Tariff. The Capacity Network Import Capability shall be the maximum net megawatt electrical capability at the Point of Interconnection consistent with the Capacity Capability Interconnection Standard and shall not to exceed applicable seasonal equipment ratings determined pursuant to industry standards and consistent with the specifications described in ISO New England Planning and Operating Procedures.

Capacity Network Import Interconnection Service ("CNI Interconnection Service") shall mean, for an External Elective Transmission Upgrade that is a controllable Merchant Transmission Facility or Other Transmission Facility, the Interconnection Service selected by the Interconnection Customer to interconnect its Elective Transmission Upgrade with the Administered Transmission System in accordance with the Capacity Capability Interconnection Standard. An Interconnection Customer's Capacity Network Import Interconnection Service shall be for the megawatt of Capacity Network Import Capability. Capacity Network Import Interconnection Service does not in and of itself convey transmission service.

Capacity Network Resource Group Study ("CNR Group Study") shall mean the study performed by the System Operator under Section III.13.1.1.2.3 of the Tariff to determine which resources qualify to participate in a Forward Capacity Auction.

Commercial Operation shall mean the status of an Elective Transmission Upgrade that has commenced transmitting electricity, excluding performance during Trial Operation.

Commercial Operation Date shall mean the date on which the Elective Transmission Upgrade commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Elective Transmission Upgrade Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise. Confidential Information shall include, but not be limited to, information that is confidential pursuant to the ISO New England Information Policy.

Interconnection Customer has the option to request either that the Interconnection Feasibility Study be completed as a separate and distinct study, or as part of the Interconnection System Impact Study. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 6 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 6 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 6 and Section 7.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Elective Transmission Upgrade Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Elective Transmission Upgrade Interconnection Procedures, in accordance with the Tariff, to: (i) interconnect a new Elective Transmission Upgrade to the Administered Transmission System; (ii) make a Material Modification to an Elective Transmission upgrade with an outstanding Interconnection Request; (iii) increase the capability of an existing Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility that is interconnected to the Administered Transmission System; ~~or (iii~~(iv) make a Material Modification to the design or operating characteristics of an existing Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility that is interconnected with the Administered Transmission System~~.~~; or (v) change from NI Interconnection Service to CNI Interconnection Service for an Elective Transmission Upgrade that is eligible to request such services. Interconnection Request shall not include a request to interconnect to a transmission facility that is not part of the Administered Transmission System.

Interconnection Service shall mean the right to interconnect the Interconnection Customer's Elective Transmission Upgrade to the Administered Transmission System at the Point of Interconnection pursuant to the terms of the Elective Transmission Upgrade Interconnection Agreement and, if applicable, the Tariff. For an External Elective Transmission Upgrade that is a controllable Merchant Transmission Facility or Other Transmission Facility, Interconnection Service shall include Capacity Network Import Interconnection Service or Network Import Interconnection Service.

Long Lead Time Facility ("Long Lead Facility") shall mean a Generating Facility or an Elective Transmission Upgrade with an Interconnection Request for Capacity Network Resource Interconnection Service or Capacity Network Import Interconnection Service, respectively, that has, as applicable, elected or requested long lead time treatment and met the eligibility criteria and requirements specified in Schedule 22 or Schedule 25 of Section II of the Tariff, respectively,

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Elective Transmission Upgrade Interconnection Agreement on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnifying Party.

Major Permits shall be as defined in Section III.13.1.1.2.2.2(a) of the Tariff.

Material Modification shall mean: (i) except as expressly provided in Section 4.4.1, those modifications to the Interconnection Request, including any of the technical data provided by the Interconnection Customer in Attachment A to the Interconnection Request or to the interconnection configuration, requested by the Interconnection Customer, that either require significant additional study of the same Interconnection Request and could substantially change the interconnection design, or have a material impact (*i.e.*, an evaluation of the proposed modification cannot be completed in less than ten (10) Business Days) on the cost or timing of any Interconnection Studies or upgrades associated with an Interconnection Request with a later queue priority date; (ii) a change to the design or operating characteristics of an existing Pool Transmission Facility, Merchant Transmission Facility, or Other Transmission Facility that is interconnected with the Administered Transmission System that may have a significant adverse effect on the reliability or operating characteristics of the New England Transmission System; (iii) a delay to the Commercial Operation Date, In-Service Date, or Trial Operation Date of greater than three (3) years where the reason for delay is unrelated to construction schedules or permitting which delay is beyond the Interconnection Customer's control; (iv) except as provided in Section 3.2.3.4, a withdrawal of a request for Long Lead Facility treatment; or (v) except as provided in Section 3.2.3.6, an election to participate in an earlier Forward Capacity Auction than originally anticipated.

Metering Equipment shall mean all metering equipment installed or to be installed pursuant to the Elective Transmission Upgrade Interconnection Agreement, including but not limited to instrument

Scoping Meeting shall mean the meeting between representatives of the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (a) that the Interconnection Customer is the owner in fee simple of the real property or holds an easement for the Elective Transmission Upgrade's terminal locations at the Point of Interconnection within the New England Control Area; (b) that the Interconnection Customer holds a valid written leasehold or other contractual interest in the real property for the Elective Transmission Upgrade's terminal locations at the Point of Interconnection within the New England Control Area; (c) that the Interconnection Customer holds a valid written option to purchase or a leasehold interest in the real property for the Elective Transmission Upgrade's terminal locations at the Point of Interconnection within the New England Control Area; (d) that the Interconnection Customer holds a duly executed written contract to purchase, acquire an easement, a license or a leasehold interest in the real property for the Elective Transmission Upgrade's terminal locations at the Point of Interconnection within the New England Control Area; or (e) that the Interconnection Customer has filed applications for required permits to site on federal or state property where the Elective Transmission Upgrade's terminal locations will be located at the Point of Interconnection within the New England Control Area.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The System Operator, Interconnection Customer, Interconnecting Transmission Owner, and any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Elective Transmission Upgrade Interconnection Agreement.

Study Case shall have the meaning specified in Sections 6.2 and 7.3 of this ETU IP.

9.3 Interconnecting Transmission Owner and System Operator Obligations. Interconnecting Transmission Owner and System Operator shall cause the Interconnecting Transmission Owner's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this ETU IA and ISO New England Operating Documents, Reliability Standards, or successor documents. Interconnecting Transmission Owner or System Operator may provide operating instructions to Interconnection Customer consistent with this ETU IA, ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and Interconnecting Transmission Owner's and System Operator's operating protocols and procedures as they may change from time to time. Interconnecting Transmission Owner and System Operator will consider changes to their operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Elective Transmission Upgrade and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this ETU IA and ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.5 Start-Up and Trial Operation. The Interconnection Customer is responsible for the proper start-up and Trial Operation of the Elective Transmission Upgrade as part of the New England Transmission System in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.6 Reactive Power.

9.6.1 Power Factor Design Criteria. Interconnection Customer shall design the Elective Transmission Upgrade and Interconnection Facilities that are capable of voltage control to maintain a composite power delivery at continuous rated power output at the Point of Interconnection ~~at a~~with dynamic reactive capability over the power factor ~~within the~~ range of 0.95 leading to 0.95 lagging or any reactive power or power factor requirement specified in the Interconnection System Impact Study for the Elective Transmission Upgrade, unless the System Operator or Interconnecting Transmission Owner has established different requirements that apply to all similar-situated facilities in the

APPENDIX C TO ETU IA

Interconnection Details

1. Description of Interconnection:

This Interconnection Agreement is for an **(***insert either Internal ETU or External ETU description from Article 1 of Appendix I)*

The ETU consists of **(***insert description from Article 2 of Appendix I)*:

The External Elective Transmission Upgrade that is controllable Merchant Transmission Facility or Other Transmission Facility shall receive **(***enter N/A for other ETUs)*:

Network Import Interconnection Service solely for the NI Capability of [*insert amount*] MWs.

Capacity Network Import Interconnection Service for: (i) the NI Capability of [*insert amount*] MWs; and (ii) the CNI Capability of [*insert amount*] MWs. ~~The CNI Capability shall be the aggregate highest megawatt amount of Capacity Supply Obligation obtained by the Import Capacity Resource(s) associated with the External Elective Transmission Upgrade in accordance with Section III.13 of the Tariff.~~

2. Detailed Description of the Elective Transmission Upgrade:

[*Insert any other description relating to the Elective Transmission Upgrade, including updates to all the technical data included on Attachment A to Appendix 1*.]

3. Other Description of Interconnection Plan and Facilities associated with the Elective Transmission Upgrade:

APPENDIX F TO ETU IA

Addresses for Delivery of Notices and Billings Notices:

System Operator:

Transmission Strategy & Services
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

With copy to:
Billing Department
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Interconnecting Transmission Owner:
[To be supplied.]

~~Interconnection Customer:~~
~~[*To be supplied.*]~~

~~**Billings and Payments:**~~

~~System Operator:~~
~~Transmission Strategy & Services~~
~~ISO New England Inc.~~
~~One Sullivan Road~~
~~Holyoke, MA 01040-2841~~

~~With copy to:~~
~~Billing Department~~
~~ISO New England Inc.~~
~~One Sullivan Road~~
~~Holyoke, MA 01040-2841~~

~~Interconnecting Transmission Owner:~~
~~[*To be supplied.*]~~

Interconnection Customer:

[*To be supplied.*]

~~**Alternative Forms of Delivery of Notices (telephone, facsimile or email)**~~:
Billings and Payments:

System Operator:

~~Facsimile: (413) 540-4203~~
~~E-mail: geninterconn@iso-ne.com~~
Transmission Strategy & Services

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040-2841

With copy to:

~~Facsimile: (413) 535-4024~~
~~E-mail: billingdept@iso-ne.com~~
Billing Department

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040-2841

Interconnecting Transmission Owner:

[*To be supplied.*]

Interconnection Customer:

[*To be supplied.*]

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

System Operator:

Facsimile: (413) 540-4203

E-mail: geninterconn@iso-ne.com

With copy to:

Facsimile: (413) 535-4024

E-mail: billingdept@iso-ne.com

Interconnecting Transmission Owner:

[*To be supplied.*]

Interconnection Customer:

[*To be supplied.*]

DUNS Numbers:

Interconnection Customer: [To be supplied]

Interconnecting Transmission Owner: [To be supplied]

ISO new england

memo

To: NEPOOL Participants Committee

From: Erin Wasik-Gutierrez, Secretary
NEPOOL Transmission Committee

Date: January 29, 2016

Subject: **NOTICE OF ACTIONS OF THE TRANSMISSION COMMITTEE** (Revised)

This memo is notification to the Participants Committee of the following actions taken by the Transmission Committee at its meeting on January 26, 2016.

Agenda Item No. 1(A): Meeting Minutes

It was moved and seconded to approve, the November 12 and December 17, 2016 draft Transmission Committee meeting minutes.

Based on a show of hands, the motion to approve the minutes passed unanimously.

Agenda Item No. 2: Interconnection Process Improvements

The following motion was moved and seconded by the Transmission Committee:

Resolved, that the Transmission Committee recommends Participants Committee support for ISO New England Inc. revisions to Schedules 22, 23 and 25 of Section II of the ISO New England Transmission, Markets and Services Tariff, to support the Interconnection Process Improvements, as reflected in the materials distributed to the Transmission Committee for its January 26, 2016 meeting, together with any changes agreed to at the meeting, and such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

(**Vote 1 – Passed** *(Boreas Renewables on behalf of RENEW Northeast)* Before the main motion could be voted, it was moved and seconded by the Transmission Committee to amend the main motion as reflected in the redlines contained in the memo updated January 25, 2016 from Boreas Renewables on behalf of RENEW Northeast.

The motion to amend the main motion was then voted. Based on a show of hands, the motion passed with one (1) opposed from the Transmission sector and one (1) abstention from the Publicly Owned sector.

(Vote 2 – Passed (amended main motion) The amended main motion was moved and seconded by the Transmission Committee.

The amended main motion was then voted. Based on a show of hands, the motion passed with one (1) abstention from the Alternative Resource sector.

memo

Agenda Item No. 3: Notice of Proposed Rulemaking on Reactive Requirements for Non-synchronous Generation

The following motion was moved and seconded by the Transmission Committee:

Resolved, that the Transmission Committee recommends ~~Transmission~~Participants Committee support for the NEPOOL comments in response to the FERC's reactive power rulemaking proposal in Docket No. RM16-1-000, as distributed to the Transmission Committee for its January 26, 2016 meeting, together with any changes agreed to at the meeting.

The motion recommending ~~for Transmission~~Participants Committee support was then voted. Based on a show of hands, the motion passed unanimously.

cc: Transmission Committee

ISO New England Inc.
One Sullivan Road, Holyoke, MA 01040-2841
www.iso-ne.com **T** 413 540 4518 **F** 413 535 4343

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: January 29, 2016

RE: Reactive Power NOPR Comments

At the February 5, 2016, meeting of the Participants Committee you will be asked to vote on NEPOOL Supplemental Comments to be filed in the FERC rulemaking proceeding on reactive power requirements in Docket No RM16-1-000 (the "Reactive Power NOPR"). In the Reactive Power NOPR, the FERC proposes to eliminate the reactive power requirement exemptions for wind generators in both the Large Generator Interconnection Agreement ("LGIA") and the Small Generator Interconnection Agreement ("SGIA"). At its January 26, 2016 meeting the Transmission Committee unanimously recommended Participants Committee support for the Supplemental Comments, which are included with this memo for the February 5 Participants Committee meeting.[1]

By way of brief background, in the Reactive Power NOPR the Commission proposes to revise the LGIA and the SGIA to require all newly interconnecting non-synchronous generators, and all existing non-synchronous generators proposing upgrades to their generation facilities that require new interconnection requests, to design their "generating facilities to maintain reactive power within a power factor range of 0.95 leading to 0.95 lagging, or the standard range established by the transmission provider and approved by the Commission, to be measured at the Point of Interconnection." The Reactive Power NOPR further specifies that the reactive power requirement would be for dynamic reactive power, and that it would apply to non-synchronous generators only when their output is above 10% of their nameplate capacity.

Explaining its proposed change, the FERC states in the Reactive Power NOPR that since providing the reactive power exemptions to wind generators, technology advances and declining equipment costs have made it possible for wind generators to provide reactive power without undue extra costs. Additionally, the FERC noted that increasing penetration of wind power on the grid increases the potential for a deficiency of reactive power, and could unfairly put the burden of maintaining reactive power on synchronous generators, without a change to the current rules. For these reasons, the FERC concludes that the continued exemption from the reactive power requirement in the *pro forma* LGIA and the *pro forma* SGIA for newly interconnecting wind generators appears to be unjust, unreasonable, and unduly discriminatory or preferential.

Comments in the Reactive Power NOPR proceeding were due on January 27, 2016. NEPOOL Counsel filed Initial Comments by that date that reflected the Transmission Committee

---

[1] Other documents included with your materials for this agenda item are: NEPOOL's Initial Comments filed in this proceeding on January 27, 2016, a NEPOOL counsel memo summarizing the Reactive Power NOPR and the Reactive Power NOPR.

input and vote and noted the need for a Participants Committee vote on February 5. The Supplemental Comments, subject to Participants Committee input and vote, are to be filed shortly following that vote. Both sets of comments reference the generator interconnection revisions that are on the same schedule for NEPOOL votes, and which contain a reactive power requirement for wind generators that is similar to but not the same in all details as what the FERC is proposing.

The substance of the comments is that NEPOOL supports the general direction of the Reactive Power NOPR proposal, but NEPOOL and the region want the ISO to have the flexibility, with NEPOOL support, to appropriately deviate in specific details from any standardized *pro forma* rule. With respect to any compliance requirement that comes out of the Reactive Power NOPR, and in considering New England's intended filing of the Generator Interconnection Revisions and their reactive power requirement, NEPOOL urges the Commission to continue to allow for regional flexibility under its independent entity variation, so that New England can customize its interconnection procedures and agreements to fit regional needs.

The following resolution could be used for Participants Committee consideration of this matter:

> RESOLVED, that the Participants Committee supports the NEPOOL Supplemental Comments in the Reactive Power NOPR, as recommended by the Transmission Committee and as reflected in the materials distributed to the Participants Committee for its February 5, 2016 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Vice-Chair of the Transmission Committee.

DRAFT 1/27/16

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

ISO New England Inc.	**)**	**Docket No. RM16-1-000**

**SUPPLEMENTAL COMMENTS OF
NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE**

(February 5, 2016)

The New England Power Pool ("NEPOOL") Participants Committee[1] hereby provides its supplemental comments ("Supplemental Comments") on the Federal Energy Regulatory Commission's (the "Commission") "Proposal to Revise Standard Generator Interconnection Agreements" to eliminate the exemptions for wind generators from the requirement to provide reactive power ("Reactive Power NOPR").[2]

On January 27, 2016, NEPOOL filed a set of initial comments in this proceeding ("Initial Comments")[3], and indicated that NEPOOL would supplement its comments shortly after it completed the NEPOOL stakeholder process on this topic with its February 5 Participants Committee meeting. As described in the Initial Comments, the Participants Committee February 5 meeting agenda had votes scheduled on these Supplemental Comments and on a set of

[1] NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include approximately 430 members. The Participants include all of the electric utilities rendering or receiving services under the ISO Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, end users, developers, and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission in *ISO New England Inc. et al.*, 109 FERC ¶ 61,147 (2004), the Participants act through the NEPOOL Participants Committee. The NEPOOL Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. NEPOOL is the principal stakeholder organization for the New England Regional Transmission Organization ("RTO").

[2] "Reactive Power Requirements for Non-Synchronous Generation", 153 FERC ¶ 61,175, Docket No. RM16-1-000 (2015).

[3] NEPOOL hereby incorporates by reference the background and comments contained in its Initial Comments.

generator interconnection reforms that included a reactive power requirement for non-synchronous generators. NEPOOL and ISO New England Inc. ("ISO-NE" or the "ISO") have been developing those generator interconnection reforms independent of this proceeding, but the reactive power piece of them directly relates to the subject of the Reactive Power NOPR. This set of Supplemental Comments updates the Commission on the outcome of the February 5 Participants Committee votes and affirms NEPOOL's Initial Comments.

I. BACKGROUND

As described in NEPOOL's Initial Comments during the latter half of 2015 and into 2016 NEPOOL has been working with the ISO and other New England parties to develop revisions to the regional interconnection rules to improve the interconnection process and specifically to address some of the particular issues related to non-synchronous wind generators coming onto the system (the "Generator Interconnection Revisions"). The general goals of the project are: (i) to reduce the time to interconnect new generators; (ii) to address some of the operational issues related to inverter-based generators; and (iii) to meet NERC modeling and performance requirements.

With regard to the second of these goals, addressing operational issues in the interconnection process related to non-synchronous generators, ISO-NE has identified the lack of a reactive power requirement for non-synchronous generators as a factor that contributes to delays, added expense and other problems in the interconnection process for such generators. The ISO has proposed, and NEPOOL has just completed voting on, revisions to the interconnection rules that would implement a reactive power requirement for all non-synchronous generators, such that they would no longer be exempt from the requirement that applies to all other generators.

DRAFT 1/27/16

As noted in its Initial Comments, on January 26, the Transmission Committee voted on the Generator Interconnection Revisions, including the reactive power requirement for non-synchronous generators, and unanimously recommended Participants Committee support for them. At that same meeting, the Transmission Committee voted unanimously to support NEPOOL's Initial Comments and recommend Participants Committee support for this set of Supplemental Comments in this proceeding.

At its February 5, 2016, meeting the Participants Committee voted on and supported both the Generator Interconnection Revisions and these Supplemental Comments.[4]

II. SUPPLEMENTAL COMMENTS

NEPOOL supports the general direction of the Commission's Reactive Power NOPR to require non-synchronous interconnecting generators to have a dynamic reactive power capability within the power factor range of 0.95 leading to 0.95 lagging. That proposal is consistent with the direction in which NEPOOL and ISO-NE are already heading with the Generator Interconnection Revisions, though New England will have some specific differences in the details of its reactive power requirement.

NEPOOL wants ISO-NE to have the flexibility, with NEPOOL support, to appropriately deviate in specific details from any standardized *pro forma* rule. With respect to any compliance requirement that comes out of the Reactive Power NOPR, and in considering New England's intended filing of the Generator Interconnection Revisions and their reactive power requirement, NEPOOL urges the Commission to continue to allow for regional flexibility under its

[4] [Provide specifics of votes.]

DRAFT 1/27/16

independent entity variation, so that New England can customize its interconnection procedures and agreements to fit regional needs.[5]

III. CONCLUSION

NEPOOL and ISO-NE are well on the path to define and implement improvements that are fully consistent with the direction of the Reactive Power NOPR. NEPOOL requests that the Commission consider these Supplemental Comments in its Reactive Power NOPR proceeding.

Respectfully submitted,
NEPOOL Participants Committee

By: /s/ Eric K. Runge

Eric K. Runge
Day Pitney LLP
One International Place
Boston, MA 02110
Tel: (617) 345-4735
E-mail: ekrunge@daypitney.com

Dated: February 5, 2016

[5] NEPOOL and ISO-NE intend to undertake a consideration of potential revisions to reactive power compensation rules later in 2016, and NEPOOL, therefore, reserves any comments on compensation until after that stakeholder process has occurred.

DRAFT 1/27/16

CERTIFICATE OF SERVICE

I hereby certify that I caused a copy of the foregoing document to be served electronically upon each person designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission.

Dated at Washington D.C. this 5th day of February 2016.

/s/ James B. Blackburn IV
Day Pitney LLP
1100 New York Ave., NW Suite 300
Washington D.C. 200005
Tel: (202) 218-3905
Fax: (202) 354-4848
E-mail: jblackburn@daypitney.com

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. RM16-1-000**

INITIAL COMMENTS OF
NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE

(January 27, 2016)

The New England Power Pool ("NEPOOL") Participants Committee[1] hereby provides its initial comments ("Initial Comments") on the Federal Energy Regulatory Commission's (the "Commission") "Proposal to Revise Standard Generator Interconnection Agreements" to eliminate the exemptions for wind generators from the requirement to provide reactive power ("Reactive Power NOPR").[2]

In the Reactive Power NOPR the Commission proposes to revise the Large Generator Interconnection Agreement and the Small Generator Interconnection Agreement to require all newly interconnecting non-synchronous generators, and all existing non-synchronous generators proposing upgrades to their generation facilities that require new interconnection requests, to design their "generating facilities to maintain reactive power within a power factor range of 0.95 leading to 0.95 lagging, or the standard range established by the transmission provider and

[1] NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include approximately 430 members. The Participants include all of the electric utilities rendering or receiving services under the ISO Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, end users, developers, and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission in *ISO New England Inc. et al.*, 109 FERC ¶ 61,147 (2004), the Participants act through the NEPOOL Participants Committee. The NEPOOL Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. NEPOOL is the principal stakeholder organization for the New England Regional Transmission Organization ("RTO").

[2] Reactive Power Requirements for Non-Synchronous Generation, 153 FERC ¶ 61,175, Docket No. RM16-1-000 (2015).

approved by the Commission, to be measured at the Point of Interconnection."[3] The Reactive Power NOPR further specifies that the reactive power requirement would be for dynamic reactive power, and that it would apply to non-synchronous generators only when their output is above 10% of their nameplate capacity.[4]

This set of NEPOOL Initial Comments, including its background section, provides a status report both on NEPOOL's consideration of the Reactive Power NOPR and on NEPOOL's own consideration with ISO New England Inc. ("ISO-NE" or the "ISO") of the reactive power requirement for non-synchronous (i.e., primarily wind) generators, that has been ongoing in New England for several months, independent of the Commission's Reactive Power NOPR.

Due to the timing of its next Participants Committee meeting on February 5, 2016, NEPOOL cannot provide definitive substantive comments now, but will supplement these Initial Comments with additional comments on or shortly after February 5, 2016 ("Supplemental Comments").

I. BACKGROUND

NEPOOL, along with ISO-NE[5], the Participating Transmission Owners ("PTOs")[6] and the representatives of the New England states have been at the forefront of trying to ensure that generator interconnection rules work for New England, while being compliant with the Commission's *pro forma* generator interconnection rules.

---

[3] Reactive Power NOPR at P 13. The proposed requirement would not apply to generators under existing interconnection agreements absent a change that triggers a new interconnection request.

[4] *Id*. at PP 14-15.

[5] ISO-NE has been in charge of managing the generator interconnection queue since the ISO's inception in 1997, and has had Section 205 filing rights over the generator interconnection portions of the OATT in New England since it became an RTO in 2005.

[6] The PTOs are the entities that own transmission in New England and are parties to the Transmission Operating Agreement with ISO-NE as part of the New England RTO arrangements.

In compliance with Order No. 2003[7], NEPOOL, through the NEPOOL Open Access Transmission Tariff ("OATT"), adopted the standardized large generator interconnection procedures ("LGIP").[8] In adopting the LGIP, NEPOOL and ISO-NE proposed and the Commission accepted a number of regional variations from the *pro forma* LGIP, under the "independent entity variations" standard articulated in Order No. 2003[9], to accommodate the particularities of the New England transmission and wholesale markets system. Similarly, in compliance with Order No. 2006, the ISO-NE OATT adopted the standardized small generator interconnection procedures ("SGIP") with appropriate regional variations.[10] The LGIP and SGIP are contained in Schedule 22 and 23 of the ISO-NE OATT.

---

[7] See *Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003*, 68 Fed. Reg. 49,845 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, order on reh'g, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); *see also Notice Clarifying Compliance Procedures*, 106 FERC ¶ 61,009 (2004) ("Order No. 2003"). *See also New England Power Pool (Standardizing Generator Interconnection Agreements and Procedures): Order No. 2003 Compliance Filing* (Jan. 20, 2004), Docket No. ER04-433-000 ("Order No. 2003 Compliance Filing"). A contemporaneous compliance filing was made by the NEPOOL transmission owners concerning the local facilities subject to their control. The ISO, PTOs and NEPOOL also made subsequent compliance filings with Order Nos. 2003-A, -B and -C. See Order No. 2003-A and-B compliance filing in Docket Nos. RT04-2-010, RT04-2-011, RT04-2-012, ER04-116-010, ER04-116-011, ER04-116-012, ER04-157-012, EL01-39-010, ER04-433- 002, ER04-433-004, ER04-432-002, ER04-432-004, and ER04-459-000 (January 28, 2005), accepted in *ISO New England Inc., et al*., 110 FERC ¶ 61,335 (2005). See also Order No. 2003-C compliance filing in Docket No. ER05-1342-000 (August 15, 2005), accepted in a letter order issued November 22, 2005.

[8] When ISO-NE became the RTO for New England in 2005, the NEPOOL OATT became the ISO-NE OATT.

[9] *See* Order No. 2003 at P 827: "With respect to an RTO or ISO, at the time its compliance filing is made, as discussed above, we will allow it to seek "independent entity variations" from the Final Rule pricing and non-pricing provisions. This is a balanced approach that recognizes that an RTO or ISO has different operating characteristics depending on its size and location and is less likely to act in an unduly discriminatory manner than a Transmission Provider that is a market participant. The RTO or ISO shall therefore have greater flexibility to customize its interconnection procedures and agreements to fit regional needs."

[10] *Order No. 2006*, FERC Stats. & Regs. ¶ 31,180, *order on reh'g, Order No. 2006-A*, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification, Order No. 2006-B*, FERC Stats. & Regs. ¶ 31,221 (2006), *appeal pending sub nom. Consolidated Edison Co. of New York, Inc., et al. v. FERC*, Docket No.

In 2008, NEPOOL, ISO-NE, the New England states and other interested parties, on their own initiative, undertook generator interconnection queue reforms to integrate the New England Forward Capacity Market ("FCM") processes and requirements with the generator interconnection rules, and to provide other general improvements to those rules. In 2014 and early 2015, NEPOOL again worked with the ISO to develop and file revisions to the regional interconnection rules to provide clear and certain rules for the interconnection of Elective Transmission Upgrades ("ETU") and to integrate those ETU interconnections with the FCM processes and requirements.[11]

Similarly, during the latter half of 2015 and into 2016, NEPOOL has been working with the ISO and other New England parties to develop revisions to the regional interconnection rules to improve the interconnection process and specifically to address some of the particular issues related to non-synchronous wind generators coming onto the system (the "Generator Interconnection Revisions"). The general goals of the project are: (i) to reduce the time to interconnect new generators; (ii) to address some of the operational issues related to inverter-based generators; and (iii) to meet NERC modeling and performance requirements.

06-1018, et al; *Interconnection for Wind Energy, Order No. 661*, FERC Stats. & Regs. ¶ 31,186, *order on reh'g, Order No. 661-A*, FERC Stats. & Regs. ¶ 31,198 (2005). The ISO, PTOs and NEPOOL initially filed Schedule 23 of the ISO OATT in response to the Commission's Order No. 2006 and Order No. 2006-A on November 10, 2005 and February 15, 2006, in Docket No. ER06-191-000. On April 14, 2006, the Commission issued an Order accepting in part and rejecting in part certain proposed variations to the Commission's pro forma SGIP and SGIA. *See ISO New England Inc*., 115 FERC ¶ 61,050 (2006). On May 15, 2006, as amended on June 1, 2006, and supplemented on October 23, 2006, those filing parties submitted a subsequent filing in compliance with the Commission's April 14 Order, in Docket No. ER06-191, which was accepted by the Commission in a letter order issued on April 13, 2007. These parties (and Maine Electric Power Co.) made an Order No. 2006-B compliance filing in ER07-87, which was accepted in part and rejected in part in *ISO New England Inc*., 119 FERC ¶ 61,293 (2007). A subsequent compliance filing in Docket No. ER07-87 was made on July 23, 2007, which was accepted by letter order issued December 3, 2007.

[11] The ETU rules were filed on February 13, 2015, in Docket No. ER15-1050 and were accepted by order dated April 14, 2015. *ISO New England Inc.*, 151 FERC ¶ 61,024 (2015). The ETU interconnection rules are contained in Schedule 25 of the ISO-NE OATT.

With regard to the second of these goals, addressing operational issues in the interconnection process related to non-synchronous generators, ISO-NE has identified the lack of a reactive power requirement for non-synchronous generators as a factor that contributes to delays, added expense and other problems in the interconnection process for such generators. The ISO has proposed, and NEPOOL is considering and in the process of voting on, revisions to the interconnection rules that would implement a reactive power requirement for all non-synchronous generators, such that they would no longer be exempt from the requirement that applies to all other generators.

As noted above, NEPOOL and ISO-NE have been discussing the Generator Interconnection Revisions since around mid-2015. Under the Participants Agreement that governs the NEPOOL/ISO-NE stakeholder process for revisions to the ISO-NE OATT, the revisions are first considered and voted on by the NEPOOL Transmission Committee and then go to the Participants Committee for a vote. On January 26, 2016, the Transmission Committee voted on the Generator Interconnection Revisions, including the reactive power requirement for non-synchronous generators, and unanimously recommended Participants Committee support for them. At that same meeting the Transmission Committee voted unanimously to support these Initial Comments and recommend Participants Committee support for a set of Supplemental Comments in this proceeding. The Participants Committee will vote on both the Generator Interconnection Revisions and the Supplemental Comments at its upcoming February 5, 2016, meeting. NEPOOL will file its Supplemental Comments shortly thereafter.

II. INITIAL COMMENTS

Based on NEPOOL discussions to date and the January 26, 2016, Transmission Committee votes, and subject to the outcome of the upcoming Participants Committee votes, NEPOOL Participants appear to support the general direction of the Reactive Power NOPR to require non-synchronous interconnecting generators to have a dynamic reactive power capability within the power factor range of 0.95 leading to 0.95 lagging. The Reactive Power NOPR is consistent with the direction in which NEPOOL and ISO-NE are already heading with the Generator Interconnection Revisions, though New England will have some specific differences in the details of its reactive power requirement.

NEPOOL wants ISO-NE to have the flexibility, with NEPOOL support, to appropriately deviate in specific details from any standardized *pro forma* rule. With respect to any compliance requirement that comes out of the Reactive Power NOPR, and in considering New England's intended filing of the Generator Interconnection Revisions and their reactive power requirement, NEPOOL urges the Commission to continue to allow for regional flexibility under its independent entity variation, so that New England can customize its interconnection procedures and agreements to fit regional needs.[12]

[12] NEPOOL and ISO-NE intend to undertake a consideration of potential revisions to reactive power compensation rules later in 2016, and NEPOOL, therefore, reserves any comments on compensation until after that stakeholder process has occurred.

III. CONCLUSION

NEPOOL and ISO-NE are well on the path to define and implement improvements that are fully consistent with the direction of the Reactive Power NOPR. The NEPOOL Participants Committee requests that the Commission consider these Initial Comments in its Reactive Power NOPR proceeding. NEPOOL will supplement these comments shortly after its February 5, 2016, Participants Committee meeting.

Respectfully submitted,
NEPOOL Participants Committee

By: *\/s/ Eric K. Runge*

Eric K. Runge
Day Pitney LLP
One International Place
Boston, MA 02110
Tel: (617) 345-4735
E-mail: ekrunge@daypitney.com

Dated: January 27, 2016

CERTIFICATE OF SERVICE

I hereby certify that I caused a copy of the foregoing document to be served electronically upon each person designated on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission.

Dated at Washington D.C. this 27th day of January 2016.

/s/ James B. Blackburn IV
James B. Blackburn IV
Day Pitney LLP
1100 New York Ave., NW
Washington D.C. 200005
Tel: (202) 218-3905
Fax: (202) 354-4848
E-mail: jblackburn@daypitney.com

M E M O R A N D U M

TO: NEPOOL Transmission Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: December 10, 2015

RE: FERC's Proposed Reactive Power Requirement for Wind Generators

---

On November 19, 2015, the Federal Energy Regulatory Commission (the "FERC") issued its "Proposal to Revise Standard Generator Interconnection Agreements" to eliminate the exemptions for wind generators from the requirement to provide reactive power ("Reactive Power Proposal") in Docket No. RM16-1-000.[1] This memo briefly describes the Reactive Power Proposal and the process associated with it. If you have any questions about this memo or its subject, please contact Eric Runge, 617-345-4735, ekrunge@daypitney.com.
****

The Proposal would remove an exemption that has existed for wind generators since the inception of the standardized generator interconnection procedures and agreements. In 2003 with Order No. 2003 the Commission adopted standardized Large Generator Interconnection Procedures ("LGIP") and a Large Generator Interconnection Agreement ("LGIA") for the interconnection of generators larger than 20 MW.[2] Section 9.6.1 of the *pro forma* LGIA contains a requirement that interconnecting generators have a dynamic reactive power capability within the range of 0.95 leading to 0.95 lagging. Order No. 2003-A provided an exemption to the reactive power requirement for wind generators, absent a study finding that the provision of reactive power from a particular generator is necessary to ensure safety or reliability. The exemption was based on FERC's recognition then that non-synchronous wind generators might not be similarly situated with large synchronous generators in their ability to provide reactive power without the installation of costly extra equipment.[3] In 2005 in Order No. 661 the FERC established special interconnection requirements for wind generators, again providing the exemption from the reactive power requirement on the grounds that non-synchronous generators

---

[1] *See, Reactive Power Requirements for Non-Synchronous Generation*, 153 FERC ¶ 61,175, (2015). The Reactive Power Proposal can be accessed through the following link and has been distributed to the Transmission Committee: http://www.ferc.gov/whats-new/comm-meet/2015/111915/E-3.pdf.

[2] *See, Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 542 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), cert. denied, 552 U.S. 1230 (2008).

[3] See Reactive Power Proposal at P 6.

could not meet the requirement without installing costly equipment.[4] Also in 2005, the FERC issued Order No. 2006, providing standardized Small Generator Interconnection Procedures ("SGIP") and a Small Generator Interconnection Agreement ("SGIA") for generators 20 MW or smaller.[5] Section 1.8.1 of the *pro forma* SGIA provides both the reactive power requirement for small generators and a complete exemption to wind generators from that requirement.

In the Reactive Power Proposal the FERC states that since providing the reactive power exemptions to wind generators, technology advances and declining equipment costs have made it possible for wind generators to provide reactive power without undue extra costs.[6] Additionally, increasing penetration of wind power on the grid increases the potential for a deficiency of reactive power, and could unfairly put the burden of maintaining reactive power on synchronous generators, without a change to the current rules.[7] Therefore, the FERC states that the continued exemption from the reactive power requirement in the *pro forma* LGIA and the *pro forma* SGIA for newly interconnecting wind generators appears to be unjust, unreasonable, and unduly discriminatory or preferential,[8] and is proposing to eliminate the reactive power exemptions in both the LGIA and SGIA for wind generators.

The Reactive Power Proposal would require all newly interconnecting non-synchronous generators and all existing non-synchronous generators proposing upgrades to their generation facilities that require new interconnection requests to design their "generating facilities to maintain reactive power within a power factor range of 0.95 leading to 0.95 lagging, or the standard range established by the transmission provider and approved by the Commission, to be measured at the Point of Interconnection."[9] The Reactive Power Proposal further specifies that the reactive power requirement would be for dynamic reactive power, and that it would apply to non-synchronous generators only when their output is above 10% of their nameplate capacity.[10] The FERC is proposing a compliance deadline of 90 days from the date of a final order revising the LGIA and SGIA.[11]

---

[4] *See, Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186, Appendix B (Appendix G – Interconnection Requirements for a Wind Generating Plant), *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005).

[5] *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, Attachment F (Small Generator Interconnection Agreement), *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

[6] Reactive Power Proposal at P 10.

[7] *Id*. at P 11.

[8] *Id*. at P 10.

[9] *Id.* at P 13.

[10] *See, Id*. at PP 14-15.

[11] *Id.* at P 19.

The FERC is seeking comments on its Reactive Power Proposal by January 26, 2016. NEPOOL counsel plans to discuss with the Transmission Committee the potential for any comments from NEPOOL and/or ISO-NE, and how the Reactive Power Proposal relates to the current reforms to the generator interconnection process being considered by NEPOOL.

153 FERC ¶ 61,175
DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM16-1-000]

Reactive Power Requirements for Non-Synchronous Generation

(Issued November 19, 2015)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Proposal to Revise Standard Generator Interconnection Agreements.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to eliminate the exemptions for wind generators from the requirement to provide reactive power. As a result, all newly interconnecting generators, including both synchronous and non-synchronous generators, would be required to provide reactive power. To implement this requirement, the Commission proposes to revise the *pro forma* Large Generator Interconnection Agreement (LGIA), Appendix G to the *pro forma* LGIA, and the *pro forma* Small Generator Interconnection Agreement (SGIA) in accordance with the Commission's regulations, which require every public utility with a non-discriminatory open access transmission tariff on file to also have on file the *pro forma* LGIA and *pro forma* SGIA "required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements." In this Proposal to Revise Standard Generator Interconnection Agreements (Proposal), the Commission proposes to modify both agreements to eliminate the exemptions for wind generators from the requirement to provide reactive power. As a result, all newly interconnecting generators

(i.e., new generators seeking to interconnect to the transmission system and all existing non-synchronous generators making upgrades to their generation facilities that require new interconnection requests), both synchronous and non-synchronous, would be required to provide reactive power as a condition of interconnection as of the effective date of the final revision.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER]**.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through http://www.ferc.gov. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on this process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

Brian Bak (Technical Information)
Office of Energy Policy and Innovation
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-6574
brian.bak@ferc.gov

Gretchen Kershaw (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8213
gretchen.kershaw@ferc.gov

SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reactive Power Requirements for Non-Synchronous Generation — Docket No. RM16-1-000

PROPOSAL TO REVISE STANDARD GENERATOR INTERCONNECTION AGREEMENTS

(Issued November 19, 2015)

1. In this Proposal to Revise Standard Generator Interconnection Agreements (Proposal), the Federal Energy Regulatory Commission (Commission) is proposing to eliminate the exemptions for wind generators from the requirement to provide reactive power. As a result, all newly interconnecting generators, including both synchronous and non-synchronous, would be required to provide reactive power. Specifically, the Commission proposes to modify the two *pro forma* interconnection agreements, the Large Generator Interconnection Agreement (LGIA) and the Small Generator Interconnection Agreement (SGIA), to eliminate the current exemption for wind generators from the requirement to provide reactive power, thereby requiring all newly interconnecting generators (i.e., new generators seeking to interconnect to the transmission system and all existing non-synchronous generators making upgrades to their generation facilities that require new interconnection requests), both synchronous and non-synchronous, to provide reactive power. This Proposal would create comparable reactive power requirements for non-synchronous and synchronous generators, except that the Proposal requires that non-synchronous generators maintain the required power factor range only when the generator's real power output exceeds 10 percent of its

nameplate capacity. Additionally, all existing non-synchronous generators making upgrades to their generation facilities that require new interconnection requests would be required to provide reactive power.

2. The existing *pro forma* LGIA and *pro forma* SGIA both require, as a condition of interconnection, an interconnecting generator "to design its generating facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor[1] of 0.95 leading to 0.95 lagging, or a different range if adopted by the Transmission Provider"[2] (i.e., the reactive power requirement). This reactive power requirement requires dynamic reactive power[3] from generators. As discussed below, however, wind generators have been exempted from the reactive power

---

[1] The power factor of an alternating current transmission system is the ratio of real power to apparent power. Reliable operation of a transmission system requires system operators to maintain a tight control of voltages (at all points) on the transmission system. The ability to vary the ratio of real power to apparent power (i.e., adjust the power factor) allows system operators to maintain scheduled voltages within allowed for tolerances on the transmission system and maintain the reliability of the transmission system. The Commission established a required power factor range in Order No. 2003 of 0.95 leading to 0.95 lagging. *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 542 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

[2] Section 9.6.1 of the *pro forma* LGIA and section 1.8.1 of the *pro forma* SGIA.

[3] Reactive power sources are generally categorized as static or dynamic based on the speed and continuity at which they can produce or absorb reactive power in response to changes in system conditions. In general, dynamic reactive power devices are characterized by faster acting and continuously variable voltage control capability.

requirement absent a study finding the provision of reactive power necessary, because historically, costs for an interconnection customer to design and build a wind generator that could provide reactive power were high and could have created an obstacle to the development of wind generation.[4] However, due to technological advancements, wind generators can now provide reactive power more cheaply and the cost of providing reactive power no longer presents an obstacle to the development of wind generation.[5] The subsequent decline in the cost to wind generators of providing reactive power may make it unduly discriminatory and preferential to exempt wind generators from the reactive power requirement when other types of generators are not exempt. Further, the growing penetration of wind generators on some systems increases the potential for a deficiency in reactive power.[6] Given this potential, the Commission's current requirement that the transmission provider conduct a study to determine whether each new wind generator needs to provide reactive power may unduly place the burden of supplying reactive power on synchronous generators without a reasonable technological or cost-based basis.

3. Therefore, the Commission proposes to eliminate the existing exemptions for wind generators, and thereby require that all newly interconnecting non-synchronous

---

[4] *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186, at P 51, *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005).

[5] *Payment for Reactive Power*, Commission Staff Report, Docket No. AD14-7, app. 2, at 1-3 (Apr. 22, 2014).

[6] *See PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097, at P 7 (2015).

generators provide dynamic reactive power as a condition of interconnection. This requirement would also apply to all existing non-synchronous generators making upgrades to their generation facilities that require new interconnection requests. The proposals set forth in this Proposal are intended to ensure that all generators, synchronous and non-synchronous, are treated in a not unduly discriminatory or preferential manner, as required by sections 205 and 206 of the Federal Power Act (FPA),[7] and to ensure sufficient reactive power is available on the electric grid as more non-synchronous generators seek to interconnect.

4. The Commission seeks comment on these proposed reforms sixty (60) days after publication of this Proposal in the *Federal Register*.

Background

5. Transmission providers require reactive power to control system voltage for efficient and reliable operation of an alternating current transmission system. At times, transmission providers need generators to either supply or consume reactive power. Starting with Order No. 888,[8] which included provisions regarding reactive power from

[7] 16 U.S.C. §§ 824a, 824b (2012).

[8] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

generators as an ancillary service in Schedule 2 of the *pro forma* Open Access Transmission Tariff (OATT), the Commission issued a series of orders intended to ensure that sufficient reactive power is available to maintain the reliability of the electric grid.

6. Starting with Order No. 2003, the Commission adopted standard procedures and a standard agreement for the interconnection of large generation facilities (the *pro forma* LGIA), which included the reactive power requirement.[9] The Commission recognized in Order No. 2003-A that the *pro forma* LGIA was "designed around the needs of large synchronous generators and that generators relying on newer technologies may find that either a specific requirement is inapplicable or that it calls for a slightly different approach" because such generators "may have unique electrical characteristics."[10] Therefore, the Commission exempted wind generators from the reactive power requirement and added a blank Appendix G to the *pro forma* LGIA as a placeholder for future interconnection requirements for newer technologies.[11]

---

[9] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 1, 542.

[10] Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 407 & n.85.

[11] *Id.* Article 9.6.1 of the *pro forma* LGIA provides: "Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis. The requirements of this paragraph shall not apply to wind generators."

7. In June 2005, the Commission issued Order No. 661,[12] establishing interconnection requirements in Appendix G to the *pro forma* LGIA for large wind generators.[13] Recognizing that, unlike traditional synchronous generators, wind generators had to "install costly equipment" in order to maintain reactive power capability, the Commission in Order No. 661 preserved the exemption for large wind generators from the reactive power requirement unless the transmission provider shows, through a System Impact Study, that reactive power capability is required to ensure safety or reliability.[14] The Commission explained that this qualified exemption from the reactive power requirement for large wind generators would provide certainty to the industry and "remove unnecessary obstacles to the increased growth of wind generation."[15]

8. In May 2005, the Commission issued Order No. 2006,[16] in which it adopted standard procedures and a standard agreement for the interconnection of small generation

---

[12] *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186, Appendix B (Appendix G – Interconnection Requirements for a Wind Generating Plant), *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005).

[13] *Id.* P 1.

[14] *Id.* PP 50-51. Appendix G states: "A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety and reliability."

[15] *Id.* P 50.

[16] *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, Attachment F (Small

(continued…)

facilities (*pro forma* SGIA).[17] In Order No. 2006, the Commission completely exempted small wind generators from the reactive power requirement.[18] The Commission reasoned that, similar to large wind generators, small wind generators would face increased costs to provide reactive power that could create an obstacle to the development of small wind generators. Additionally, the Commission reasoned that small wind generators would "have minimal impact on the Transmission Provider's electric system" and therefore the reliability requirements for large wind generators that were eventually imposed in Order No. 661 were not needed for small wind generators.[19]

9. Since the Commission provided these exemptions from the reactive power requirement for wind generators, the equipment needed for a wind generator to provide reactive power appears to have become more commercially available and less costly, such that the cost of installing equipment that is capable of providing reactive power is

---

Generator Interconnection Agreement), *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

[17] *Id.* P 1.

[18] *Id.* P 387. Section 1.8.1 of the *pro forma* SGIA states: "The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all similarly situated generators in the control area on a comparable basis. The requirements of this paragraph shall not apply to wind generators."

[19] *Id.* P 24.

comparable to the costs of a traditional generator.[20] Recognizing these factors, the Commission recently accepted a proposal by PJM Interconnection, L.L.C. (PJM) to effectively remove the wind generator exemption from the PJM tariff.[21] Specifically, the Commission granted PJM an "independent entity variation" from Order No. 661 in accepting PJM's proposal to require interconnection customers seeking to interconnect non-synchronous generators,[22] including wind generators, to use "enhanced inverters" with the capability to provide reactive power.[23] The Commission observed that, "[a]lthough there are still technical differences between non-synchronous generators [such as wind generators] and traditional generators, with regard to the provision of reactive power, those differences have significantly diminished since the Commission issued Order No. 661."[24] The Commission agreed with PJM "that the technology has changed both in availability and in cost since the Commission rejected [the California

---

[20] *Payment for Reactive Power*, Commission Staff Report, Docket No. AD14-7, app. 1, at 6, app. 2, at 4-5 (Apr. 22, 2014).

[21] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097, at P 28 (2015).

[22] Non-synchronous generators are "connected to the bulk power system through power electronics, but do not produce power at system frequency (60 Hz)." They "do not operate in the same way as traditional generators and respond differently to network disturbances." *Id.* P 1 n.3 (citing Order No. 661, FERC Stats. & Regs. ¶ 31,198 at P 3 n.4). Wind and solar photovoltaic generators are two examples of non-synchronous generators.

[23] *Id.* PP 1, 6.

[24] *Id.* P 28.

Independent System Operator's] proposal in 2010," such that "PJM's proposal will not present a barrier to non-synchronous resources."[25]

Discussion

10. The continued exemption from the reactive power requirement in the *pro forma* LGIA and the *pro forma* SGIA for newly interconnecting wind generators appears to be unjust, unreasonable, and unduly discriminatory or preferential. Older wind turbine generators consumed reactive power; however, they lacked the capability to produce and control reactive power without the use of costly equipment because they did not use inverters like other non-synchronous generators.[26] Technological advances have been made in the inverters used by wind generators.[27] Based on these improvements, requiring newly interconnecting wind generators to provide reactive power does not appear to be the obstacle to the development of wind generation that it was when the Commission issued Order Nos. 2003, 661, and 2006.[28] In particular, the wind turbines being installed

---

[25] *Id.*

[26] Order No. 661, FERC Stats. & Regs. ¶ 31,186 at PP 50-51.

[27] Non-synchronous generators produce electricity that is not synchronized to the electric grid (i.e., direct current (DC) power or alternating current (AC) power at a frequency other than 60 hertz). Inverters convert non-synchronized AC or DC power into synchronized AC power that can be transmitted on the transmission system.

[28] As discussed above, in exempting wind generators from the reactive power requirement, the Commission sought to avoid creating an obstacle to the development of wind generation. For example, in Order No. 661, the Commission was concerned with "remov[ing] unnecessary obstacles to the increased growth of wind generation." *Id.* P 50.

today are generally Type III and Type IV inverter-based turbines,[29] which are capable of producing and controlling dynamic reactive power, which was not the case in 2005 when the Commission exempted wind generators from the reactive power requirement in Order No. 661.[30] The Commission preliminarily concludes that improvements in technology and the corresponding declining costs to newly interconnecting wind generators in providing reactive power make it unduly discriminatory and preferential to exempt such non-synchronous generators from the reactive power requirement when other types of generators are not exempt. Given the reduced costs to newly interconnecting wind generators to provide reactive power, requiring them to operate within the required power factor range would ensure they satisfy the same requirements as other generators and satisfy a basic requirement of interconnection.[31]

11. Further, the Commission is concerned that, as the penetration of wind generation continues to grow, exempting a class of generators from providing reactive power could create reliability issues if those generators represent a substantial amount of total

---

[29] A Type III wind turbine is a non-synchronous wound-rotor generator that has a three phase AC field applied to the rotor from a partially-rated power-electronics converter. A Type IV wind turbine is an AC generator in which the stator windings are connected to the power system through a fully-rated power-electronics converter. Both Type III and Type IV wind turbines have inherent reactive power capabilities.

[30] *Id.* PP 50-51.

[31] *See, e.g., Sw. Power Pool, Inc.*, 119 FERC ¶ 61,199, at P 29 ("Providing reactive power within the [standard power factor range] is an obligation of a generator, and is as much an obligation of a generator as, for example, operating in accordance with Good Utility Practice."), *order on reh'g*, 121 FERC ¶ 61,196 (2007).

generation, or if many of the resources that currently provide reactive power are retired from operation. Local reliability issues, due to the short distances that reactive power can be transmitted, that are not readily apparent given the current generation mix could result if a region were to lose synchronous resources that supply reactive power and the resulting generation mix consisted of a significant quantity of resources that were exempt from providing reactive power. Further, the Commission believes that maintaining this exemption may unduly place the burden of supplying reactive power on synchronous generators without a reasonable technological or cost-based distinction between synchronous and non-synchronous generators.[32]

12. Therefore, the Commission preliminarily concludes that the continued exemption from the reactive power requirement for newly interconnecting wind generators is unjust and unreasonable and unduly discriminatory and preferential. The Commission, therefore, proposes to revise the *pro forma* LGIA, Appendix G of the *pro forma* LGIA, and the *pro forma* SGIA to eliminate the exemptions for wind generators from the reactive power requirement.[33] Under this Proposal, newly interconnecting non-

---

[32] *See PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097, at P 7 (2015); *Payment for Reactive Power*, Commission Staff Report, Docket No. AD14-7, app. 1 (Apr. 22, 2014).

[33] The Commission does not propose to revise any regulatory text. The Commission proposes to revise the *pro forma* LGIA and *pro forma* SGIA in accordance with section 35.28(f)(1) of the Commission's regulations, which provides: "Every public utility that is required to have on file a non-discriminatory open access transmission tariff under this section must amend such tariff by adding the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and

(continued…)

synchronous generators would be eligible for the same payments for reactive power as other generators.[34] Any compensation would be based on the cost of providing reactive power. We note that the cost to a wind generator of providing reactive power may not be easily estimated using existing methods that are applied to synchronous generators.[35] The Commission also proposes that transmission providers that are not public utilities will have to adopt the requirements of this Proposal as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[36]

13. Removing the exemptions for wind generators from the reactive power requirement would specifically require all newly interconnecting non-synchronous generators, and all existing non-synchronous generators proposing upgrades to their generation facilities that require new interconnection requests, to design their generating

---

amending such interconnection procedures and agreements, or such other interconnection procedures and agreements as may be required by Commission rulemaking proceedings promulgating and amending the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement." 18 C.F.R. § 35.28(f)(1) (2015). *See Integration of Variable Energy Resources*, Order No. 764, FERC Stats. & Regs. ¶ 31,331, at PP 343-345 (adopting this regulatory text effective September 11, 2012), *order on reh'g and clarification*, Order No. 764-A, 141 FERC ¶ 61,232 (2012), *order on clarification and reh'g*, Order No. 764-B, 144 FERC ¶ 61,222 (2013). While not revising regulatory text, the Commission is using the process provided for rulemaking proceedings, as defined in 5 U.S.C. § 551(4)-(5) (2012).

[34] Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 416.

[35] *See Payment for Reactive Power*, Commission Staff Report, Docket No. AD14-7, app. 2 (Apr. 22, 2014).

[36] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63.

facilities to maintain reactive power within a power factor range of 0.95 leading to 0.95 lagging, or the standard range established by the transmission provider and approved by the Commission, to be measured at the Point of Interconnection.[37]

14. The Commission also proposes to require that the reactive power capability installed by non-synchronous generators be dynamic. In Order No. 661, the Commission declined to require dynamic reactive power capability from wind generators, unless the System Impact Study showed that dynamic reactive power capability was needed for system reliability, reasoning that dynamic reactive power capability may not be needed in every case.[38] Based on technological advancements, the Commission no longer believes it is just and reasonable and not unduly discriminatory or preferential to exempt wind generators from the requirement to provide dynamic reactive power.[39]

15. Further, the Commission proposes to require that newly interconnecting non-synchronous generators be required to design the generating facility to maintain the required power factor range only when the generator's real power output exceeds 10

[37] The *pro forma* LGIA defines "Point of Interconnection" as "the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission Provider's Transmission System." Similarly, the *pro forma* SGIA defines "Point of Interconnection" as "[t]he point where the Interconnection Facilities connect with the Transmission Provider's Transmission System."

[38] *See* Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 66.

[39] *Payment for Reactive Power*, Commission Staff Report, Docket No. AD14-7, at 7 (Apr. 22, 2014).

percent of its nameplate capacity.[40] In requiring a generator to provide reactive power, the interconnection agreements would state: "Non-synchronous generators shall only be required to maintain the above power factor when their output is above 10 percent of the Generating Facility Capacity." The Commission's understanding is that the inverters used by non-synchronous generators are not capable of producing reactive power when operating below 10 percent of nameplate capacity.[41]

16. Specifically, the Commission proposes to revise section 9.6.1 of the *pro forma* LGIA to read:

> Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis. ~~The requirements of this paragraph shall not apply to wind generators.~~ Non-synchronous generators shall only be required to maintain the above power factor when their output is above 10 percent of the Generating Facility Capacity.[42]

The Commission similarly proposes to revise section 1.8.1 of the *pro forma* SGIA to read:

> The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all similarly situated generators in the control area on a comparable basis. ~~The requirements of this paragraph~~

---

[40] *See* Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 46.

[41] *Id*.

[42] Section 9.6.1 of the *pro forma* LGIA.

> ~~shall not apply to wind generators.~~ Non-synchronous generators shall only be required to maintain the above power factor when their output is above 10 percent of the generator nameplate capacity.[43]

In addition, the Commission would strike paragraph A.ii of Appendix G to the *pro forma* LGIA, "Technical Standards Applicable to a Wind Generation Plant."[44]

> A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability 606 (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.[45]

17. The Commission proposes to apply the reactive power requirement to all newly interconnecting non-synchronous generators, as well as all existing non-synchronous generators making upgrades to their generation facilities that require new interconnection requests, as of the effective date of the final revision. The Commission also proposes to apply the reactive power requirement to all newly interconnecting non-synchronous

---

[43] Section 1.8.1 of the *pro forma* SGIA.

[44] The full text of the *pro forma* LGIA will be posted on the Commission's internet page at: http://www.ferc.gov/industries/electric/indus-act/gi/stnd-gen.asp. The full text of the *pro forma* SGIA will be posted on the Commission's internet page at: http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp.

[45] Section A.ii of Appendix G to the *pro forma* LGIA.

generators that have requested that an LGIA or SGIA be filed unexecuted with the Commission that is still pending before the Commission as of the effective date of the final revision. Thus, the requirement would not apply to non-synchronous generators that have executed an LGIA or SGIA, as relevant, prior to the effective date of the final revision, unless they propose upgrades to their generation facilities that require new interconnection requests. Given that not all existing wind generators are capable of providing reactive power without incurring substantial costs to install new equipment, we do not believe it is reasonable or necessary to require those generators to provide reactive power. However, existing wind generators that make upgrades to their generation facility that require a new interconnection request will be required to conform to this new requirement.

18. The Commission seeks comments on the Proposal to remove the exemptions for wind generators from the reactive power requirement. Further, the Commission seeks comments on whether the current power factor range of 0.95 leading to 0.95 lagging, as set forth in the existing *pro forma* interconnection agreements,[46] is reasonable given the technology used by non-synchronous generators. The Commission also seeks comments on the proposed requirement that newly interconnecting non-synchronous generators only be required to produce reactive power when the generator's real power output is greater than 10 percent of nameplate capacity. And finally, we note that a non-synchronous generator will be eligible for compensation for reactive power, consistent with the

[46] Section 9.6.1 of the *pro forma* LGIA and section 1.8.1 of the *pro forma* SGIA.

compensation provisions of the *pro forma* LGIA and *pro forma* SGIA.[47] The Commission seeks comment on whether the existing methods used to determine reactive power compensation are appropriate for wind generators and, if not, what alternatives would be appropriate.[48]

Proposed Compliance Procedures

19. To comply with the requirements of this Proposal, the Commission proposes to require each public utility[49] transmission provider to submit a compliance filing within 90 days of the effective date of the final revision in this proceeding revising its *pro forma* LGIA and *pro forma* SGIA subject to the Commission's jurisdiction as necessary to demonstrate that it meets the requirements set forth in this Proposal.

20. In some cases, public utility transmission providers may have provisions in their currently effective *pro forma* LGIAs and *pro forma* SGIAs related to the provision of reactive power by non-synchronous generators that the Commission has deemed to be consistent with or superior to the *pro forma* LGIA and *pro forma* SGIA. Where these *pro forma* LGIA and *pro forma* SGIA provisions will be modified by the final revision, public utility transmission providers must either comply with the final revision or

[47] Section 9.6.3 of the *pro forma* LGIA and section 1.8.2 of the *pro forma* SGIA.

[48] *See Payment for Reactive Power*, Commission Staff Report, Docket No. AD14-7, app. 1 (Apr. 22, 2014).

[49] For purposes of this Proposal, a public utility is a utility that owns, controls, or operates facilities used for transmitting electric energy in interstate commerce, as defined by the FPA. *See* 16 U.S.C. § 824(e) (2012). A non-public utility that seeks voluntary compliance with the reciprocity condition of an OATT may satisfy that condition by filing an OATT, which includes the *pro forma* LGIA and SGIA.

demonstrate that these previously-approved *pro forma* LGIA and *pro forma* SGIA variations continue to be consistent with or superior to the *pro forma* LGIA and *pro forma* SGIA as modified by the final revision.

21. The Commission will assess whether each compliance filing satisfies the proposed requirements and principles stated above and issue additional orders as necessary to ensure that each public utility transmission provider meets the requirements of this Proposal and the subsequent final revision.

22. The Commission proposes that transmission providers that are not public utilities will have to adopt the requirements of this Proposal and subsequent final revision as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[50]

Information Collection Statement

23. The collection of information contained in this Proposal to Revise Standard Generator Interconnection Agreements is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[51] OMB's regulations require approval of certain informational collection requirements imposed by an agency.[52] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject

[50] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63.

[51] 44 U.S.C. § 3507(d) (2012).

[52] 5 C.F.R. § 1320.11 (2015).

to the filing requirements will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

24. The reforms proposed in this Proposal would amend the Commission's standard generator interconnection agreements in accordance with section 35.28(f)(1) of the Commission's regulations[53] to require that each public utility transmission provider amend its *pro forma* LGIA and *pro forma* SGIA to: (1) eliminate the exemptions for wind generators from the requirement to provide reactive power; and (2) require that all newly interconnecting non-synchronous generators, as well as all existing non-synchronous generators making upgrades to their generation facilities that require new interconnection requests, provide reactive power as a condition of interconnection, as of the effective date of the final revision. The reforms proposed in this Proposal would require filings of *pro forma* LGIAs and *pro forma* SGIAs with the Commission. The Commission anticipates the reforms proposed in this Proposal, once implemented, would not significantly change currently existing burdens on an ongoing basis. With regard to those public utility transmission providers that believe that they already comply with the reforms proposed in this Proposal, they could demonstrate their compliance in the filing required 90 days after the effective date of the final revision in this proceeding. The Commission will submit the proposed reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[54]

---

[53] 18 C.F.R. § 35.28(f)(1) (2015).

[54] 44 U.S.C. § 3507(d) (2012).

25. While the Commission expects the adoption of the reforms proposed in this Proposal to provide significant benefits, the Commission understands that implementation can be a complex and costly endeavor. The Commission solicits comments on the accuracy of provided burden and cost estimates and any suggested methods for minimizing the respondents' burdens.

Burden Estimate and Information Collection Costs: The Commission believes that the burden estimates below are representative of the average burden on respondents. The estimated burden and cost[55] for the requirements contained in this Proposal follow.

[55] The estimates for cost per response are derived using the following formula: Average Burden Hours per Response * $72 per Hour = Average Cost per Response. The hourly cost figure comes from the FERC average salary of $149,489. Subject matter experts found that industry employment costs closely resemble FERC's regarding the FERC-516 information collection.

Data Collection FERC 516					
	Number of Applicable Registered Entities (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden (Hours) & Cost Per Response[56] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**
Conforming LGIA changes to incorporate proposed revisions	132	1	132	7.5 $540.00	990 hours $71,280.00
Conforming SGIA changes to incorporate proposed revisions	132	1	132	7.5 $540.00	990 hours $71,280.00
Total			264	15 hours $1,080	1,980 hours $142,560.00

Cost to Comply: The Commission has projected the total cost of compliance as follows:[57]

- Year 1: $142,560 ($1,080/utility)
- Year 2: $0

[56] $149,489 / $2,080 = $71.8697 and is rounded to $72.00 per hour.

[57] The costs for Year 1 would consist of filing proposed changes to the *pro forma* LGIA and *pro forma* SGIA with the Commission within 90 days of the effective date of the final revision plus initial implementation. The Commission does not expect any ongoing costs beyond the initial compliance in Year 1.

After Year 1, the reforms proposed in this Proposal, once implemented, would not significantly change existing burdens on an ongoing basis.

Title: FERC-516, Electric Rate Schedules and Tariff Filings.

Action: Proposed revisions to an information collection.

OMB Control No.: 1902-0096

Respondents for this Proposal: Businesses or other for profit and/or not-for-profit institutions.

Frequency of Information: One-time during year one.

Necessity of Information: The Federal Energy Regulatory Commission makes this Proposal to improve the reliability of the electric grid by requiring all newly interconnecting non-synchronous generators to provide reactive power and to ensure that all generators are being treated in a not unduly discriminatory or preferential manner.

Internal Review: The Commission has reviewed the proposed changes and has determined that such changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has specific, objective support for the burden estimates associated with the information collection requirements.

26. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873. Comments concerning the collection of information and the associated burden

estimate(s), may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-0710, fax: (202) 395-7285]. Due to security concerns, comments should be sent electronically to the following e-mail address: oira_submission@omb.eop.gov. Comments submitted to OMB should include FERC-516 and OMB Control No. 1902-0096.

Regulatory Flexibility Act Certification

27. The Regulatory Flexibility Act of 1980 (RFA)[58] generally requires a description and analysis of rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

28. To the extent the RFA applies to this proceeding, the Commission estimates that the total number of public utility transmission providers that would have to modify their currently effective *pro forma* LGIA and *pro forma* SGIA is 132. Of these, the Commission estimates the total number that are small entities is 11. The Commission estimates the average total cost of these entities will be minimal, requiring on average 15 hours, or $1,080 in expenses. The Commission does not consider this to be a significant economic impact. As a result, the Commission certifies that the reforms proposed in this

[58] 5 U.S.C. § 601-12 (2012).

Proposal would not have a significant economic impact on a substantial number of small entities.

Environmental Analysis

29. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[59] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Proposal under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[60] The revisions proposed in this Proposal would update and clarify the application of the Commission's standard interconnection requirements to wind generators. Therefore, this Proposal falls within the categorical exemptions provided in the Commission's regulations, and as a result neither an environmental impact statement nor an environmental assessment is required.

---

[59] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, 52 Fed. Reg. 47,897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

[60] 18 C.F.R. § 380.4(a)(15) (2015).

Comment Procedures

30. The Commission invites interested persons to submit comments on the matters and issues proposed in this Proposal to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**60 days after publication in the FEDERAL REGISTER**]. Comments must refer to Docket No. RM16-1-000, and must include the commenter's name, the organization they represent, if applicable, and their address.

31. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

32. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

33. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this Proposal are not required to serve copies of their comments on other commenters.

Document Availability

34. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

35. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

36. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

List of subjects in 18 C.F.R. Part 35:
Electric power rates
Electric utilities
Non-discriminatory open access transmission tariffs

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: January 29, 2016

RE: NEPOOL Scenario Analysis Proposal

At the February 5, 2016, Participants Committee meeting there will be a high level discussion of a draft NEPOOL Scenario Analysis Proposal, which is included with your materials for the February 5 meeting. By way of background, the Proposal results from NEPOOL's stated business priorities for 2016/17. Among those priorities is one that calls for scenario analyses of the implications of public policy on the wholesale markets for electricity in New England. The priority states:

> Analyses of Markets and Planning. As the only regional entity with detailed, confidential market information, ISO-NE is counted on to provide and disseminate meaningful markets and planning information. NEPOOL places a priority on ISO-NE (or its consultant) performing analysis in 2016 that reviews more completely the potential impacts of policy implications and risks on the future functioning of the existing and planned markets, following an opportunity for meaningful input from Market Participants on such a study. And, as we think about how study resources are utilized, revisiting with NEPOOL the planning criteria/assumptions that are being used both for system planning and for determining ICR would be a welcomed discussion.

The ISO included this priority in its 2016 Business Priorities presentation at the September 11, 2015 Participants Committee meeting, stating:

> Reflecting NEPOOL's priorities, ISO and regional stakeholders will consider requirements for an economic study in 2016 to review potential impacts of emerging public policy on performance of the power system and markets in New England. Study scope definition efforts, which NEPOOL and the states will need to help shape with the ISO, will need to be largely completed before the end of Q1 2016.

A first draft of the Proposal was distributed to the Participants Committee on November 19, 2015. In response, a number of stakeholders asked clarifying questions and/or provided constructive comments. Based on comments received, a substantially revised second draft of the 2016 NEPOOL Scenario Analysis proposal has been created. This draft, dated January 29, 2016, is not yet a consensus document among all those who have provided input into it thus far, but it is a starting point for further discussion at a planned special NEPOOL meeting to be held on February 16, after the Reliability Committee meeting. The intent is to have the Proposal completed by the end of March 2016, and then to present that proposal to the ISO by April 1 as an Economic Study for 2016.

If you have any questions about this project or comments about the draft proposal before or after the meeting, we encourage you to raise them with your Sector officers or with NEPOOL counsel, Eric Runge, 617-345-4735, (ekrunge@daypitney.com).

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: January 29, 2016

RE: NEPOOL Scenario Analysis Proposal

At the February 5, 2016, Participants Committee meeting there will be a high level discussion of a draft NEPOOL Scenario Analysis Proposal, which is included with your materials for the February 5 meeting. By way of background, the Proposal results from NEPOOL's stated business priorities for 2016/17. Among those priorities is one that calls for scenario analyses of the implications of public policy on the wholesale markets for electricity in New England. The priority states:

> Analyses of Markets and Planning. As the only regional entity with detailed, confidential market information, ISO-NE is counted on to provide and disseminate meaningful markets and planning information. NEPOOL places a priority on ISO-NE (or its consultant) performing analysis in 2016 that reviews more completely the potential impacts of policy implications and risks on the future functioning of the existing and planned markets, following an opportunity for meaningful input from Market Participants on such a study. And, as we think about how study resources are utilized, revisiting with NEPOOL the planning criteria/assumptions that are being used both for system planning and for determining ICR would be a welcomed discussion.

The ISO included this priority in its 2016 Business Priorities presentation at the September 11, 2015 Participants Committee meeting, stating:

> Reflecting NEPOOL's priorities, ISO and regional stakeholders will consider requirements for an economic study in 2016 to review potential impacts of emerging public policy on performance of the power system and markets in New England. Study scope definition efforts, which NEPOOL and the states will need to help shape with the ISO, will need to be largely completed before the end of Q1 2016.

A first draft of the Proposal was distributed to the Participants Committee on November 19, 2015. In response, a number of stakeholders asked clarifying questions and/or provided constructive comments. Based on comments received, a substantially revised second draft of the 2016 NEPOOL Scenario Analysis proposal has been created. This draft, dated January 29, 2016, is not yet a consensus document among all those who have provided input into it thus far, but it is a starting point for further discussion at a planned special NEPOOL meeting to be held on February 16, after the Reliability Committee meeting. The intent is to have the Proposal completed by the end of March 2016, and then to present that proposal to the ISO by April 1 as an Economic Study for 2016.

If you have any questions about this project or comments about the draft proposal before or after the meeting, we encourage you to raise them with your Sector officers or with NEPOOL counsel, Eric Runge, 617-345-4735, (ekrunge@daypitney.com).

DRAFT FOR DISCUSSION 1/29/16

NEPOOL SCENARIO ANALYSIS PROPOSAL 2016

Implications of Public Policy on ISO-NE Market Design, Reliability, Resource Metrics, Total Cost, Emissions, System Operability and Revenues of New Generation

Purpose:

The goal of the proposed NEPOOL Scenario Analysis is to provide NEPOOL Participants and regional power market stakeholders information, analyses and observations on:

(i) the potential impacts on the ISO-New England markets of implementing public policies in the New England states;

(ii) an examination of projected energy market revenues, and the contribution of those revenues to the generic fixed costs of new generation, for various generation types under particular sets of assumptions; and

(iii) the potential impacts under the status quo forecast versus the public policy overlay on reliability, resource metrics, total cost of supplying load, emissions in New England, and system operability.

Scenarios:

NEPOOL Participants, with input from ISO-NE and other regional stakeholders, will determine the specific scenarios to be modeled and the assumptions to be used.

Scenarios will be limited to a manageable number in an effort to maintain an aggressive timeline for the study results. Appropriate sensitivities applied to the scenarios are expected to provide useful information for a range of hypothetical cases. Possible variables to define scenarios to be studied include various plausible combinations of:

- Energy Consumption Growth (consumed MWh)
- Load Profiles (load shape and daily peak) that reflect behind-the-meter resources, mainly including photovoltaics ("PV") and energy efficiency ("EE")
- Fuel Supply Cost (high/low)
- Total resource mix, including retirements, additions and general locations

Five main scenarios and some basic assumptions have been discussed:

1. **Generation Fleet Meeting Existing State Renewable Portfolio Standards ("RPS"):** Beginning with the fleet of generation expected as of 2019/20, examine scenarios for the years 2025 and 2030. Use FCA#10 results and transmission system for 2020. Project net load and resources using the CELT Report (gross load, PV and EE forecasts, extrapolated out to 2030). Use EIA fuel forecasts with reasonable projections to 2030. Assume that targeted energy requirement for the New England states 2016 RPS goals will be met in

their entirety physically. Add specified assumed mix and locations of additional wind and PV resources that would meet the growth requirements of existing RPS targets.

2. **Generation Fleet Meeting Existing RPS and Retirement Replacement:** Start with the assumptions in Case 1 and examine scenarios for 2025 and 2030, assuming retirements of specified generators or use criteria for retiring generators (such as older than X years with particular fuel types). Add mix of wind and photovoltaic resources specified in Case 1.

3. **Generation Fleet Meeting Existing RPS Plus Extra:** Start with the assumptions of Case 2 and add specified hydro imports from Canada (MW, MWHRs, and location).

4. **Existing Generation Fleet with NGCC Additions:** Beginning with the fleet of generation expected as of 2019/20, examine scenarios for the years 2025 and 2030. Use FCA#10 results and transmission system for 2020. Project net load and resources using the CELT Report (gross load, PV and EE forecasts, extrapolated out to 2030). Use EIA fuel forecasts with reasonable projections to 2030. Use representative reserve margins to determine needed generation, which would be met by natural gas combined cycle ("NGCC") proxy units added at the Hub or at load centers. Assume prices for the Regional Greenhouse Gas Initiative ("RGGI") and prices for other environmental emission allowances.

5. **Existing Fleet and Retirement Replacement with NGCC Additions:** Start with assumptions in Case 4 and examine scenarios for the years 2025 and 2030, assuming retirements of specified generators or use criteria for retiring generators (such as older than X years with particular fuel types). To meet the representative reserve margins, add NGCC proxy generation as needed. Locate assumed NGCC proxy units at the Hub or brownfield sites near load where generators have been assumed to retire.

DRAFT FOR DISCUSSION 1/29/16

Deliverables:

The scenarios will be designed to provide information, analyses and observations regarding the impacts of public policies on four major areas of concern to policy makers, market participants, and consumers, potentially including the following deliverables (with ISO using outside consultant as necessary):

Reliability	Resource Metrics	Total Cost to Consumers	Emissions
1. Determination of resource mix changes and/or general transmission additions needed to maintain reliability [Note: the study will not provide specific transmission planning studies, but will identify transmission capacity needed under different scenarios and locational assumptions.]	1. Usual metrics provided in Economic Studies, including: • Production Costs • Load Serving Entity Energy Expenses • Congestion • Interface Flow Duration Curves • Generation Energy Production by Fuel Type • Environmental Air Emissions by Electric Generators	1. For each scenario, all-in costs to consumers in $/MWh	1. For each scenario, the total emissions of NOx, Sox and CO2 compared against RGGI targets/other targets
2. For each scenario the percent of annual energy requirements and installed capacity requirements met by each resource class	2. Estimated revenues from energy markets based on cost-based bidding. - Compare energy revenues with assumed annual carrying charges for representative new generating units. - Determine others potential revenue streams, such as from RECs, net metering	2. For each scenario, a breakdown of all-in cost components, including capacity, energy, reserves, and infrastructure	

	and out-of-market public policy contracts.		
	3. An analysis of the percent of total energy provided by resource type and capacity factor, and of what fuel type sets the clearing price		
	4. Percent of hours Reserve Constraint Penalty Factor estimated to set price - Calculate effect of resources on FCA clearing price		

There are two other major deliverables of the study. First the study will provide information and analysis on projected energy market revenues, and the contribution of those revenues to meeting the fixed costs of new generation, for various generation types under particular sets of assumptions, which can be used by interested persons to evaluate resource sustainability. Second, the study will provide information and analysis on the operability of the system under various scenarios and sensitivities. This operability analysis might come in a second phase of the study, depending on its difficulty and how long it will take.

Public Policies to Be Included

- RPS
- Energy Efficiency programs
- Solar programs
- Net metering programs
- State long-term renewable/clean energy procurements
- RGGI pricing

DRAFT FOR DISCUSSION 1/29/16

Tasks:

A. Further define the scenarios
B. Identify the mixes of additional conventional and renewable technology resources to be included in each scenario analysis and their respective construction costs, operating profiles or drivers, operating costs, and emissions rates
C. Agree on other assumptions to be used and sensitivities to be applied in the study
D. Agree on public policies to be modeled
E. Perform modeling and analyze the results

New England Order 745 Implementation 2011-2018

Implementation

New England Compliance

2011 Aug 19 ISO-NE submits NE Compliance Filing

2012 Jan 19 FERC cond. accepts NE Compliance Filing

2012 Mar 26 ISO-NE submits 90-day Compliance Filing

2012 May 29 FERC accepts 90-day Compliance Filing

Transition Period (TP) Implementation

2012 Jan 31 TP FCM Con-forming Changes

2012 Apr13 TP PRD Clarifications

2012 Jun 1 TP Rules Implemented

2012 Aug 20 TP PRD Energy Market Change

Full Integration (FI) Implementation

2011 Dec 22 ISO-NE moves FI Eff. Date to **Jun 1, 2016**

2012 Apr 26 FI FCM Conforming Changes FI Eff. Date moved to **Jun 1, 2017**

2013 Jan 14 FERC cond. accepts Apr 26 FI FCM Changes

2013 Mar 15 FI FCM Compliance Filing

2014 Mar 12 FERC accepts Mar 15 2013 FI FCM Compliance Filing

2018 Jun 1 FI Rules to be implemented

2013 Jun 21 FI PRD Changes

2013 Aug 20 FERC accepts FI PRD Changes

2014 Oct 31 FI PRD Reserve Changes

2015 Jan 9 FERC accepts FI PRD Reserve Changes

2015 Oct 29 DR Baseline, Auditing Changes FI Eff. Date moved to **Jun 1, 2018**

2015 Dec 23 FERC accepts Oct 29 Changes; **Jun 1, 2018** FI Eff. Date

2011 2012 2013 2014 2015 2016 2017 2018

Legal Challenges

New England Order 745 Compliance

2012 Feb 21 Jan 19 Order Rehearing Requests

2012 May 17 FERC denies Rehearing Requests

2012 Jul 16 NEPGA/EPSA Appeal NE Orders to DC Cir.

2012 Aug 23 DC Cir. grants motion to hold case in abeyance pending outcome of Order 745 Appeal

2014 Nov 24 NEPGA FCA9 DR Capacity Complaint

2016 Jan 29 NEPGA withdraws FCA9 DR Capacity Complaint

FERC Order 745

2011 Mar 15 FERC issues Order 745

2011 Dec 15 FERC issues Order 745-A

2011 Dec 23 EPSA 745/745-A Appeal to DC Circuit

2014 May 23 DC Circuit Vacates Order 745

2015 Jan 15 Solicitor Gen. writ of certiorari to SCOTUS

2015 May 4 SCOTUS grants certiorari

2016 Jan 25 SCOTUS reverses DC Circuit Decision

2/4/2016

DAY PITNEY LLP

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings as of February 4, 2016 (3pm)

The following activity, as more fully described in the attached litigation report, has occurred since the report dated January 6, 2016 was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

1	206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)	Jan 11 Jan 19 Jan 22 Jan 27	Chief Judge Cintron designates Judge Dring as settlement judge First settlement conf. Settlement Judge Dring schedules 2nd settlement conf. for Mar 24 VEC requests rehearing of Dec 28 order as to the inclusion of it and its non-jurisdictional LNS rates in this proceeding
2	206 Proceeding: Zonal Sloped Demand Curves (EL16-15)	Jan 7- Jan 19 Jan 27 Feb 3	NEPOOL, Champlain VT, CT DEEP, MA AG, MPUC, National Grid, NH OCA, API, APPA, intervene NEPOOL, ISO-NE, NESCOE jointly request extension of time, to Apr 15, 2016, for changes in response to the Dec 28 Order FERC grants extension of filing of changes to Apr 15, 2016
2	206 Proceeding: 2014/15 RNS Recovery of SeaLink Development Costs (EL15-85)	Jan 8 Feb 3	Trial Judge Baten issues order setting procedural schedule; Trial to begin Jul 19; Initial Decision due Nov 1, 2016 NHT files initial direct testimony, exhibits and workpapers
3	New Entry Pricing Rule Complaint (EL15-23)	Jan 7	FERC denies rehearing of *New Entry Pricing Rule Complaint Order*
4	NEPGA DR Capacity Complaint (EL15-21)	Jan 29	NEPGA withdraws Complaint in light of Supreme Court decision in *FERC v. EPSA*
4	Base ROE Complaints (2012 and 2014) Consolidated (EL13-33 and EL14-86)	Jan 15 Jan 20 Jan 27 Jan 28	TOs and FERC Staff file supplemental expert testimonies Consumer-Aligned Parties file supplemental expert testimony TOs move to strike Jan 20 supplemental expert testimony Consumer-Aligned Parties oppose TOs' Jan 27 motion to strike

II. Rate, ICR, FCA, Cost Recovery Filings

5	ICR-Related Values and HQICCs - 2016/17 ARA3, 2017/18 ARA2, 2018/19 ARA1 (ER16-446)	Jan 29	Entergy, Eversource, National Grid, PSEG intervene Dominion, NEPGA, NRG file protests; NESCOE files comments ISO-NE answers Dominion, NEPGA, NRG protests
6	FCA10 Qualification Informational Filing (ER16-308)	Jan 21	FERC accepts filing; denies Lotus Energy Group request for revision of the New Resource Offer Floor Price for its projects
6	ICR, HQICCs and Related Values - 2019/20 Power Year (ER16-307)	Jan 8	FERC accepts 2019/20 ICR, HQICC, and LSR Values

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

8	Lotus Energy FCA10 Waiver Request (EL16-22)	Jan 7-21 Jan 19 Jan 21 Jan 28 Feb 2	APPA, Champlain VT, ConEd, National Grid, NEPGA intervene NEPOOL files limited comments ISO-NE, NRG file protests Lotus answers ISO-NE, NRG answers; makes emergency motion for FERC to delay start of FCA10 until after FERC acts on Request Lotus withdraws Waiver Request

*	9	New DNE Dispatch Changes Effective Date (ER16-870)	Feb 2	ISO-NE files to establish May 25, 2016 as the new effective date for the DNE Dispatch Changes; comment date Feb 23
*	9	CSO Termination: Spruce Mountain Wind (ER16-864)	Feb 1	ISO-NE files to terminate a portion of Spruce Mountain Wind's CSO for Resource 38173; comment date Feb 22
			Feb 3	NEPOOL intervenes
*	9	Waiver Request: FCM Qualification Lock-In Election (Calpine) (ER16-708)	Jan 8	Calpine requests waiver of FCM qualification rules to allow it to correct an inadvertently omitted lock-in election
			Jan 14	NEPOOL intervenes
			Jan 19	PSEG protests waiver request
			Jan 20	NESCOE, Westfield support waiver request
			Feb 4	FERC grants waiver request
	10	FCM Resource Retirement Reforms (ER16-551)	Jan 11	Dominion, GEN Group, NEPGA, NRG, PSEG file protests; NESCOE files supportive comments
			Jan 27	ISO-NE, Eversource answer protests
			Feb 1	Potomac Economics (EMM) moves to intervene out-of-time, supports ISO/IMM Proposal with 3 recommended changes
	10	De-List Bid Information Release Change (ER16-538)	Feb 2	FERC accepts change, eff. Feb 14, 2016
	11	CTS Winter Reliability Program Cost Allocation Correction (ER16-462)	Jan 28	FERC accepts correction, eff. Dec 15, 2015

IV. OATT Amendments / TOAs / Coordination Agreements

*	12	RSP Timing Changes (ER16-819)	Jan 29	ISO-NE and NEPOOL file changes to timing of full RSP report (once every 2 years, rather than annually); comment date Feb 19
			Feb 1-4	NESCOE, National Grid intervene

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

*	12	Schedule 21-EM: Covanta Maine LTSA Terminations (ER16-840)	Jan 29	Emera files notice of termination of two expired LTSAs with Covanta Maine; comment date Feb 19
*	13	Schedule 21-NSTAR: Fore River LGIA Termination	Jan 29	Eversource files notice of termination of prior Fore River LGIA (since replaced by 3-party LGIA; comment date Feb 19

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	13	Opinions *531-A/531-B* Local Refund Reports (EL11-66)	Jan 8	Emera Maine files local refund report; comment date Jan 29
			Jan 11	UI supplements Dec 31 report; comment date Feb 1
			Jan 13	VT Transco files local refund report; comment date Feb 3
*	13	LFTR Implementation: 29th Quarterly Status Report (ER07-476)	Jan 15	ISO-NE files its 29th quarterly report
*	14	IMM Quarterly Markets Reports - 2015 Fall (ZZ15-4)	Jan 29	ISO-NE files 2015 Fall Report

IX. Membership Filings

*	14	February 2016 Membership Filing (ER16-836)	Jan 29	Membership: GBE Power; Terminations: Glacial, Parkview AMC, Vermont Marble; Name Change: Constellation Energy Power Choice, LLC; comment date Feb 19
*	14	Involuntary Termination of Membership: NAPP (ER16-820)	Jan 29	NEPOOL and ISO-NE file to involuntarily terminate NAPP's NEPOOL and Market Participant status; comment date Feb 19
*	14	Involuntary Termination of Membership: Negawatt (ER16-818)	Jan 29	NEPOOL and ISO-NE file to involuntarily terminate Negawatt's NEPOOL and Market Participant status; comment date Feb 19
*	14	Suspension Notices (not docketed)	Jan 26	Lotus Danbury LMS100 One and Two suspended from New England Markets
			Jan 27	ISO-NE files notice of Lotus Danbury suspensions

X. Misc. - ERO Rules, Filings; Reliability Standards

	15	Glossary Definition Changes (RD16-3)	Jan 21	FERC approves changes to 26 defined terms in the Reliability Standards Glossary
*	15	New Reliability Standard: BAL-002-2 (RM16-7)	Jan 29	NERC files BAL-002-2 for approval
	15	*Order 822*: Revised CIP Reliability Standards (RM15-14)	Jan 21	FERC approves Supply Chain Cyber Controls Changes, eff. Mar 31, 2016
			Jan 28	Technical conference on supply chain risk management issues held
	18	Rules of Procedure Changes (RR16-2)	Jan 21	FERC approves changes to NERC's Rules of Procedure

XI. Misc. - of Regional Interest

	19	203 Application: Calpine/Granite Ridge (EC16-19)	Jan 28	FERC approves proposed transaction
	19	PURPA Complaint: Allco Renewable Energy v. CT Agencies (EL16-11 et al.)	Jan 8	FERC issues notice of intent not to initiate Allco-requested PURPA enforcement action; Allco may itself bring an enforcement action against CT DEEP and CT PURA in the appropriate court
	20	FirstEnergy PJM DR Complaint (EL14-55)	Jan 29	FirstEnergy withdraws Complaint in light of Supreme Court decision in *FERC v. EPSA*
*	20	Cost Sharing Agreements re: Greater Boston Area Transmission Solution Plan (ER16-878 et al.)	Feb 3	NSTAR, PSNH, NGrid file Cost Sharing Agreement for the Greater Boston Area Transmission Solution Plan; comment date Feb 24
*	20	LGIA: National Grid/Wheelabrator Saugus (ER16-760)	Jan 21	National Grid files LGIA with Wheelabrator Saugus; comment date Feb 11
	20	SGIA: CMP/Hackett Mills Hydro (ER16-518)	Jan 20	CMP files correction and supplement to SGIA with Hackett Mills Hydro; comment date Feb 10
	21	D&E Agreement NSTAR/NRG Canal 3 (ER16-510)	Feb 2	FERC accepts Agreement, eff. Dec 11, 2015
	21	D&E Agreement NSTAR/Exelon West Medway (ER16-509)	Feb 2	FERC accepts Agreement, eff. Dec 11, 2015
	21	LGIA – PSNH/Schiller Generating Station (ER16-391)	Jan 11	FERC accepts LGIA, eff. Jan 1, 2016

	21	Emera MPD OATT Changes (ER15-1429; EL16-13)	Jan 12 Jan 20 Jan 21	Judge Johnson issues status report, notice of Mar 3, 2016 second settlement conference Emera Maine moves for adoption of protective order Chief Judge Cintron issues order adopting protective order
	23	FERC Enforcement Action: Show Cause Order – Coaltrain et al. (IN16-4)	Jan 29 Feb 1	Respondents request extension of time, to Mar 4, 2016, to file answer FERC issues notice extending time for filing of Respondents' answer to Mar 4, 2016
	24	Etracom & M. Rosenberg (IN16-2)	Jan 14	Etracom invokes statutory rights to prompt assessment of a penalty and a *de novo* review of that penalty in federal district court should FERC assess penalties following response to Show Cause Order

XII. Misc. - Administrative & Rulemaking Proceedings

*	24	Clean Power Plan Modeling Guidance Principles (AD16-14)	Jan 19 Jan 20	FERC issues staff white paper FERC issues errata to white paper
	25	Price Formation in RTO/ISO Energy and Ancillary Services Markets (AD14-14)	Jan 15 Jan 27	ISO/RTO Council requests extension of time, to Mar 4, 2016, for ISO/RTO responses FERC grants extension of time; ISO/RTO responses due Mar 4; public comments on responses, Apr 4
*	25	NOPR: Price Formation Fixes - Price Caps in RTO/ISO Markets (RM16-5)	Jan 21	FERC proposes to require each RTO/ISO to cap incremental energy offers to the higher of $1,000/MWh or a resource's verified cost-based offer (regardless of fuel-type); comment date Apr 4
	25	NOPR: Reactive Power Requirements for Wind Generators (RM16-1)	Jan 27	Over 20 parties submit comments; NEPOOL submits initial comments (to be supplemented following Feb 5 NPC meeting)
	26	NOPR: Connected Entity Data Collection (RM15-23)	Jan 7 Jan 20-28	Public Citizen submits partial opposition to Industry Groups' request Over 50 parties submit comments

XIII. Natural Gas Proceedings

	28	Section 5 Investigations: Columbia (RP16-302); Empire (RP16-300); Iroquois (RP16-301); Tuscarora (RP16-299)	Jan 21 Jan 27	FERC issues orders initiating Natural Gas Act Section 5 investigations into whether the rates charged by the named gas pipeline companies were too high above their costs under federal law Acting Chief ALJ Cintron designates presiding ALJs for each of the proceedings

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

*	34	NEPGA Peak Energy Rent (PER) Complaint (16-1024**)	Jan 19 Jan 25	NEPGA appeals FERC's order on its PER Complaint Clerk issues order regarding appearances and initial submissions
*	34	FCM Jump Ball and Compliance Proceedings (16-1023**)	Jan 19	NEPGA appeals FERC's orders in the FCM Jump Ball and Compliance proceedings; clerk issues order regarding appearances and initial submissions
	35	*Order 1000* Compliance Filings (15-1139, 15-1141**) (consolidated)	Jan 11	Joint Petitioner Briefs filed
	38	*Orders 745 and 745-A* (*FERC v. EPSA*, Supreme Court, 14-840 and 14-841)	Jan 25	Supreme Court overturns DC Circuit Court of Appeals' Decision vacating *Order 745*

M E M O R A N D U M

TO: NEPOOL Participants Committee Member and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: February 4, 2016

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 February 4, 2016. If you have questions, please contact us.[1]

I. Complaints/Section 206 Proceedings

- **206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19)**

As previously reported, the FERC instituted this Section 206 proceeding on December 28, 2015, finding that the ISO Tariff is unjust, unreasonable, and unduly discriminatory or preferential because the Tariff "lacks adequate transparency and challenge procedures with regard to the formula rates" for Regional Network Service ("RNS") and Local Network Service ("LNS").[2] The FERC also found that the RNS and LNS rates themselves "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" because (i) "the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates" and "could result in an over-recovery of costs" due to the "the timing and synchronization of the RNS and LNS rates".[3] Accordingly, the FERC established hearing and settlement judge procedures to develop just and reasonable formula rate protocols to be included in the ISO-NE Tariff and to examine the justness and reasonableness of the RNS and LNS rates. The FERC encouraged the parties to make every effort to settle this matter before hearing procedures are commenced.[4] Hearings will be held in abeyance pending the outcome of settlement judge procedures.[5] The FERC-established refund date is January 4, 2016.[6] Interventions were due February 3, 2016. Interventions were filed by NEPOOL, the ISO, Braintree, Chicopee, Champlain VT, CT AG, CT DEEP, CT OCC, CT PURA, CMEEC, Fitchburg, Green Mountain, Liberty Utilities, MA AG, MA DPU, Maine Office of Public Advocate ("MOPA"), Middleborough, MMWEC, MPUC, Nat'l Grid, NESCOE, NHEC, NH OCA, Norwood, Public Citizen, Reading, RI PUC, Taunton VEC, VELCO, VPSA, VT DPS, Wallingford, and APPA.

Request for Rehearing. On January 27, Vermont Electric Cooperative ("VEC") requested rehearing of the December 28 order. Specifically, VEC asserted that, because VEC is not a public utility, the FERC has no

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

[2] *ISO New England Inc. Participating Transmission Owners Admin. Comm. et al.*, 153 FERC ¶ 61,343 (Dec. 28, 2015), *reh'g requested*.

[3] *Id.* at P 8.

[4] *Id.* at P 11.

[5] *Id.*

[6] The notice of this proceeding was published in the *Fed. Reg.* on Jan. 4, 2016 (Vol. 81, No. 1) p. 89.

power under Section 206 of the Federal Power Act ("FPA") to institute a proceeding against it. In addition, VEC asserted that by directing an investigation of VEC's LNS rate, the FERC also exceeded its authority, as VEC's LNS rate is not a pass through rate that is administered or charged by the ISO. The VEC request for rehearing is pending before the FERC, with FERC action required on or before February 26, 2016, or the VEC request will be deemed denied.

Settlement Judge Procedures. On January 11, Chief Judge Cintron designated Judge John P. Dring as the Settlement Judge and scheduled a first settlement conference, which was held January 19. On January 22, Judge Dring issued an order scheduling a second settlement conference for March 24.

- **206 Proceeding: Zonal Sloped Demand Curves (EL16-15)**

Also on December 28, 2015, the FERC instituted a Section 206 proceeding finding that the ISO Tariff is unjust, unreasonable, and unduly discriminatory or preferential because the Tariff "applies vertical demand curves within constrained zones, which does not sufficiently address concerns such as price volatility and a susceptibility to the exercise of market power as part of the Forward Capacity Market ("FCM") rules.[7] The FERC directed the ISO to submit Tariff revisions "that provide for inclusion of zonal sloped demand curves in its FCM rules, to be implemented beginning with FCA 11."[8] Finding that "concerns with continued use of vertical demand curves weigh more heavily than they did a year ago",[9] and that "the general challenges cited by ISO-NE [explaining the delay in developing zonal sloped demand curves] do not justify further delay",[10] the FERC directed that Tariff changes be filed, following a request for extension granted, by ***April 15, 2016***.[11] Interventions in EL16-15 were due January 19. Interventions were filed by the ISO, NEPOOL, Calpine, Champlain VT, CT DEEP, CT OCC, CT PURA, EPSA, Essential Power, Exelon, MA AG, MPUC, National Grid, NEPGA, NESCOE, NH OCA, Public Citizen, TransCanada, and the American Petroleum Institute ("API"), American Public Power Association ("APPA"). On January 27, NEPOOL, the ISO and NESCOE jointly requested an extension of time, to April 15, 2016, to file changes in response to the December 28 order in this proceeding. That request was granted on February 3. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **206 Proceeding: 2014/15 RNS Recovery of SeaLink Development Costs (EL15-85)**

The hearing process in this proceeding is underway. As previously reported, after settlement judge proceedings were terminated, Chief Judge Cintron designated ALJ Philip Baten as the trial judge in this proceeding, and, ultimately, established Track II procedural time standards for the hearing. On January 8, 2016, Judge Baten issued an order setting the procedural schedule for the hearing process, with hearing set to commence July 19, 2016 and an initial decision due November 1, 2016. Since the last Report, NHT filed, on February 2, its initial direct testimony, exhibits and workpapers. Intervenors' direct and answering testimony (with summaries), exhibits and workpapers are due March 2, 2016.

---

[7] *ISO New England Inc. et al.*, 153 FERC ¶ 61,338 (Dec. 28, 2015).

[8] *Id.* at P 11.

[9] *Id.* at P 15.

[10] *Id.* at P 14.

[11] *Id.* at P 16. The original compliance filing date, March 31, 2016, was slightly accelerated from the tentative schedule identified by the ISO in its Oct. 30, 2015 informational report in ER14-1639. That Report summarized a schedule contemplating Participants Committee consideration of a zonal demand curve proposal at the NPC's April 2016 meeting, with a FERC filing shortly thereafter. *See* Dec. 2, 2015 Litigation Report, Section VIII, Demand Curve Changes Progress Reports (ER14-1639) at p. 17. The compliance filing date was subsequently extended to April 15, 2016, to allow for a vote at the April 8, 2015 NPC meeting.

Background. On August 12, 2015, the FERC issued an order accepting the TOs' July 31, 2014 informational rate filing but, in response to a protest by "Public Representatives",[12] instituted a Section 206 proceeding in Docket EL15-85 to examine whether the recovery by New Hampshire Transmission ("NHT") of SeaLink project development costs through the RNS formula rate is just and reasonable.[13] The FERC encouraged the parties to make every effort to settle their dispute before hearings were commenced, and held the hearings in abeyance pending the outcome of settlement judge procedures.[14] The FERC-established refund effective date is August 19, 2015.[15] On December 11, Public Representatives requested the following two clarification of the *August 12 Order*: (i) that, in establishing the August 19, 2015 refund effective date, the FERC "did not intend to preclude the ability to order refunds for past periods if it is found that a formula rate has been misapplied"; and (ii) that, in establishing an FPA Section 206 proceeding, the FERC did not intend to relieve NHT of its obligation to demonstrate that its Sealink planning costs "are properly recoverable under the formula rate on file with the [FERC]." On December 14, NHT filed a response taking no position on whether the FERC should provide the requested clarifications, but should it, stating no objection to the FERC making the clarifications requested. Public Representatives' request for clarifications is pending before the FERC. If there are questions on these proceedings, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **New Entry Pricing Rule Complaint (EL15-23)**

On January 7, the FERC denied Exelon's and Calpine's request for rehearing[16] of the FERC's January 30 order denying the New Entry Pricing Rule Complaint.[17] 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 asserted, 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.

In its *New Entry Pricing Rule Rehearing Order*, the FERC disagreed with Exelon/Calpine's assertion that it had failed to provide a reasoned basis for finding that the New Entry Pricing Rule, coupled with the lock-in requirement, is just and reasonable or that it failed to address their arguments regarding artificial price suppression in the entry FCA.[18] In addition, the FERC stated that its opinion regarding whether zero-price offers from locked-in resources may be just and reasonable had evolved. Based on further consideration, the FERC has come to realize that a zero-price capacity offer from a new merchant resource that has cleared in at least one previous auction and has incurred construction costs can be a competitive offer that reflects the resource's going-forward costs, not an attempt to lower capacity market clearing

---

[12] "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").

[13] *ISO New England Inc. Participating Transmission Owners Administrative Committee and New Hampshire Transmission, LLC*, 152 FERC ¶ 61,121 (Aug. 12, 2015) ("*August 12 Order*").

[14] *Id.* at P 20.

[15] The notice of this proceeding was published in the *Fed. Reg.* on Aug. 19, 2015 (Vol. 80, No. 160) p. 50,271.

[16] *Exelon Corp. and Calpine Corp. v. ISO New England Inc.*, 154 FERC ¶ 61,005 (Jan. 7, 2016) ("*New Entry Pricing Rule Rehearing Order*").

[17] 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 denied*, 154 FERC ¶ 61,005 (Jan. 7, 2016).

[18] *New Entry Pricing Rule Rehearing Order* at P 15.

prices.[19] Unless the *New Entry Pricing Rule Rehearing Order* is challenged in Federal Court, this proceeding will be concluded. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **NEPGA DR Capacity Complaint (EL15-21)**

On January 29, 2016, in light of the Supreme Court ruling in *FERC v. EPSA* overturning the DC Circuit Court of Appeals' decision vacating *Order 745* (*see* Section XV below), NEPGA withdrew its November 14, 2014 Complaint. As previously reported, the Complaint requested 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 the DC Circuit Court of Appeals' reversal of *Order 745*). If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Base ROE Complaints (2012 and 2014) Consolidated (EL13-33 and EL14-86)**

As previously reported, the FERC, in response to second (EL13-33[20]) and third (EL14-86[21]) 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;[22] the second, in EL14-86, was issued on November 24, 2014, established a 15-month refund period beginning July 31, 2014,[23] 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."[24] The TOs requested rehearing of both orders. On May 14, the FERC denied rehearing of both orders.[25] On July 13, the TOs appealed those order to the DC Circuit Court of Appeals (see Section XIV below).

Hearings. The hearings in this matter 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

---

[19] *Id*. at P 18.

[20] The 2012 Base ROE Complaint, filed by Environment Northeast (now known as Acadia Center), 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%.

[21] 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.

[22] *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).

[23] *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).

[24] *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).

[25] *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).

July 13, 2015. Judge Sterner adopted the transcript corrections on July 15. On July 29, 2015, a Joint Procedural History was submitted, as were initial briefs by the Complainant-Aligned Parties, TOs, EMCOS and FERC Staff. On August 26, 2015, Reply Briefs were submitted by the Complainant-Aligned Parties, TOs, EMCOS and FERC Staff , as was a Joint List of Appearances. On December 18, 2015, finding none of the parties performed the discounted cash flow ("DCF") methodology in accordance with the FERC's preferred approach, Trial Judge Sterner reopened the record for the limited purpose of having calculations re-run based on data already in the record as of the close of hearing on July 2, 2015, so that the zone of reasonableness and ROE could be established in both cases. Judge Sterner scheduled a January 5 prehearing conference for the purpose addressing questions and completing the remainder of the procedural schedule. Also on December 18, Chief Judge Cintron set the deadline for supplemental reply briefs and a new deadline for Judge Sterner's Initial Decision at March 1 and March 31, 2016, respectively.

Since the last Report and in accordance with Judge Sterner's January 5 procedural order, TOs and FERC Staff filed the supplemental testimonies of their expert witnesses on January 15; Consumer-Aligned Parties, January 20. On January 27, the TOs' moved to strike Consumer-Aligned Parties' supplemental expert testimony. The Consumer-Aligned Parties opposed the TOs' motion to strike on January 28. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Base ROE Complaint (2011) Refund Reports (EL11-66)**

On November 2, the TOs submitted a refund report documenting resettlements of regional transmission charges by the ISO in compliance with *Opinions No. 531-A*[26] *and 531-B.*[27] As previously reported, following the issuance of *Opinion 531-B*, which denied rehearing of *Opinion 531*[28] and *Opinion 531-A*, the TOs requested an extension of time to permit the following deadlines in connection with refunds resulting from *Opinion No. 531-B*: August 31, 2015, for regional refunds; October 31, 2015, for the regional refund report; October 31, 2015, for local refunds; and December 31, 2015, for the final local refund report. The TOs submitted the additional local refund reports at the end of December (*see* Section VIII below). Other than action on the filed local refund reports, and absent a successful challenge in the federal courts (*see* Section XV below), these proceedings are concluded. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **ICR-Related Values and HQICCs - 2016/17 ARA3, 2017/18 ARA2, 2018/19 ARA1 (ER16-446)**

On January 29, 2016, the FERC accepted materials identifying the Installed Capacity Requirement ("ICR"), Local Sourcing Requirements ("LSR"), Maximum Capacity Limits ("MCL") (collectively, the "ICR-Related Values") and Hydro Quebec Interconnection Capability Credits ("HQICCs") for the System-Wide Demand Curve for the third annual reconfiguration auction ("ARA") for the 2016/17 Capability Year to be held March 1, 2016, the second ARA for the 2017/18 Capability Year to be held August 1, 2016, and the first ARA for the 2018/19 Capability Year to be held June 1, 2016.[29] The ICR-Related Values and HQICCs were accepted effective as of January 30, 2016, as requested. As previously reported, protests were filed by Dominion (limited to the ISO's new methodology for incorporation in the load forecast of predicted future amounts of behind-the-meter photovoltaic resources that have not been captured in historical loads

[26] *Martha Coakley, Mass. Att'y Gen. et al.*, 149 FERC ¶ 61,032 (Oct. 16, 2014) ("*Opinion 531-A*").

[27] *Martha Coakley, Mass. Att'y Gen. et al.*, Opinion No. 531-B, 150 FERC ¶ 61,165 (Mar. 3, 2015) ("*Opinion 531-B*").

[28] *Martha Coakley, Mass. Att'y Gen. et al.*, 147 FERC ¶ 61,234 (June 19, 2014) ("*Opinion 531*"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014), *reh'g denied*, 150 FERC ¶ 61,165 (Mar. 3, 2015).

[29] *ISO New England Inc. and New England Power Pool Participants Comm.*, 154 FERC ¶ 61,057 (Jan. 29, 2016).

("BTMNEL")), NEPGA (on the basis that the ISO has yet to consider and vet with NEPOOL stakeholders the potential market and operational effects of its proposed change in ICR methodology, and because the ISO seeks to make change its ICR methodology without filing Tariff language under FPA Section 205), and NRG (objecting, as it did in ER16-307, to the use of forecasted values and forecasted performances in the calculation of reserve requirements, including the use of BTMNEL, and asserting that the changes to the ICR methodology must be filed under Section 205). NESCOE submitted comments (incorporating by reference its comments supporting the inclusion of the solar PV forecast as an input into the ICR determination filed earlier in ER16-307). Interventions were filed by Entergy, Eversource, National Grid, and PSEG. On January 5, 2016, the ISO answered the Dominion, NEPGA, and NRG protests. In accepting the ICR-Related Values, the FERC rejected the challenges, noting the challenges were addressed in the *2019/20 ICR/HQICCs Order* (*see* ER16-307 just below). Unless the January 29 order is challenged, with any challenges due on or before February 29, 2016, this proceeding will be concluded. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA10 Qualification Informational Filing (ER16-308)**

On January 21, 2016, the FERC accepted the ISO's informational filing for qualification in FCA10 (the "FCA10 Informational Filing").[30] As previously reported, The FCA10 Informational Filing contained the ISO's determinations that two Capacity Zones, Southeastern New England ("SENE") and Rest of Pool, will be modeled for FCA10. SENE will be modeled as import-constrained Capacity Zones; no export-constrained Capacity Zones will be modeled (and, accordingly, no Maximum Capacity Limits ("MCLs") were established). The Informational Filing reported that there will be 33,411 MW of existing capacity in FCA9 competing with 6,720 MW of new capacity under a procurement limit of 34,151 MW (ICR minus HQICCs). The ISO reported also that there were a total of 1,382 MW of Static De-list bids, 97 MW of which were later converted into Non-Price Retirement Requests. A summary of the De-list bids accepted and those rejected for reliability purposes was included in a privileged Attachment E. In response to the FCA10 Information Filing, Lotus Energy Group submitted a limited protest, requesting that the ISO be directed to revise the New Resource Offer Floor Price for its projects, by reflecting what it asserts is the correct cost of equity for the projects. In accepting the FCA10 Informational Filing, the FERC denied Lotus's request, "unpersuaded by Lotus's assertion that ISO-NE evaluated the Offer Floor Price for the Projects based on an unreasonably high cost of equity figure,"[31] declining to overrule "ISO-NE's judgment as to whether Lotus had substantiated its position as to the correct cost of equity figure without any evidentiary support",[32] and agreeing with ISO-NE that "granting the requested waiver would be harmful to other participants."[33] Unless the *FCA10 Qual. Informational Filing Order* is challenged, with any challenges due on or before February 22, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ICR-Related Values and HQICCs - 2019/20 Power Year (ER16-307)**

On January 8, 2016, the FERC accepted the ICRs, Hydro Quebec Interconnection Capability Credits ("HQICCs") and related Local Sourcing Requirements ("LSR") values for the 2019/20 Capability Year.[34] As previously reported, the values will be used in FCA10 to be held this month. With a 2019/20 ICR of 35,151 MW (reflecting tie benefits of 1,990 MW) and HQICCs of 975 MW/mo., the net amount of capacity to be purchased in FCA9 to meet the ICR will be 34,151 MW. The LSR for the SENE Capacity Zone is 10,028. The 1-in-5 Loss of Load Expectation ("LOLE") and 1-in-87 LOLE capacity requirement values for the Demand Curve are 33,076 MW and 37,053 MW, respectively. In accepting the 2019/20 values, the FERC noted "that ISO-NE followed the Commission's expectation that ISO-NE would work with its stakeholders to address the incorporation of solar PV

[30] *ISO New England Inc.*, 154 FERC ¶ 61,041 (Jan. 21, 2016) ("*FCA10 Qual. Informational Filing Order*").

[31] *Id.* at PP 23-24.

[32] *Id.* at P 25.

[33] *Id.*

[34] *ISO New England Inc.*, 154 FERC ¶ 61,008 (Jan. 8, 2016) ("*2019/20 ICR/HQICCs Order*").

forecasts into the ICR calculation for FCA 10."[35] The FERC found that the ISO "properly incorporated Non-Embedded Solar Resources into its ICR calculation, and has supported that action," dismissing arguments made by protesters to the contrary."[36] With respect to protests regarding the underlying stakeholder process, the FERC found that, "while those discussions did not result in NEPOOL's support of ISO-NE's proposed ICR, [ ] the stakeholder process … provided sufficient process, and, contrary to NEPGA's assertion in its answer, considered the operational and market consequences of its change to its method of calculating the ICR."[37] Challenges to the *2019/20 ICR/HQICCs Order*, if any, are due on or before February 8, 2016. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Eversource CCRP Cost Treatment Proposal (ER16-116)**

As previously reported, Eversource submitted, on October 19, 2015, a proposal to treat $15.7 million incurred in connection with the Central Connecticut Reliability Project ("CCRP") as capital costs of the New England East-West Solution ("NEEWS") transmission project. As part of its proposal, Eversource proposes to forgo the two ROE incentive adders that the FERC granted to the NEEWS Project (i.e., the 125 basis points for new transmission under *Order 679* and 50 basis points for participation in an RTO), given this component was redesigned and subsumed into a successor transmission project that does not have transmission incentives under *Order 679*. The proposal included changes to OATT Attachment F and the Attachment F Implementation Rule. Eversource stated that its proposal will have a rate reduction effect. Eversource requested an April 16, 2015 effective date (the date on which ISO-NE approved the Greater Hartford and Central Connecticut Project and Eversource withdrew its original CCRP PPAs from consideration in the RSP). Comments on this filing were due on or before November 9, 2015; none were filed. Doc-less interventions were filed by NESCOE, MA AG, and National Grid.

On December 16, the FERC issued a deficiency letter, indicating that additional information identified in the deficiency letter is required for the filing to be processed. The FERC directed that the response to the deficiency letter be submitted on or before January 15, 2016. In addition to the deficiency letter response, the FERC directed Eversource to have the ISO re-submit the proposed revisions to Attachment F to recover the CCRP costs based on the current effective version of the ISO Tariff (finding the Tariff revisions submitted did not reflect the currently effective version of Attachment F accepted by the FERC in ER15-1629, effective June 1, 2015). On December 24, Eversource requested an extension of time, to February 15, 2016, to submit the additional information. On December 31, the FERC granted an extension of time, to February 15, 2016, as requested, for Eversource's response to the deficiency letter. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA1 Results Remand Proceeding (ER08-633)**

As previously reported, the DC Circuit issued on December 23, 2011, a *per curium* order[38] that PSEG's May 2010 petition for review be granted, remanding the FERC's orders in this proceeding[39] 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 any contrary result would result in "undue discrimination" and would be "inconsistent with the fundamental policy goals" of FCM.

---

[35] *Id.* at P 27.

[36] *Id.* at PP 30-37.

[37] *Id.* at P 37.

[38] *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).

[39] *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).

In a long-awaited order, the FERC, on June 2, 2015, 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.[40] "[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."[41] 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 paid (the resource's Lead Market Participant during each month of FCA1); 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. A reply brief was submitted on August 17 by Bridgeport Energy (requesting that payments be paid to the legal entity that owned the resource at the time of the FCA 1 Commitment Period or, if that legal entity no longer exists, to the successor in interest to ownership of the subject resource). On September 2, the ISO answered Bridgeport Energy's reply brief, advocating for resettlement payments to the Lead Market Participant during the first Capacity Commitment Period. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

- **Lotus Energy Waiver Request (EL16-22)**

On February 2, Lotus withdrew its Waiver Request/Complaint. As previously reported, in a December 22 motion filed under Section 206 of the FPA, Lotus Energy Group, LLC ("Lotus") requested a waiver of the application of the existing New Resource Offer Floor Price rules to its two generating facilities currently under development (the "Projects"). Lotus stated that it did not seek the adoption of a generically applicable exemption

[40] *ISO New England Inc.*, 151 FERC ¶ 61,196 (June 2, 2015) ("*FCA1 Remand Order*").

[41] *Id.* at P 14.

from those rules and does not seek to change any Market Rules.[42] Rather, it sought an order that allows the Projects to avoid be subject to mitigation under the Tariff, mitigation which Lotus asserts would be "unjust, unreasonable, and directly contrary to [FERC] policy and precedent". Comments on the Lotus Complaint were due on or before January 21. Interventions were filed by APPA, Calpine, Champlain ConEd, VT, Entergy, National Grid, NEPGA, and NESCOE. NEPOOL filed limited comments on January 19, 2016. The ISO and NRG filed protests on the January 21 comment date. Lotus answered the ISO and NRG protests on February 28 and, "because ISO-NE has stated that an order granting the Complaint would necessitate a delay in [FCA10], Lotus respectfully makes an emergency motion asking the Commission to delay the start of the auction until after it acts on the Complaint and ISO-NE has had sufficient time to implement relief." However, on February 2, Lotus withdrew that motion and its Complaint, stating that it "has been unable to secure the financing necessary to satisfy the remainder of the collateral deposit required for the Projects … to participate in … FCA 10. Lotus' inability to secure financing was caused in large part by ISO-NE's imposition of a New Resource Offer Price under its currently effective tariff and the associated business uncertainty." Lotus noted that it had separately "commenced discussions with ISO-NE concerning the need to avoid the unnecessary and harmful mitigation of truly competitive entrants in the future. Lotus intends to pursue this issue through the stakeholder process in advance of [FCA11]." If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **New DNE Dispatch Changes Effect Date (ER16-870)**

On February 2, 2016, the ISO filed changes to establish May 25, 2016 (rather than April 10, 2016) as the effective date for the new Do Not Exceed ("DNE") Dispatch Changes. The FERC accepted the DNE Dispatch Changes to become effective on April 10, 2016 in an order issued on July 23, 2015.[43] However, in its February 2 filing, the ISO reported that it would not be able to implement the DNE Dispatch Changes on that date as planned, "in part due to the need to complete thorough quality assurance testing of these changes because they affect the real-time dispatch systems." Accordingly, the ISO requested the brief delay to permit implementation on May 25, 2016. Comments, if any, on this filing are due February 23, 2016. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **CSO Termination: Spruce Mountain Wind (ER16-864)**

Pursuant to Market Rule 1 § 13.3.4(c), the ISO filed on February 2 to terminate a portion of the CSO for Resource No. 38173 held by Project Sponsor Spruce Mountain Wind. The ISO indicated that, upon FERC acceptance of the filing, the ISO will draw down the applicable amount of financial assurance provided by Spruce Mountain Wind with respect to the portion of the CSO to be terminated. NEPOOL filed a doc-less intervention on February 3. Comments on this filing are due on or before February 22. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request: FCM Qualification Lock-In Election (Calpine) (ER16-708)**

On February 4, the FERC granted Calpine's requested waiver of the FCM qualification rules to allow it to correct the New Capacity Qualification Package for one of its resources to reflect Calpine's desire to lock-in the FCA10 Capacity Clearing Price for the next six Capacity Commitment Periods (which it omitted to do in its originally submitted Qualification package documents)[44]. Comments on this waiver request were due on or before January 19, 2016. NEPOOL filed a doc-less motion to intervene. Comments supporting the filing were filed by NESCOE and Westfield Gas & Electric Light Department. PSEG filed a protest. The ISO did not intervene or comment. Unless the February 4 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).

---

[42] Lotus Complaint at pp. 12-13.

[43] *ISO New England Inc. and New England Power Pool Participants Comm.*, 152 FERC ¶ 61,065 (July 23, 2015) ("*DNE Dispatch Order*").

[44] *Calpine Energy Services, L.P.*, 154 FERC ¶ 61,082 (Feb. 4, 2016).

- **FCM Resource Retirement Reforms (ER16-551)**

As previously reported, On December 17, the ISO filed revisions it and its Internal Market Monitor ("IMM") propose to make to the FCM rules for resource retirements (the "ISO/IMM Proposal"). Specifically, the ISO/IMM Proposal requires (i) that capacity suppliers with existing resources to submit a price for the retirement of a resource (to replace the existing Non-Price Retirement Request process), (ii) the use of a Proxy De-List Bid, and (iii) notice of the potential retirement and proposed retirement price to be submitted prior to the commencement of an FCA's qualification process for new resources. The ISO/IMM Proposal was considered but not supported by the Participants Committee at its December 4, 2015 meeting. A February 16, 2016 effective date was requested. Comments on this filing were initially due on or before January 7, but following a December 18 request by NEPGA, the FERC granted a limited extension of time to submit comments to January 11. Doc-less interventions were filed by Calpine, CMEEC, ConEd, Emera, Entergy, Eversource, Exelon, MMWEC, National Grid, NEPGA, NESCOE, NextEra, NHEC, NRG, PSEG, and TransCanada. NEPOOL submitted comments on December 30 expanding on the reporting of stakeholder consideration of the ISO/IMM Proposal and amendments thereto.

Since the last Report, protests were filed by ***GEN Group*** (urging the FERC to adopt the GEN Group Proposal, while highlighting concerns with the ISO's proposed sole use of its new discounted cash flow methodology, excessive discretion, assignment of filing rights, price suppression, over-mitigation and impact on retirement rights), ***NEPGA*** (asserting that (a) elimination of the Non Price Retirement Request mechanism was not sufficiently justified, (b) proposed use of FERC-approved and proxy de-list bids will result in over-mitigation and undue discrimination, and (c) protesting the proposed assignment of filing rights), ***Dominion*** (supporting NEPGA's protest and highlighting (a) retirement decisions are significant business decisions unlikely to be used to exercise market power; (b) the concepts of "premature" or "uneconomic" retirements cannot be captured by a bright line test; and (c) de-list bid review should defer to the business judgment of the capacity supplier to match the allocation of risk in the market), ***NRG*** ((a) identifying price suppression, over-mitigation, and unduly discriminatory pricing effects of the ISO's proposal; and (b) asserting that it would be unjust and unreasonable to eliminate the ability for resource owners to reduce bids or to bind a resource to its retirement for every year after it places its retirement bid, and ***PSEG*** (urging the FERC to reject the filing for many of the same reasons identified by the other protestors and, if not rejected, to direct the ISO to address what PSEG perceives as the real problem -- the lack of flexibility in developing and submitting Static De-List Bids.). ***NESCOE*** submitted comments supporting the ISO's filing. On January 27, the ISO and Eversource answered the protests filed.

On February 1, the External Market Monitor, ***Potomac Economics*** moved to intervene out-of-time, supported the ISO/IMM Proposal, and recommended the following three changes to "address some of the concerns and make the reforms more effective in mitigating potential exercises of market power":

1. Allocation of the additional costs of procuring capacity to the retiring supplier when the resource in question was economic based on its competitive, FERC-approved proxy de-list bid.
2. Institution of a 15% threshold for the imposition of mitigation (i.e. mitigation only where the original de-list bid exceeds the ISO's competitive estimate by 15% or more), reasonably allowing for differing expectations and risk preferences of the supplier.
3. Augmenting the proposed portfolio test to include incremental revenues that may result from the higher FCA prices that derive not only from a supplier's portfolio of generation assets, but also from its other physical and financial positions.

This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **De-List Bid Information Release Change (ER16-538)**

On February 2, the FERC accepted revised Tariff sections which remove the requirement that the ISO publish de-list bid prices 15 days after a FCA ("De-List Bid Info Release Changes"). Instead, the De-List Bid Info Release Changes keep resource-specific bid and offer prices confidential even after completion of an FCA, because of the potential harm publication could have on the competitiveness of the FCM. The De-List Bid Info

Release Changes will become effective February 14, 2016, as requested.[45] Unless the February 2 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CTS Winter Reliability Program Cost Allocation Correction (ER16-462)**

On January 28, the FERC accepted revised Tariff sections to correct a mistake in the cost allocation rules for the Winter Reliability Program that went into effect on September 14, 2015 (the "Cost Allocation Correction"). As previously reported, the Cost Allocation Correction exempts all Coordinated External Transactions from the cost allocation for the Winter Reliability Program, consistent with the underlying principles that justify CTS for Coordinated External Transactions. The Cost Allocation Correction was accepted effective as of December 15, 2015, as requested. Unless the January 28 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Jump Ball Filing: Winter Reliability Program (ER15-2208)**

As previously reported, the FERC conditionally accepted, on September 11, NEPOOL's Winter Reliability Program Proposal as "just and reasonable and preferable … subject to ISO-NE submitting revised Tariff records in a compliance filing",[46] since submitted and accepted. The *Winter 2015-18 Reliability Program Order* was challenged by Entergy, which asserted that the FERC should reverse itself and adopt the ISO-NE Proposal. On November 9, the FERC issued a tolling order affording it additional time to consider the Entergy request for rehearing, which remains pending before the FERC. If you have any questions concerning this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com), or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Demand Curve Changes (ER14-1639)**

As previously reported, the FERC conditionally accepted on May 30, 2014, revisions to the FCM rules, jointly submitted by the ISO and NEPOOL, that establish a system-wide sloped demand curve ("Demand Curve Changes").[47] The Demand Curve Changes defined the shape of the system-wide sloped demand curve (with key points defined by CONE and the 0.1 days/year LOLE target), extended the period during which a Market Participant may "lock-in" the capacity price for a new resource from five to seven years, establish a limited renewables resource exemption, and eliminated, at the system-wide level, the administrative pricing rules that were necessary in certain market conditions under the vertical demand curve construct. In response to challenges, the FERC denied rehearing of the *Demand Curve Order*,[48] 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).[49] 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.[50] NextEra, NRG and PSEG then petitioned the DC Circuit Court of Appeals for review of the

---

[45] The FERC issued a Feb. 3 errata order correcting the Feb. 2 order to state that the effective date is February 14, 2016, as requested and filed.

[46] *ISO New England Inc. and New England Power Pool Participants Comm.*, 152 FERC ¶ 61,190 (Sep. 11, 2015) ("*Winter 2015-18 Reliability Program Order*") at P 44.

[47] *ISO New England Inc. and New England Power Pool Participants Comm.*, 147 FERC ¶ 61,173 (May 30, 2014) ("*Demand Curve Order*").

[48] *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).

[49] *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*").

[50] 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.

FERC's Demand Curve orders (March 30, 2015). Following submission of Petitioner and Intervenor for Petitioner briefs (October 5 and 20, 2015, respectively), the FERC, on November 20, 2015, requested that the Court remand the case back to the FERC for further proceedings (stating that "review of the opening briefs indicates that further consideration by the Commission is appropriate"). On December 1, 2015, the Court granted FERC's unopposed motion, and remanded the case back to the FERC for further proceedings. Since that remand, there have been no public developments to report. If you have any questions concerning these matters, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **RSP Timing Changes (ER16-819)**

On January 29, 2016, the ISO and NEPOOL jointly filed changes to OATT Attachment K to modify the timing of the Regional System Plan ("RSP") so that the full RSP report will be published every other year, rather than every year, but with supporting documents like the RSP project list, the annual load forecast, and other annual planning inputs, to continue to be published as they are completed ("RSP Timing Changes"). The RSP Timing Changes were supported by the Participants Committee at its January 8, 2016 meeting (Consent Agenda Item # 1). A March 29, 2016 effective date was requested. Comments on this filing are due February 19, 2016. Thus far, doc-less interventions were filed by NESCOE and National Grid. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **CTS Conforming Changes (ER15-2641)**

As previously reported, the FERC conditionally accepted the conforming changes to the ISO Tariff and the ISO-NE/NYISO Coordination Agreement, jointly filed by the ISO, NEPOOL, and PTO AC, to support the implementation of Coordinated Transaction Scheduling between New England and New York over the New York Northern AC interface ("CTS").[51] The conforming changes were accepted with an effective date on or after December 1, 2015, subject to two weeks' prior notice to be filed identifying the actual effective date. In accepting the changes, the FERC identified 3 corrections to be made to the Tariff provisions, which it directed be filed with the effective date notice. The November 9 order was not challenged and is final and unappealable.

Notice of December 15, 2015 Effective Date and Tariff Corrections. On December 1, the ISO filed notice that CTS would become effective ***December 15, 2015***, It also filed the minor corrections directed by the November 9 order. Comments on the notice and corrections were due on or before December 22; none were filed. CTS was implemented on December 15, 2015, and subject to action on the December 1 compliance filing, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-EM: Emera Maine/Covanta Maine LTSA Terminations (ER16-840)**

On January 29, Emera filed a notice of termination of two expired long-term transmission service agreements ("LTSAs") with Covanta Maine that had expired December 31, 2015 by their own terms. The Agreements were Service Agreements 69 and 70 under Schedule 21-EM. Emera requested that the terminations also become effective December 31, 2015. Comments on this filing are due on or before February 19, 2016. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[51] *ISO New England Inc., New England Power Pool Participants Comm., and the Participating Transmission Owners Admin. Comm.*, 153 FERC ¶ 61,159 (Nov. 9, 2015).

- **Schedule 21-NSTAR: Fore River LGIA Termination Notice (ER16-816)**

On January 29, Eversource filed a notice of termination of an LGIA that has since been replaced by an executed a three-party LGIA (NSTAR/ISO-NE/Calpine) as a result of Calpine's Interconnection Request to increase the Fore River Energy Center's Capacity Network Resource Interconnection Service. The Agreement was Service Agreement 68 under Schedule 21-NSTAR. Eversource requested that the terminations become effective January 20, 2016, the effective date of the new LGIA. Comments on this filing are due on or before February 19, 2016. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- ***Opinion 531-A* Local 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).

- ***Opinions 531-A/531-B* Local Refund Reports (EL11-66)**

In accordance with *Opinions 531-A and 531-B*, the following TOs filed their refund reports for their customers taking local service during the refund period (comment date on refund report noted in parentheses):

- Central Maine Power (Jan 21)
- Emera Maine (Jan 29)
- Eversource (CL&P, PSNH, WMECO) (Jan 21)
- National Grid (Jan 13)
- New Hampshire Transmission (Jan 21)
- NSTAR (Jan 21)
- United Illuminating (Jan 21); supplement (Feb 1)
- VT Transco (Feb 3)

All comments dates have passed. No comments were filed in response to any of the reports and each is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **LFTR Implementation: 29th Quarterly Status Report (ER07-476; RM06-08)**

The ISO filed the twenty-ninth of its Quarterly Status Reports regarding LFTR implementation on January 15, 2016. The ISO reported that a significant issues have arisen with the third-party clearing approach it has been pursuing. Specifically, during the process of developing contracts with the exchange and the clearing house, several new issues emerged that have yet to be resolved. The ISO reported that it is working both to resolve those issues and to develop an alternative approach to address the financial assurance issues inherent in the LFTR market that have long been identified in this matter. If the issues with the exchange and clearing house can be resolved, and it is possible to move forward with the third-party clearing design, the ISO reported that the Commodities Futures Trading Commission ("CFTC") and the FERC would need to serially approve the proposed structure. The ISO's preliminary sense was that CFTC approval might be obtained during the second half of 2016. That approval would be followed by finalization of rules through the NEPOOL process and a filing with the FER in early 2017. Assuming CFTC approval and Commission acceptance, the third-party clearing design could be put in place during the fourth quarter of 2017 for the auction that covers the 2018 annual FTR period. Monthly reconfiguration auctions under the third-party clearing design could be implemented about six months later (mid-2018). Finally, the ISO expects that the

initial auction of LFTRs under the third-party clearing design could be implemented during the fourth quarter of 2019. These status reports are not noticed for public comment and no comments have been filed.

- **IMM Quarterly Markets Reports - 2015 Fall (ZZ15-4)**

On January 29, 2016, the Internal Market Monitor ("IMM") filed with the FERC its report for the Fall 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. Please note that, beginning with this report, the periods covered by these reports have been adjusted to more closely reflect the seasons but still increment the metrics by a quarter of a year (i.e. Winter: Dec-Feb; Spring: Mar-May; Summer: Jun-Aug: and Fall: Sep-Nov). These filings are not noticed for public comment by the FERC. The IMM will present a summary of this report at the February 5 meeting (Agenda Item 4A).

IX. Membership Filings

- **February 2016 Membership Filing (ER16-836)**

On January 29, NEPOOL requested that the FERC accept (i) the membership of GBE Power Inc. (Supplier Sector); (ii) the terminations of: Glacial Energy of New England (Supplier Sector), Parkview Adventist Medical Center (End User Sector), and Vermont Marble (Supplier Sector); and (iii) the name change of: Constellation Energy Power Choice, LLC (f/k/a Constellation Energy Power Choice, Inc.). Comments on this filing are due on or before February 19.

- **Involuntary Termination of Membership: NAPP (ER16-820)**

Also on January 29, NEPOOL and the ISO requested that the FERC accept the involuntary termination of the NEPOOL and Market Participant status of North America Power Partners ("NAPP") as a result of NAPP's failure to pay when due the amounts invoiced to it by ISO-NE. A January 1, 2016 effective date was requested. Comments on this filing are due on or before February 19.

- **Involuntary Termination of Membership: Negawatt (ER16-818)**

Again on January 29, NEPOOL and the ISO requested that the FERC accept the involuntary termination of the NEPOOL and Market Participant status of Negawatt Business Solutions ("Negawatt") as a result of Negawatt's failure to pay when due the amounts invoiced to it by ISO-NE. A January 1, 2016 effective date was requested. Comments on this filing are due on or before February 19.

- **January 2016 Membership Filing (ER16-670)**

On December 30, NEPOOL requested that the FERC accept (i) the membership of Solea Energy (Supplier Sector), and Archer Energy (Supplier Sector); (ii) the terminations of: Gulf Oil (Supplier Sector), Tyngsboro Spindle and Beacon Power (AR Sector), and Hawkes Meadow Energy (Related Person of Wallingford Energy, Generation Sector); and (iii) the name change of: Uniper (f/k/a E.ON) Global Commodities North America LLC. Comments on this filing were due on or before January 20, 2016; none were filed. This matter is pending before the FERC.

- **Suspension Notices (not docketed)**

Since the last Report, the ISO filed, pursuant to Section 2.3 of the Information Policy, two notices with the FERC noting that the following Participants were suspended from the New England Markets on the dates indicated (at 8:30 a.m.) due to a Payment Default:

Date of Suspension/ FERC Notice	*Participant Name*	*Date Reinstated*
Jan 26/27	Lotus Danbury LMS100 One, LLC	Feb 4, 2016
Jan 26/27	Lotus Danbury LMS100 Two, LLC	Feb 4, 2016

Suspension notices are for the FERC's information only and are not docketed or noticed for public comment.

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*).

- **Glossary Definition Changes (RD16-3)**

On January 21, the FERC approved changes to 26 defined terms in NERC's Glossary, which contains the definitions of terms used in NERC Reliability Standards. The changes will become effective April 1, 2016, as requested. Unless the January 21 order is challenged, this proceeding will be concluded.

- **Revised Reliability Standard: BAL-002-2 (RM16-7)**

On January 29, 2016, NERC filed for approval a revised Reliability Standard -- BAL-002-2 (Disturbance Control Performance - Contingency Reserve for Recovery from a Balancing Contingency Event), and associated Glossary definitions, implementation plan, VRFs and VSLs (together, the "BAL Changes"). NERC stated that the BAL Changes consolidate six requirements in BAL-002-1 into three requirements. The 3 requirements are supported by several proposed associated NERC Glossary definitions, along with a revised Applicability section that incorporates language from the existing Standard. BAL-002-2 requires responsible entities to maintain and deploy energy reserves and to stabilize system frequency through identification of a Reportable ACE deviation and restoration of Reporting ACE to defined values after a system disturbance. BAL-002-2 will also require the responsible entity to maintain an Operating Process to ensure maintenance of Contingency Reserves to a level at least equal to the responsible entity's Most Severe Single Contingency ("MSSC"). By doing so, BAL002-2 will create and implement a continent-wide reserve policy to ensure that responsible entities will always have adequate Contingency Reserves to be deployed as necessary. NERC requested that responsible entities be required to comply with BAL-002-2 on the first day of the first calendar quarter that is six months after this standard is approved by the FERC. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- ***Order 822*: 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 January 21, the FERC issued Order 822[52] approving changes to seven CIP (Critical Infrastructure Protection) Reliability Standards designed to improve the cyber security protections required by the CIP Standards and address four directives from *Order 791* (the "Supply Chain Cyber Controls Changes"). As previously reported, 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 bulk electric system ("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.

[52] *Revised Critical Infrastructure Protection Reliability Standards*, Order No. 822, 154 FERC ¶ 61,037 (Jan. 21, 2016) ("*Order 822*").

In approving the Supply Chain Cyber Controls Changes, the FERC directed NERC to develop the following modifications to improve the revised CIP Standards: (i) modifications to address the protection of transient electronic devices used at Low Impact BES Cyber Systems; (ii) modifications to CIP-006-6 to require protections for communication network components and data communicated between all bulk electric system Control Centers according to the risk posed to the bulk electric system; and (iii) modifications to the definition for Low Impact External Routable Connectivity. *Order 822* does not address the supply chain risk management issues to be discussed at the January technical conference (the FERC will determine the appropriate action on that issue following the technical conference). *Order 822* will become effective March 31, 2016.[53]

Technical Conference on supply chain risk management issues. On January 28, 2016, the FERC held a technical conference to facilitate dialogue on supply chain risk management issues identified by the FERC in *Order 822*. Staff presented on supply chain efforts by other Federal agencies, followed by industry panels on: (1) the need for a new or modified Reliability Standard; (2) the scope and Implementation of a new or modified Standard; and (3) current supply chain risk management practices and collaborative efforts. New England panelists included: John Galloway (ISO-NE, Director, Cyber Security); and Jonathan Appelbaum (UI, Director, NERC Compliance). Speaker materials from the technical conference on posted on the FERC's eLibrary.

- **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 Assessment), associated VRFs and VSLs (together, the "GMD Operations Changes").[54] 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.[55] 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[56] and were filed by over 20 parties, including ISO-NE/NYIOS/PJM/MISO/IESO, EEI, Exelon, and NERC. On August 17, NERC filed a notice that the appeal panel appointed under NERC's process for Standards appeals had concluded NERC appeal proceedings by using a final decision finding that the objections of appellant Foundation for Resilient Societies, Inc. were afforded fair and equitable treatment during the TPL-007-1 development process. Comments on that panel's decision were due and filed by September 10. On October 2, the FERC issued a notice that comments on Foundation for Resilient Societies' filing of a September 2015 technical paper prepared by the Los Alamos National Laboratory entitled "Review of the GMD Benchmark Event in TPL-007-1" as well as on NERC's September 10 comments should be filed on or before October 22. Comments were filed by 8 parties. In addition, On November 2, D. Bardin requested official notice of National Space Weather Strategy and NSW Action Plan. On November 4, EEI, APPA, ECRC, and NRECA filed additional comments. Since the last Report, additional and reply comments were submitted by D. Bardin, U.S. Geological Survey, Southern Company, IEEE PES Transformers Committee, and Storm Analysis Consultants & Advanced Fusion Systems.

March 1, 2016 Technical Conference. On December 22 (as corrected December 23), the FERC issued a notice of a technical conference to be held on March 1, 2016. The technical conference will facilitate a structured dialogue on GMD-related topics, including but not limited to: (1) the benchmark GMD event(s); (2) vulnerability

---

[53] *Order 822* was published in the *Fed. Reg.* on Jan. 26, 2016 (Vol. 81, No. 16) pp. 4,177-4,191.

[54] *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 151 FERC ¶ 61,134 (May 14, 2015) ("*TPL-007 NOPR*").

[55] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 143 FERC ¶ 61,147 ("*Order 779*").

[56] The *TPL-007 NOPR* was published in the *Fed. Reg.* on May 26, 2015 (Vol. 80, No. 100) pp. 29,990-30,001.

assessments; and (3) monitoring of related parameters. The technical conference will be led by Commission staff, with prepared remarks to be presented by invited panelists, which must be submitted to the Commission in advance of the conference. A subsequent notice providing an agenda and details on the topics for discussion will be issued in advance of the conference. Members of the public are encouraged to attend and preregister online at: https://www.ferc.gov/whats-new/registration/03-01-16-form.asp.

- **NOPR: New Reliability Standard: PRC-026-1 (RM15-8)**

As previously reported, the FERC issued, on September 17, 2015, a NOPR proposing to approve PRC-026-1 (Relay Performance During Stable Power Swings) and associated VRFs and VSLs (the "PRC-026 Standard").[57] The PRC-026 Standard was filed in response to the FERC's directive to NERC in *Order 733*[58] 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. Comments on this NOPR were due on or before November 23, 2015[59] and were submitted by NERC, Luminant, EEI, Idaho Power, ITC, North American Generator Forum, and the Tri-State Generation and Transmission Association. This matter is 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.[60] The MOD Changes would 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[61] 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 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,[62] 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. Since the last Report, NASEB issued a report on September 25, 2015, informing the FERC that the NAESB standards development process has been completed and NAESB will file the new suite of business practice standards as part of Version 003.1 of the

---

[57] *Relay Performance During Stable Power Swings Reliability Standard*, 152 FERC ¶ 61,200 (Sep. 17, 2015).

[58] *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*").

[59] The *PRC-026 NOPR* was published in the *Fed. Reg.* on Sep. 24, 2015 (Vol. 80, No. 185) pp. 57,549-57,553.

[60] *Modeling, Data, and Analysis Reliability Standards*, 147 FERC ¶ 61,208 (June 19, 2014).

[61] 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.

[62] The MOD-001-2 NOPR was published in the *Fed. Reg.* on June 26, 2014, (Vol. 79, No. 123) pp. 36,269-36,273.

NAESB WEQ Business Practice Standards in October 2015. 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.[63] 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,[64] and were filed by NERC, EEI, ISO/RTO Council, MISO, NC Balancing Area, Northwest Power Pool Balancing Authorities, NRECA, and WECC. As noted, 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 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.

- **Rules of Procedure Changes (RR16-2)**

On January 21, 2016, the FERC approved revisions to the following parts of the NERC Rules of Procedure ("ROP"): (i) Section 317 (Periodic Review of Reliability Standards); (ii) Section 1003 (Infrastructure Security Program); (iii) Appendix 2 (Definitions Used in the Rules of Procedure); and (iv) Appendix 4D (Procedure for Requesting and Receiving Technical Feasibility Exceptions to NERC Critical Infrastructure Protection Standards). As previously reported, NERC stated that the ROP revisions were proposed to provide consistency with the version 5 CIP Reliability Standards, consistency with the Glossary of Terms (*see* RD16-3 above), and to reflect, in the body of the ROP, previously-approved revisions regarding the timing of periodic reviews of Reliability Standards. The proposed revisions will become effective April 1, 2016, as requested. Unless the January 21 order is challenged, this proceeding will be concluded.

- **Revised Regional Delegation Agreements (RR15-12)**

On November 2, the FERC conditionally accepted a revised *pro forma* and individual Regional Delegation Agreements with each of the eight Regional Entities, including NPCC (the "RDAs"), filed by NERC to be effective January 1, 2016.[65] In accepting the RDAs, the FERC required that NERC submit changes (i) to revise section 8(f) of the RDA as directed to ensure that the RDA accounts for the required NERC audits of Regional Entities in accordance with the NERC Rules of Procedure and provides NERC the flexibility to perform reviews it deems necessary on a reasonable periodicity; (ii) to revise section 8(g) as directed in order to grant the FERC full access to the non-public material resulting from these activities; (iii) to modify the RDAs so that they

---

[63] *Electric Reliability Organization Interpretation of Specific Requirements of the Disturbance Control Performance Standard*, 143 FERC ¶ 61,138 (2013) ("*BAL-002-1a Interpretation Remand NOPR*").

[64] 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.

[65] *N. Amer. Elec. Rel. Corp.*, 153 FERC ¶ 61,135 (Nov. 2, 2015).

are subject to FERC re-evaluation and re-approval following the initial term, scheduled to end on December 31, 2020; (iv) to remove the proposed automatic renewal provisions and re-insert audit provisions in section 12(b) that had been proposed to be removed; (v) to revise section 3(b) of the RDAs to include a provision requiring NERC to maintain on its public website the currently effective versions of all of the Regional Entities' bylaws and regional standard development procedures; (vi) to clarify the meaning of other "guidance that NERC may from time to time develop," and that its guidance on reporting to the FERC instances of noncompliance of Reliability Standards and their disposition must be filed with the FERC for approval before it becomes effective; and (vii) to include language in RDA section 15 stating that Section 1500 of the NERC Rules of Procedure controls when a conflict between it and the RDAs may arise. NERC submitted its compliance filing on December 18. Comments on that compliance filing are due on or before January 8, 2016; none were filed. The compliance changes are pending before the FERC

XI. Misc. - of Regional Interest

- **203 Application: ReEnergy Sterling (EC16-58)**

On December 29, 2015, ReEnergy Sterling CT Limited Partnership ("ReEnergy Sterling") requested FERC authorization for the sale of 100% of its partnership interests to Empire Tire of Edgewater 2, LLC ("Empire Tire"). Should the transaction be consummated, ReEnergy Sterling will no longer be a Related Person to ReEnergy Stratton, Dartmouth Power or TrailStone Power. Comments on this filing were due on or before January 19, 2016; none were filed. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **203 Application: Narragansett/Entergy Rhode Island State Energy (EC16-50)**

On December 11, 2015, Narragansett Electric Company ("National Grid") requested FERC authorization to acquire from Entergy Rhode Island State Energy, L.P. ("RISE") interconnection assets associated with the RISE combined cycle natural gas-fired electric generating facility located in Johnston, Rhode Island. The purchase and sale of these limited interconnection assets are provided for by a 2015 LGIA between RIA, National Grid, and ISO-NE. Comments on this filing were due on or before January 4, 2016; none were filed. This matter is pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **203 Application: Calpine/Granite Ridge (EC16-19)**

On January 28, 2016, the FERC approved the acquisition by Calpine Granite Holdings, LLC ("Calpine") of 100% of the membership interests of Granite Ridge Energy, LLC ("Granite Ridge").[66] Challenges, if any, to the January 28 order must be filed on or before February 29, 2016. Calpine and Granite Ridge must notify the FERC within 10 days of the date that the transaction has been consummated. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **203 Application: Passadumkeag Wind Park (SunEdison/ Quantum) (EC15-217)**

On November 17, 2015, the FERC authorized a transaction whereby the membership interests in the owner of Passadumkeag Wind Park will be acquired by SunEdison.[67] Quantum and SunEdison 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).

- **PURPA Complaint: Allco Renewable Energy v. CT Agencies (EL16-11 et al.)**

On January 8, 2016, the FERC issued a notice that it was declining to initiate an enforcement action under section 210(h)(2) of the Public Utility Regulatory Policies Act of 1978 ("PURPA") as requested by Allco Renewable Energy Limited ("Allco") on November 9, 2015.[68] As previously reported, Allco's request

[66] *Calpine Granite Holdings, LLC and Granite Ridge Energy, LLC*, 154 FERC ¶ 62,058 (Jan. 28, 2016).

[67] *Passadumkeag Windpark, LLC*, 153 FERC ¶ 62,110 (Nov. 17, 2015).

[68] *Allco Renewable Energy Limited et al.*, 154 FERC ¶ 61,007 (Jan. 8, 2016) ("*Allco Notice*").

was for a FERC enforcement action under PURPA against CT DEEP and CT PURA[69] to remedy "improper implementation of PURPA" (with respect to a July 2013 solicitation and a procurement under newly enacted Section 1(c) of Connecticut Public Act 15-107). The FERC's decision not to initiate an enforcement action means that Allco may themselves bring an enforcement action against CT DEEP and CT PURA in the appropriate court.[70] If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **FirstEnergy PJM DR Complaint (EL14-55)**

On January 29, 2016, in light of the Supreme Court ruling in *FERC v. EPSA* overturning the DC Circuit Court of Appeals' decision vacating *Order 745* (*see* Section XV below), FirstEnergy withdrew its May 23, 2014 Complaint. As previously reported, 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. No FERC action on this Complaint had yet been taken and with FirstEnergy's withdrawal, reporting on this proceeding has concluded. If you have any questions concerning this matter, please contact Jamie Blackburn (jblackburn@daypitney.com; 202-218-3905) or Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Cost Sharing Agreements: National Grid/NSTAR/PSNH (Greater Boston Area Transmission Solution Plan) (ER16-878, -879, -882)**

On February 3, 2016, National Grid, NSTAR and PSNH each filed an identical version of a Cost Sharing Agreement designed to set forth in writing the respective rights and obligations of National Grid and the Eversource Companies (together, the "Parties") in connection with the sharing of costs the planning, engineering, permitting and siting of facilities associated with the Greater Boston transmission projects. The Parties entered into this Agreement to document their cooperation and coordination in constructing the Greater Boston transmission projects, which are planned reliability upgrades to satisfy certain New England regional reliability transmission needs. An April 4, 2016 effective was requested. Comments on this filing are due on or before February 24, 2016. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: National Grid/Wheelabrator Saugus (ER16-760)**

On January 21, 2016, National Grid filed a non-conforming Large Generation Interconnection Agreement ("LGIA") with Wheelabrator Saugus to govern the interconnection of Wheelabrator Saugus' 36 MW generating facility located in Saugus, Massachusetts. Since the LGIA continues the existing interconnection arrangements between National Grid and Wheelabrator Saugus, without modification to the Saugus facility's capability or operating characteristics, a new three-party Interconnection Agreement (that would include the ISO) was not required. A January 1, 2016 effective was requested. Comments on this filing are due on or before February 11, 2016. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **SGIA: CMP/Hackett Mills Hydro (ER16-518)**

As previously reported, CMP filed, on December 14, a non-conforming Small Generation Interconnection Agreement ("SGIA") with Hackett Mills Hydro Associates ("Hackett Mills Hydro") to cover the interconnection between CMP and respect Hackett Mills Hydro's 500 kW hydroelectric facility located in Poland, Maine. Since the SGIA merely continues the existing interconnection arrangement between CMP

[69] Section 210(h)(2) of PURPA permits the FERC to initiate, and for QFs to petition the FERC to initiate, an enforcement action against a State regulatory authority for failure to implement the FERC's PURPA regulations. If the FERC declines to initiate an enforcement action, the petitioning QF then has the right to bring an action in the appropriate U.S. district court to enforce the PURPA regulations.

[70] *Allco Notice* at P 2.

and Hackett Mills, without modification to that facility's capability or operating characteristics, a new three-party Interconnection Agreement (that would include the ISO) was not required. A January 1, 2016 effective was requested. Comments on this filing were due on or before January 4, 2016; none were filed. Since the last Report, on January 20, CMP amended its filing, removing Effective Date as a Milestone, and supplementing the filing with a one-line diagram not previously included. Comments on the January 20 filing are due on or before February 10, 2016. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement NSTAR/NRG Canal 3 (ER16-510)**

On February 2, 2016 the FERC accepted a Design and Engineering Agreement ("D&E Agreement") between NSTAR and NRG Canal 3 Development LLC (designated as service agreement IA-NSTAR-33) that sets forth the terms and conditions under which NSTAR will undertake certain design and engineering activities on the Interconnection Facilities identified in ISO-NE studies, prior to execution of an LGIA under Schedule 22 of the ISO-NE Tariff. Eversource stated that NSTAR's costs include applicable overheads and loaders in performing design and engineering activities for NRG's 342 MW Sandwich, MA facility. The D&E Agreement was accepted for filing as of December 11, 2015, as requested. Unless the February 2 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement NSTAR/Exelon West Medway (ER16-509)**

Also on February 2, 216, the FERC accepted a D&E Agreement between NSTAR and Exelon West Medway (designated as service agreement IA-NSTAR-32) that sets forth the terms and conditions under which NSTAR will undertake certain design and engineering activities on the Interconnection Facilities identified in ISO-NE studies, prior to execution of an LGIA under Schedule 22 of the ISO-NE Tariff. Eversource stated that NSTAR's costs include applicable overheads and loaders in performing design and engineering activities for Exelon's 207 MW West Medway, MA facility. The D&E Agreement was accepted for filing as of December 11, 2015, as requested. Unless the February 2 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA – PSNH/Schiller Generating Station (ER16-391)**

On January 11, the FERC accepted a two-party LGIA between Eversource (PSNH) and Schiller Generating Station, a 180 MW, four-unit power plant, consisting of two coal-fired steam units, one wood-fired steam unit and one combustion turbine located in Portsmouth, New Hampshire. The LGIA was entered into in order to demonstrate compliance with REC Purchase Agreements and to formalize a pre-existing LGIA covering the station. PSNH is the owner and operator of Schiller Station. The LGIA was accepted effective as of January 1, 2016, as requested. Unless the January 11 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).

- **Emera MPD OATT Changes (ER15-1429; EL16-13)**

As previously reported, the FERC conditionally accepted, on December 7, 2015, changes to the Maine Public District Open Access Transmission Tariff ("MPD OATT"), including to the rates, terms, and conditions set forth in MPD OATT Attachment J.[71] However, the FERC found, ultimately, that the changes to the MPD OATT had not been shown to be just and reasonable, may be unjust and unreasonable, instituted a Section 206 proceeding (in EL16-13) to examine the provisions, and set the matter for a trial-type evidentiary hearing, to be held in abeyance pending the outcome of settlement judge procedures (*see* below). In addition, the FERC noted an inconsistency between the tariff language that Emera Maine filed in eLibrary and the electronic tariff language that Emera Maine submitted through eTariff. Emera was directed to review the entire eLibrary and eTariff Record and to submit appropriate modifications on or before January 6, 2016

[71] *Emera Maine*, 153 FERC ¶ 61,283 (Dec. 7, 2015).

to either the eTariff version or the eLibrary version of the filing, or both, to ensure consistency. Emera submitted a filing on January 4, 2016 in response to that directive.

Background. As previously reported, 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. Emera Maine stated that the changes to the MPD OATT were 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. The "Maine Customer Group"[72] 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.

Hearing and Settlement Judge Procedures. The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and will hold the hearing in abeyance pending the outcome of settlement judge procedures. As previously reported, Chief Judge Cintron designated ALJ Karen Johnson as the settlement judge for these proceedings on December 14. A first settlement conference was held January 5, 2016. In a January 12 status report, Judge Johnson reported that, at the January 5 conference, the parties agreed to exchange information and discuss settlement options. Accordingly, Judge Johnson recommended that settlement judge procedures be continued. A second settlement conference was scheduled for March 3, 2016. On January 20, Emera moved for adoption of a protective order. That order was adopted by Chief Judge Cintron on January 21.

If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **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

[72] 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").

("ITC") to NYISO and PJM",73 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).

- **FERC Enforcement Action: Order of Non-Public, Formal Investigation (IN15-10)**

MISO Zone 4 Planning Resource Auction Offers. On October 1, 2015, the FERC issued an order authorizing Enforcement to conduct a non-public, formal investigation, with subpoena authority, regarding violations of FERC's regulations, including its prohibition against electric energy market manipulation, that may have occurred in connection with, or related to, MISO's April 2015 Planning Resource Auction for the 2015/16 power year.

Unlike a staff notice of alleged violation, a FERC order converting an informal, non-public investigation to a formal, non-public investigation does not indicate that the FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation. It does, however, give OE's Director, and employees designated by the Director, the authority to administer oaths and affirmations, subpoena witnesses, compel their attendance and testimony, take evidence, compel the filing of special reports and responses to interrogatories, gather information, and require the production of any books, papers, correspondence, memoranda, contracts, agreements, or other records.

- **FERC Enforcement Action: Show Cause Order – Coaltrain, its Co-Owners & Traders/Analysts (IN16-4)**

On January 6, 2015, the FERC issued an order[74] directing Coaltrain Energy L.P. ("Coaltrain"), its co-owners Peter Jones and Shawn Sheehan, and its traders/analysts Robert Jones, Jeff Miller, Jack Wells and Adam Hughes (Collectively, "Respondents") to show cause why (i) they should not be found to have violated the FERC's Anti-Manipulation Rule by executing a scheme involving manipulative PJM Up-To Congestion trading between June and September 2010; (ii) why Coaltrain should not be found to have violated the FERC's Market Behavior Rules through false and misleading statements and material omissions relating to the existence of documents responsive to data requests and relating to the trading conduct at issue; (iii) why Coaltrain, P. Jones and Sheehan should not be jointly and severally required to disgorge unjust profits of $4,121,894; and (iv) why all Respondents should not be assessed civil penalties as follows: Coaltrain ($26 million); P. Jones and Sheehan ($5 million); R. Jones ($1 million); Miller and Wells ($500,000); and Hughes ($250,000). Following an extension request and notice by the FERC, Respondents must file an answer by March 4, 2016. In that answer, Respondents will have the option to choose between either (a) an administrative hearing before a FERC ALJ prior to the assessment of a penalty, or (b) a prompt penalty assessment by the FERC under FPA section 31(d)(3)(A). FERC Staff's reply will be due 30 days following Respondent's reply.

---

[73] *Midwest Indep. Trans. Sys. Op., Inc.*, 141 FERC ¶ 63,021 (Dec. 18, 2012) ("*MISO Initial Decision*") at P 923.

[74] *Coaltrain Energy, L.P. et al*, 154 FERC ¶ 61, 002 (Jan. 6, 2016).

- **FERC Enforcement Action: Show Cause Order - Etracom & M. Rosenberg (IN16-2)**

On December 16, 2015, the FERC issued an order[75] directing Etracom LLC ("Etracom") and its principal member and primary trader, Michael Rosenberg, to show cause why (i) it should not be found to have violated the FERC's Anti-Manipulation Rule by engaging, during May 2011, in manipulative virtual trading at CAISO's New Melones Intertie in order to artificially lower the day-ahead LMP and economically benefit ETRACOM's Congestion Revenue Rights sourced at that location; (ii) why ETRACOM should not pay a civil penalty in the amount of $2.4 million; (iii) why Rosenberg should not pay a $100,000 civil penalty; and (iv) why ETRACOM should not disgorge $315,072 plus interest in unjust profits, or a modification to these amounts as warranted. On December 31, the FERC granted Etracom an extension of time to file its response, to February 16, 2016. On January 14, pursuant to Ordering Paragraph D of the *Etracom Show Cause Order*, Etracom elected, should the FERC assess any civil penalties in this proceeding, prompt assessment of a penalty and a *de novo* review of those penalties in federal district court, (rather than an ALJ review of such penalties). FERC staff will have 30 days from the date of Etracom's yet-to-be-filed response to file a reply.

- **FERC Enforcement Action: Staff Notices of Alleged Violations (IN__-___)**

Berkshire Power Company/Powerplant Management Services. On October 23, 2015, the FERC issued a notice that Staff of the Office of Enforcement ("OE") has preliminarily determined that Berkshire Power Company and Powerplant Management Services violated the FERC's Anti-Manipulation Rule by engaging in a manipulative scheme to conceal maintenance work and associated outages beginning at least as early as January 2008 and continuing through March 2011. In addition Staff alleges that Berkshire violated FERC-approved Reliability Standards (by failing to provide outage information to its Transmission Operator and failing to inform its Transmission Operator and Host Balancing Authority of all generation resources available for use) and FERC's Market Behavior Rules (by failing to comply with various provisions of the ISO Tariff and by making false and misleading statements to the ISO regarding its maintenance work and associated outages).

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.[76] 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 Audit of ISO-NE (PA16-6)**

On November 24, 2015, the FERC informed ISO-NE that it will evaluate ISO-NE's compliance with: (1) the transmission provider obligations described in the Tariff, (2) *Order 1000* as it relates to transmission planning and expansion, and interregional coordination, (3) accounting requirements of the Uniform System of Accounts under 18 C.F.R. Part 101, (4) financial reporting requirements under 18 C.F.R. Part 141; and (5) record retention requirements under 18 C.F.R. Part 125. The FERC indicated that the audit will cover the period July 10, 2013 through the present.

XII. Misc. - Administrative & Rulemaking Proceedings

- **White Paper: Guidance Principles on Clean Power Plan Modeling (AD16-14)**

On January 20, the FERC issued a Staff White Paper that identified four guiding principles that may assist transmission planning entities, or other interested stakeholders, in conducting effective analysis of the Clean Power Plan ("CPP") and associated state plans, federal plans or multi-state plans (compliance plans). FERC stated that NERC and the regional electric reliability organizations may also benefit from following these guiding principles as they perform CPP-related analyses. The guiding principles address the following

[75] *ETRACOM LLC and Michael Rosenberg*, 153 FERC ¶ 61, 314 (Dec. 16, 2015) ("*Etracom Show Cause Order*").

[76] *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).

four areas: (1) transparency and stakeholder engagement; (2) study methodology and interactions between studies; (3) study inputs, sensitivities and probabilistic analysis; and (4) tools and techniques.

- **Price Formation in RTO/ISO Energy and Ancillary Services Markets (AD14-14)**

On November 20, 2015, the FERC directed each RTO/ISO to publicly provide information related to certain price formation issues.[77] Specifically, the FERC asked for information regarding five price formation issues: (1) pricing of fast-start resources; (2) commitments to manage multiple contingencies; (3) look-ahead modeling; (4) uplift allocation; and (5) transparency. The FERC directed each RTO/ISO to file a report that provides an update on its current practices in the identified topic areas, that provides the status of its efforts (if any) to address each of the five issues, and that fully responds to the questions on or before February 3, 2016. Following the submission of the RTOs'/ISOs' reports, the FERC will allow for public comment. The FERC also indicated it would use the reports and comments to determine what further action is appropriate. Since the last Report, the ISO/RTO Council requested, on January 15, an extension of time so that responses are due instead on March 4, 2016. The FERC granted that request on January 27, so that the ISO/RTO responses are now due on or before March 4, 2016, and public comments 30 days thereafter, or April 4, 2016.

- **NOPR: Price Formation Fixes - Price Caps in RTO/ISO Markets (RM16-5)**

On January 21, the FERC issued a NOPR proposing to require that each RTO/ISO cap each resource's incremental energy offer to the higher of $1,000/MWh or that resource's verified cost-based incremental energy offer (regardless of fuel-type).[78] Verified cost-based incremental energy offers above $1,000/MWh would be used for purposes of calculating Locational Marginal Prices (LMPs). Comments on the *Price Cap NOPR* are due on or before April 4, 2016.[79]

- **NOPR: Reactive Power Requirements for Wind Generators (RM16-1)**

On November 19, the FERC issued a NOPR proposing to eliminate the exemptions for wind generators from the requirement to provide reactive power.[80] As a result, all newly interconnecting generators, and all existing non-synchronous generators making upgrades to their generation facilities that require new interconnection requests, would be required to provide reactive power. To implement this requirement, the FERC proposes to revise the *pro forma* LGIA, Appendix G to the *pro forma* LGIA, and the *pro forma* SGIA. Comments on the *Reactive Power NOPR* were due on or before January 25, 2016[81] and were filed by more than 20 parties, including NEPOOL, ISO-NE, ISO/RTO Council, AWEA, EEI, NERC, NextEra, and UCS. In its initial comments, NEPOOL provided a status report both on NEPOOL's consideration of the *Reactive Power NOPR* and on NEPOOL's own consideration with the ISO of the reactive power requirement for non-synchronous (i.e., primarily wind) generators, that has been ongoing in New England for several months, independent of the *Reactive Power NOPR*. NEPOOL indicated that it would supplement its initial comments with substantive comments following the February 5 Participants Committee meeting (at which the comments are to be considered under Agenda Item 6).

- **NOPR: Price Formation Fixes - Settlement Intervals/Shortage Pricing (RM15-24)**

On September 17, the FERC issued a NOPR proposing to revise its regulations to require that each RTO/ISO (i) settle (a) energy transactions in its real-time markets at the same time interval it dispatches energy

---

[77] *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, 153 FERC ¶ 61,221 (Nov. 20, 2015).

[78] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 154 FERC ¶ 61,038 (Jan. 21, 2016) ("*Price Cap NOPR*").

[79] The *Price Cap NOPR* was published in the *Fed. Reg.* on Feb. 4, 2016 (Vol. 81, No. 23) pp. 5,951-5,965.

[80] *Reactive Power Requirements for Non-Synchronous Generation*, 153 FERC ¶ 61,175 (Nov. 19, 2015) ("*Reactive Power NOPR*").

[81] The *Reactive Power Requirements for Non-Synchronous Generation NOPR* was published in the *Fed. Reg.* on Nov. 25, 2015 (Vol. 80, No. 227) pp. 73,683-73,689.

and (b) operating reserves transactions in its real-time markets at the same time interval it prices operating reserves; and (ii) trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs.[82] The FERC sated that adopting these reforms would align prices with resource dispatch instructions and operating needs, providing appropriate incentives for resource performance. The *Settlement Intervals/Shortage Pricing NOPR* was discussed at the October 7-9 Markets Committee meeting. Comments on this NOPR were due on or before November 30, 2015.[83] Nearly 50 sets of comments were filed, including comments by NEPOOL (summarizing the status of New England's consideration of pricing reforms like those identified in the NOPR and urging that FERC action on the NOPR, and any final rule, be sufficiently flexible in implementation schedule and details to permit final approval and implementation of New England's solutions, which are planned to be filed in the first half of 2016 and implemented in 2017), ISO-NE, Potomac Economics (ISO-NE EMM), APPA/NRECA, EEI, EPSA, Direct Energy, Dominion, Entergy, ESA, Exelon, IRC, NEI, Public Interest Organizations, and PSEG. Since the last Report, Golden Spread Electric Cooperative submitted limited reply comments. This matter is pending before the FERC.

- **NOPR: Connected Entity Data Collection (RM15-23)**

As previously reported and summarized, the FERC issued a NOPR that would dramatically expand the corporate and relationship structure information that all Market Participants will be required to share with the ISO as a condition to their participation and that the ISO would be required to share with the FERC.[84] The FERC proposed to require that all ISO/RTO market participants report all of the their "Connected Entities," which is a newly defined term that is much broader than, and is intended to replace, "Affiliate" as defined in and administered under the ISO Tariff. The rule would multiply by several factors the amount of information required to be reported, by including reporting of certain employee and contractual relationships, and of debt/profitability arrangements. The NOPR proposed additional registration and compliance requirements for each market participant and RTO/ISO. The FERC explained in the NOPR that this additional data collection will improve the information that it has for detecting market manipulation, which is a FERC enforcement priority. A more detailed summary of the *Connected Entity Data Collection NOPR* was distributed with the additional materials for the October 2 meeting.

Dec 8 Technical Conference. A staff-led and Commissioner (LaFleur and Norris)-attended technical conference was held on for December 8. The technical conference was intended to allow for a dialogue regarding industry concerns and the extent of the burdens that would be imposed upon market participants under the NOPR. It also provided staff an opportunity to ask questions and clarify a number of issues, many raised in NEPOOL's comments filed on December 1 (highlighted at the technical conference as "particularly constructive" and an example of how others might use the comment period to offer "specific, concrete suggestions").

Staff clarifications included the following:

- The Proposed Rule is designed to address and give some visibility to the unknown and "hidden" relationships, and the incentives that may be associated with those relationships, that present a risk to the efficiency and fairness of the wholesale markets.
- The Proposed Rule applies only to participants in RTO/ISO markets. Participants in wholesale gas markets who are not RTO/ISO market participants have no obligation under the Proposed Rule.

---

[82] *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 152 FERC ¶ 61,218 (Sep. 17, 2015) ("*Settlement Intervals/Shortage Pricing NOPR*").

[83] The *Settlement Intervals/Shortage Pricing NOPR* was published in the *Fed. Reg.* on Sep. 29, 2015 (Vol. 80, No. 188) pp. 58,393-58,405.

[84] *Collection of Connected Entity Data from Regional Transmission Organizations and Independent System Operators*, 152 FERC ¶ 61,219 (Sep. 17, 2015) ("*Connected Entity Data Collection NOPR*").

- The unique Legal Entity Identifier (LEI) will only be required of market participants, not all Connected Entities.
- "FERC jurisdictional markets" means participation in any or all of an RTO/ISO's markets, physical and financial. Natural gas resources not included.
- Trader. Similar to the NEPOOL-proposed definition, a trader is the person who makes the decisions, or devises the strategies, for buying and selling physical or financial products which are or may be traded in the RTO/ISO electric markets. It would not include a person who simply "pushes the button" to make a trade, if that person has no control over or input into the decision-making process.
- With respect to Contracts, Control, whether over trading activities or unit commitment decisions, is the defining characteristic that creates a connected entity relationship. Fuel arrangements, physical maintenance arrangements, and standard power purchase agreements, and other contracts not conferring control, would not be included.

Staff's presentations, as well as presentations and written comments from some of the speakers, are available in the FERC's eLibrary and attached for your convenience. For those who were unable to attend or view the technical conference via webcast, an archive of the webcast will be available for three months at http://stream.capitolconnection.org/capcon/ferc/ferc.htm.

Comments on the NOPR were due on or before January 22, 2016. The FERC denied a December 30 request by Industry Groups[85] that it suspend the January 22 comment date and either: (1) withdraw the NOPR and issue a new or revised NOPR; or (2) issue a supplemental NOPR that takes into consideration the discussion and clarifications discussed at the December 8, 2015 Technical Conference.[86] Over 50 parties, including the ISO-NE IMM, ISO-NE/MISO, IRC, Backyard Farms, CMEEC/MMWEC/NHEC/VPPSA, Dominion, National Grid, NextEra, NRG, and SunEdison, submitted comments. This matter is pending before the FERC.

- **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 stated 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 were due on or before September 8, 2015. More than 30 sets of comments were filed, including by ISO-NE, NESCOE, ISO/RTO Council ("IRC"), APPA/NRECA/Large Public Power Council, EEI, EPSA, NextEra, NRG, and PSEG. Reply comments were filed by AWEA and SunEdison. This matter is pending before the FERC.

[85] "Industry Groups" are American Forest & Paper Association ("AF&PA"), Canadian Electricity Association ("CEA"), Commercial Energy Working Group ("CEWG"), Edison Electric Institute ("EEI"), Electricity Consumers Resource Council ("ELCON"), Electric Power Supply Association ("EPSA"), Independent Power Producers of New York, Inc.("IPPNY"), Industrial Energy Consumers Group ("IECG"), International Energy Credit Association ("IECA"), and the Retail Energy Supply Association ("RESA"). The Industry Groups' request was supported by Ares EIF and the National Rural Electric Cooperative Association ("NRECA") and American Public Power Association ("APPA").

[86] *Collection of Connected Entity Data from Regional Transmission Organizations and Independent System Operators*, 154 FERC ¶ 61,016 (2016).

- ***Order 816*: MBR Authorization Refinements (RM14-14)**

As previously reported, the FERC issued *Order 816* on October 16, 2015.[87] *Order 816* represents another step in the FERC's efforts to modify, clarify and streamline certain aspects of its market-based rate ("MBR") program. The *Order 816* revisions are intended to both increase transparency and refine existing filing requirements. By way of example, *Order 816:*

- requires electronic submissions of asset appendices in MBR filings to be searchable and sortable, and eliminates the requirement to report behind-the-meter generation in asset appendices
- requires MBR sellers to report all long-term firm purchases of capacity and energy that have associated long-term firm transmission (thereby providing a more accurate measure of a seller's generation resources)
- eliminates MBR sellers' requirement to file quarterly land acquisition information for new generation sites
- reduces the number of "notice of change in status" filings by establishing a new threshold for reporting new affiliations and redefines the default relevant geographic market for an independent power producer with generation capacity located in a generation-only balancing authority area
- provides clarification on issues including capacity ratings and simultaneous transmission import limit (SIL) studies

Order 816 became effective January 28, 2016.[88] Requests for clarification and/or rehearing of *Order 816* were filed by EDF Renewables, EEI, EPSA, Invenergy, NextEra, Southern Company, TAPS, SoCal Edison, and the National Hydropower Association. On December 11, 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. On December 23, the FERC partially granted an extension of time such that market-based rate applicants and sellers will not be required to comply with the corporate organizational chart requirement prior to the issuance of an order on the merits of the requests for rehearing of the corporate organizational chart requirement.

XIII. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Jamie Blackburn (202-218-3905; jblackburn@daypitney.com).

- **Section 5 Investigations: Columbia (RP16-302); Empire (RP16-300); Iroquois (RP16-301); Tuscarora (RP16-299)**

On January 21, the FERC issued orders initiating Natural Gas Act Section 5 investigations into whether the rates charged by the following gas pipeline companies were too high above their costs under federal law:

- Columbia Gulf Transmission, LLC (Docket No. RP16-302);[89]
- Empire Pipeline, Inc. (Docket No. RP16-300);[90]
- Iroquois Gas Transmission System, LP (Docket No. RP16-301);[91] and
- Tuscarora Gas Transmission Company (Docket No. RP16-299);[92]

---

[87] *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Srvcs. by Public Utils.*, 153 FERC ¶ 61,065 (Oct. 16, 2015) ("*Order 816*").

[88] *Order 816* was published in the *Fed. Reg.* on Oct. 30, 2015 (Vol. 80, No. 210) pp. 67,056-67,123.

[89] *Columbia Gas Transmission, LLC*, 154 FERC ¶ 61,027 (2016).

[90] *Empire Pipeline, Inc.*, 154 FERC ¶ 61,029 (Jan. 21, 2016).

[91] *Iroquois Gas Transmission System, LP*, 154 FERC ¶ 61,028 (Jan. 21, 2016).

[92] *Tuscarora Gas Transmission Company*, 154 FERC ¶ 61,030 (Jan. 21, 2016).

Acting Chief Administrative Law Judge Carmen Cintron subsequently designated the following Administrative Law Judges to preside over the Track II hearings in the respective proceedings and orders, where applicable, scheduling pre-hearing conferences, and establishing dates for the commencement of hearings and initial decisions have been identified, as follows:

Case	Presiding Judge	Prehearing Conf	Hearings Commence	Initial Decision
Columbia Gas (RP16-302)	John P. Dring	TBD	TBD	TBD
Empire Pipeline (RP16-300)	Michael J. Cianci, Jr.	TBD	TBD	TBD
Iroquois Gas (RP16-301)	David H. Coffman	Feb 10, 2016	TDB	TBD
Tuscarora Gas (RP16-299)	Dawn E.B. Scholz.	Feb 11, 2016	Nov 15, 2016	Feb 28, 2017

Since the issuance of the orders, numerous parties have moved to intervene in each of the proceedings.

- ***Order 820*: Delegation of Authority for FERC Form No. 552 (RM16-4)**

On December 22, 2015 the Commission gave the Office of Enforcement express authority over FERC Form No. 552.[93] Form 552 collects information about transactions among participants in the natural gas market and was created in 2007 as part of *Order 704*. *Order 820* enhances consistency and clarity by adding Form 552 to the list of forms included in the delegations to the Office of Enforcement.

- ***Order 809*: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities (RM14-2)**

On April 16, 2015, the FERC issued *Order 809*,[94] which changed the nationwide Timely Nomination Cycle deadline for scheduling natural gas transportation from 11:30 a.m. Central Clock Time (CCT) to 1:00 p.m. CCT, and revised the intraday nomination timeline to add an additional intraday scheduling opportunity during the gas operating day (Gas Day). *Order 809* also modified the scheduling practices used by interstate pipelines to schedule natural gas transportation service, and provided additional contracting flexibility to firm natural gas transportation customers through the use of multi-party transportation contracts. *Order 809* DID NOT change the start time of the nationwide Gas Day (which remains 9:00 a.m. CCT), as had been proposed in the underlying NOPR.[95] *Order 809* established an implementation date of April 1, 2016.[96] In response to *Order 809*, ISO-NE described, and the FERC accepted ISO-NE's explanation, why changes to the time at which the results of the ISO-NE Day-Ahead Energy Market and RAA process are posted were not necessary in response to the FERC's rulemaking.

Requests for rehearing and/or clarification of *Order 809* were filed by Desert Southwest Pipeline Stakeholders and the American Gas Association. On May 19, 2015, 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 September 17, 2015, the FERC issued an Order on Rehearing denying a request from a group of utilities and state regulators from Southwest states for rehearing of *Order No. 809*.[97] The Commission recognized the time commitments in implementing the revised nomination timeline, and requested that the natural gas and electric industries, through

[93] *Delegation of Authority for FERC Form No. 552*, Order No. 820, 153 FERC ¶ 61,335 (Dec. 22, 2015) ("*Order 820*").

[94] *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*").

[95] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 146 FERC ¶ 61,201 (Mar. 20, 2014).

[96] *Order 809* was published in the *Fed. Reg.* on Apr. 24, 2015 (Vol. 80, No. 79) pp. 23,198-23,227.

[97] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, Order No. 809, 152 FERC ¶ 61,049 (Apr. 24, 2015), *order on reh'g*, 152 FERC ¶ 61,212 (Sept. 17, 2015).

NAESB, begin considering the development of standards related to faster, computerized scheduling and file such standards or a report on the development of such standards with the Commission by October 17, 2016.

On May 28, 2015, the American Gas Association, the American Public Gas Association, and the Interstate Natural Gas Association of America (collectively, the Associations) filed a request for the Commission to clarify the manner in which all pipelines should implement the standards on April 1, 2016, as well as requested 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.[98] The FERC indicated that it recognized the value in establishing a default interpretation of capacity release contractual recall provisions to assist parties in navigating the transition between the two intraday and three intraday nomination schedules. 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.

In response to comments received in response to its July 31 Order, the FERC issued an order on October 15, 2015[99] in which it provided default interpretations to apply to the intraday recall rights associated with capacity release transactions that spanned the implementation date of April 1, 2016. The interpretations are intended to assist parties to capacity release transactions straddling April 1, 2016 in agreeing in advance to contractual recall rights, as such rights are necessarily affected by whether there are three or two intraday nomination schedules. Moreover, the FERC also directed releasing shippers to notify the applicable interstate pipeline and the replacement shippers by November 13, 2015 if the parties do not agree on alternative recall rights, and to specify what the releasing shipper believes should be the alternative recall rights.

- **Rice Energy Marketing, Order on Petition for Declaratory Order (RP15-1089)**

On October 15, 2015, the FERC issued a Declaratory Order in response to a petition filed by Rice Energy, a producer, clarifying the extent to which releases of natural gas pipeline capacity to asset managers are exempt from FERC's prohibition on buy/sell transactions. The FERC explained that the exemption applies to volumes of gas purchased from a releasing shipper in a "supply asset management agreement" (supply AMA) as well as a "delivery AMA," thereby clarifying that the two types of AMAs are equivalent exemptions from the prohibition on buy/sell transactions.

Under the FERC's regulations, shippers must conduct capacity release transactions through the pipeline consistent with FERC-prescribed posting and bidding requirements. To ensure that capacity holders and persons wishing to acquire capacity did not circumvent those requirements, the FERC established several safeguards, including the requirement that a shipper must have title to the gas transported in the shipper's capacity. Another safeguard is the prohibition on buy/sell transactions whereby a shipper, e.g., a local distribution company or "LDC," purchases gas in the production area from an end-user and uses its capacity to transport the gas and sell the gas to the end-user at the delivery point on its system.

However, in Order No. 712, the FERC exempted AMAs from the competitive bidding requirements of FERC's regulations, the prohibition against tying a release to an extraneous condition, and, at least to some degree, the prohibition on buy/sell transactions. An AMA is a contractual relationship by which a party, an asset manager, agrees to manage gas supply, delivery arrangements, and storage as well as transportation, for another

---

[98] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 152 FERC ¶ 61,095 (July 31, 2015).

[99] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, 153 FERC ¶ 61,049 (Oct. 15, 2015), "Order Establishing Default Interpretations for Capacity Release Contracts".

party. Under an AMA, a holder of firm transportation capacity releases a portion or all of its capacity to the asset manager. The capacity holder may also assign gas production and sales contracts to the asset manager.

The Declaratory Order effectively allows a releasing shipper in a supply AMA to use an asset manager solely to manage the releasing shippers' capacity, while continuing to market its own gas. By entering into a buy/sell transaction, producers and marketers can market their own gas and avail themselves of the benefits of an AMA without revealing sensitive competitive information to a competing marketer acting as an asset manager.

- **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.[100] 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.[101] 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 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.[102] 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.

- ***Opinion No. 538*: ANR Storage Company, Order on Initial Decision (RP12-479)**

In what it described as "the first fully-litigated proceeding where a gas storage provider has sought market-based rate authority," the FERC, on October 15, 2015, upheld a January 2014 Initial Decision in which a FERC Presiding Judge (ALJ) denied an application for market-based rate authorization by a natural gas storage provider that previously charged cost-based rates for its services. As the first case of its kind, the FERC provided clarity to its policies and procedures for market-based rate applications from gas storage providers, and also described how gas storage providers can meet the evidentiary burden to demonstrate that they lack significant market power. While reversing the ALJ on certain discrete issues (such as the Initial Decision's finding that market-based rate applicants are required to meet their evidentiary burden solely through direct testimony), the FERC ultimately agreed with the ALJ that the applicant (ANR Storage) "has not met its evidentiary burden to show it lacks significant market power in the relevant markets."[103] Requests for rehearing of *ANR Order* were filed by ANR and the Joint Intervenor Group.[104] On December 11, 2015, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending before the FERC..

---

[100] *Posting of Offers to Purchase Capacity*, 146 FERC ¶ 61,203 (Mar. 20, 2014).

[101] *Id.* at P 6.

[102] *See BR Pipeline Co. et al.*, 149 FERC ¶ 61,031 (Oct. 16, 2014).

[103] *ANR Storage Co.*, 153 FERC ¶ 61,052 (Oct. 15, 2015) ("*ANR Order*"), *reh'g requested*.

[104] "Joint Intervenor Group" is comprised of the following: the Canadian Association of Petroleum Producers ("CAPP"), Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin (jointly, "NSP"), Tenaska Gas Storage, LLC ("Tenaska"), and BP Canada Energy Marketing Corp., ("BP Canada").

- **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.

BP (IN13-15). On August 13, Judge Cintron issued her Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the Commission's regulations and section 4A of the Natural Gas Act.[105] Specifically, after extensive discovery and hearing procedures, Judge Cintron found that BP's Texas team engaged in market manipulation by changing their trading patterns, between September 18, 2008 through the end of November 2008, in order to suppress next-day natural gas prices at the Houston Ship Channel ("HSC") trading point in order to benefit correspondingly long position at the Henry Hub trading point. Judge Cintron's Initial Decision found that:

- There were at least 48 violations on 49 days;
- BP's manipulation resulted in financial losses of $1,375,482 to $1,927,728 on the next-day natural gas markets at Houston Ship Channel (HSC) and Katy during the Investigative Period;
- the violation was less than five years after a prior FERC adjudication and adjudications of similar misconduct by the CFTC and DOJ (warranting a 2 point increase in BP's culpability score);
- BP's conduct contravened the terms of a permanent injunction with the CFTC (warranting a 2 point increase in BP's culpability score);
- BP did not have an effective Compliance program; and
- the BP Texas team's gross profits from the manipulation were between $233,330 and $316,170 and net profits between $165,749 and $248,589.

Judge Cintron also certified the *BP Initial Decision* and the record to the Commission on August 13, 2015. BP filed its Brief on Exceptions on September 14, 2015, and Enforcement Staff filed its Brief Opposing Exceptions on October 5, 2015. This matter is currently pending before the FERC.

- **FERC Enforcement Action: Staff Notices of Alleged Violations (IN__-___)**

Total Gas & Power, North America, Inc. On September 21, 2015, the FERC issued a notice that Staff has preliminarily determined that Total Gas & Power, North America, Inc. ("TGPNA") and its West Desk traders and supervisors Therese Nguyen and Aaron Hall, violated section 4A of the Natural Gas Act and the Commission's Anti-Manipulation Rule, by devising and executing a scheme to manipulate the price of natural gas in the southwest United States between June 2009 and June 2012. Specifically, Staff alleges that the scheme involved making largely uneconomic trades for physical natural gas during bidweek designed to move indexed market prices in a way that benefited the company's related positions. Staff alleges that the West Desk implemented the bidweek scheme on at least 38 occasions during the period of interest and that Therese Nguyen and Aaron Hall each implemented the scheme and supervised and directed other traders in implementing the scheme.

- **New England Pipeline Proceedings**

The following New England pipeline projects are currently before the FERC:

- ***Algonquin Incremental Market Project (AIM Project) (CP14-96)***
  - Algonquin Gas Transmission filed for Section 7(b) and 7(c) certificate Feb. 28, 2014
  - 342,000 dekatherms/day (Dth/d) 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.

[105] *BP America Inc., et al.*, 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*").

  - 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 Staff-prepared Environmental Impact Statement (EIS) issued Jan. 23, 2015.
  - Certificate of public convenience and necessity granted Mar. 3, 2015.[106]
  - Construction began May 2015.
  - In-service: Nov. 2016 (anticipated).

- ***Atlantic Bridge Project (CP16-9)***
  - Algonquin Gas Transmission filed for Section 7(b) and 7(c) certificate on Oct. 22, 2015.
  - 132,700 Dth/d of firm transportation to new and existing delivery points on the Algonquin system and 106,276 Dth/d of firm transportation service from Beverly, MA to various existing delivery points on the Maritimes & Northeast system.
  - 6.3 miles of replacement pipeline along Algonquin in NY and CT; new 7,700-horsepower compressor station in Weymouth, MA; more horsepower at existing compressor stations in CT and NY.
  - Seven firm shippers: Heritage Gas Limited, Maine Natural Gas Company, NSTAR Gas Company d/b/a Eversource Energy, Exelon Generation Company, LLC (as assignee and asset manager of Summit Natural Gas of Maine), Irving Oil Terminal Operations, Inc., New England NG Supply Limited, and Norwich Public Utilities.

- ***Connecticut Expansion Project (CP14-529)***
  - Tennessee Gas Pipeline filed for Section 7(c) certificate July 31, 2014.
  - 72,100 Dth/d of firm capacity.
  - 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.
  - Notice of Schedule issued Sept. 1 with FERC EA to be issued Oct. 23 and 90-day Federal Authorization Decision Deadline set at Jan. 21, 2016.
  - FERC Staff-prepared Environmental Assessment (EA) issued on Oct. 23, 2015, as well as contemporaneous notice soliciting comments on or before November 23, 2015.
  - Construction expected to begin Winter/Spring 2016.
  - In-service: Nov 2016 (anticipated).

- ***Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)***
  - Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
  - 650,000 Dth/d 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 of public convenience and necessity granted Dec 2, 2014;
  - Construction expected to begin first quarter 2016 (after final Federal Authorizations).

[106] Order Issuing Certificate and Approving Abandonment, *Algonquin Gas Transmission LLC*, 150 FERC ¶ 61,163 (Mar. 3, 2015), *reh'g requested*.

- ***Salem Lateral Project (CP14-522)***
  - Algonquin Gas Transmission filed application Jul 10, 2013.
  - 115,000 Dth/d 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 Staff-prepared EA issued Dec 2, 2014.
  - Certificate of public convenience and necessity granted May 14, 2015.[107]
  - Construction began in May 2015.
  - In-Service: first quarter 2016 (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).

- **NEPGA Peak Energy Rent (PER) Complaint (16-1024**)**
  Underlying FERC Proceedings: EL15-25[108]
  Appellants: NEPGA

On January 19, 2016, NEPGA filed a petition for review of the FERC's orders on NEPGA's PER Complaint. A Docketing Statement Form, Statement of Issues to be Raised, Petitioners' and Respondents' Appearances, and procedural motions are due February 24, 2016; dispositive motions, March 10.

- **FCM Jump Ball and Compliance Proceedings (16-1023**)**
  Underlying FERC Proceedings: ER14-1050;[109] **EL14-52**[110]
  Appellants: NEPGA

Also on January 19, 2016, NEPGA filed a petition for review of the FERC's orders on the FCM PI Jump Ball Filing and the subsequent compliance proceedings. A Docketing Statement Form, Statement of Issues to be Raised, and Appearances are due February 18, 2016.

---

[107] Order Issuing Certificate, *Algonquin Gas Transmission LLC*, 151 FERC ¶ 61,118 (May 14, 2015).

[108] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

[109] 153 FERC ¶ 61,224 (Nov. 19, 2015); 153 FERC ¶ 61,223 (Nov. 19, 2015); 147 FERC ¶ 61,172 (May 30, 2014).

[110] 153 FERC ¶ 61,222 (Nov. 19, 2015); 150 FERC ¶ 61,053 (Jan. 30, 2015).

- **Base ROE Complaints (2012 and 2014) (15-1212)**
  Underlying FERC Proceedings: EL13-33; EL14-86[111]
  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 was deferred until further order of the court. However, on August 14, 2015, NETOs filed an unopposed motion to hold this case in abeyance pending final FERC action on the 2012 and 2014 ROE Complaints (*see* Section I above). On August 20, 2015, the Court granted NETOs' motion to hold the case in abeyance, subject to submission of status reports every 90 days. On November 18, the parties filed their first 90-day status report, indicating, ultimately, that the proceedings upon which the NETOs based their request for abeyance of this appeal remain ongoing.

- **Order 1000 Compliance Filings (15-1139, 15-1141**) (consolidated)**
  Underlying FERC Proceedings: ER13-193; ER13-196[112]
  Appellants: New England Transmission Owners (NETOs); NESCOE/CT DEEP/CT PURA, *et al*.

On May 15, 2015, NETOs[113] 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 November 6, 2015, the court issued an order setting the following briefing schedule (remaining dates only): Mar. 11, 2016 - Brief for Respondent; Apr. 1, 2016 - Brief for Intervenors Supporting Respondent in No. 15-1139 and Brief for Intervenors Supporting Respondent in No. 15-1141; Apr. 22, 2016 - Joint Reply Brief in No. 15-1139 and Joint Reply Brief in No. 15-1141; May 13, 2016 - Deferred Appendix; May 20, 2016 - Final Briefs. The Court noted that parties would be notified separately of the oral argument date and composition of the merits panel. Since the last Report, Joint Petitioner Briefs were filed on January 11, 2016.

- **Base ROE Complaint (2011) (15-1118, 15-1119, 15-1121**) (consolidated)**
  Underlying FERC Proceedings: EL11-66[114]
  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,[115] 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 August 10, Petitioners filed an unopposed proposed briefing format and schedule. On October 6, 2015, the court issued an order setting the following briefing schedule (remaining dates only): February 12, 2016 – FERC's brief; March 4 - Joint Intervenor Brief for Complainant, EMCOS, and Non-New England Intervenors on the issues of the ROE being too low and modification of incentive adders and Joint Intervenor Brief for NETOs on the issue of the ROE being too high; March 25 - Reply Brief(s) for Complainants/EMCOS and Joint Reply Brief for NETOs; April 15 - Deferred Appendix; April 26, 2016 - Final Briefs.

---

[111] 147 FERC ¶ 61,235 (June 19, 2014); 149 FERC ¶ 61,156 (Nov. 24, 2014); 151 FERC ¶ 61,125 (May 14, 2015).

[112] 150 FERC ¶ 61,209 (Mar. 19, 2015); 143 FERC ¶ 61,150 (May 17, 2013).

[113] "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.

[114] 150 FERC ¶ 61,165 (Mar. 3, 2015); 149 FERC ¶ 61,032 (Oct. 16, 2014); 147 FERC ¶ 61,234 (June 19, 2014).

[115] "EMCOS" are Taunton, Reading, Hingham, and Braintree.

Since the last Report, on December 7, 2015, (i) "Customers"[116] and the TOs[117]filed their Opening briefs. On December 8, the clerk's office sent to counsel a letter noting the use of uncommon acronyms and abbreviations in briefs filed with the court (parties are expected to limit the use of acronyms and to avoid using acronyms that are not widely known), advising counsel that they could submit within a week revised briefs eliminating any uncommon acronyms used in previously filed briefs, which the TOs did on December 15. The FERC's brief is next up, due to be filed, as noted above, on February 12.

- **FCM Administrative Pricing Rules Complaint (15-1071**)**
  Underlying FERC Proceedings: EL14-7[118]
  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, and did, file an abeyance status report on or before August 20, 2015. In its August 20 report, NEPGA indicated that the FERC had not taken final action in EL15-23 and requested the Court continue to hold the case in abeyance. NEPGA filed a second abeyance status report on November 18, again requesting that the Court continue to hold this case in abeyance. With the FERC's January 7, 2016 order denying rehearing of its order in EL15-23 (*see* Section I above), motions to govern future proceedings will be due February 8, 2016.

- **FCA8 Results (14-1244, 14-1246 (consolidated))**
  Underlying FERC Proceedings: ER14-1409[119]
  Appellants: Public Citizen and CT AG

As previously reported, 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. Briefing on the issue of the Court's jurisdiction to hear this matter (with FERC (supported by EPSA and NEPGA) asserting the FCA8 Results Filing Order was not an "order" within the meaning of section 313 of the FPA, or "agency action" reviewable under the Administrative Procedures Act, and Connecticut[120] and Public Citizen taking the opposing view) has now been completed. Since the last Report, the parties filed a Joint Appendix (reflecting all filings and issuances in ER14-1409) on December 16. Final Petitioner briefs and reply briefs were filed by Public Citizen on December 17; by Connecticut, on December 22. The FERC's final brief was filed on December 23, as was the final brief of Joint Intervenors for Respondent (EPSA, GenOn Energy Management, HQUS, NRG, and NEPGA). With the jurisdictional issue now fully briefed, the Court will next issue a separate order notifying the parties of the date and time of oral argument. As of the date of this Report, that order (date for oral argument) has not been set.

---

[116] "Customers" are: the Commonwealth of Massachusetts, CT AG, CT PURA, NH PUC, RI PUC, CT OCC, MOPA, NH OCA, the "EMCOS" group (Braintree, Hingham, Reading, Taunton), MMWEC, NHEC, AIM, IECG, and Power Options.

[117] In this case, TOs are CMP, Emera Maine, Eversource, National Grid, NHT, UI, and Vermont Transco.

[118] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[119] 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).

[120] For purposes of this proceeding, "Connecticut" means the CT AG, CT PURA and CT OCC.

- ***2013/14* Winter *Reliability Program* (14-1104, 14-1105, 14-1103 (consolidated))**
  Underlying FERC Proceedings: ER13-1851[121] and ER13-2266[122]
  Appellants: TransCanada and RESA

On December 22, 2015, the DC Circuit remanded the FERC's decision in ER13-2266, agreeing with TransCanada that the record upon which the FERC relied is devoid of any evidence regarding how much of the 2013/14 Winter Reliability Program cost was attributable to profit and risk mark-up (without which the FERC could not properly assess whether the Program's rates were just and reasonable).[123] The FERC must either offer a reasoned justification for the order in ER13-2266 or revise its disposition to ensure that the Program rates are just and reasonable. With respect to TransCanada's claims regarding the FERC's decision in ER13-1851, the Court found that TransCanada's challenge with respect to the procurement process, bid results, and explanation of costs were properly raised and considered in conjunction with Docket ER13-2266 and were not ripe for review in ER13-1851, and found no merit in TransCanada's challenge to the FERC's order that Program costs should be allocated to Real-Time Load Obligation. The Clerk will withhold issuance of the mandate (official remand to the FERC) until seven days after disposition of any timely petition for rehearing or petition for rehearing *en banc*.

- **New England's Order *745* Compliance Filing (12-1306)**
  Underlying FERC Proceedings: ER11-4336[124]
  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.

Status of New England Implementation of Order 745 (in light of *FERC v. EPSA* below). Recall that, in response to the FERC's issuance of *Order 745* on March 15, 2011,[125] ISO-NE submitted New England's compliance filing on August 19, 2011, proposing a two-stage implementation process (Transition Period Rules to be effective June 1, 2012; Full Integration Rules,[126] June 1, 2015 (later amended to June 1, 2016)).[127] NEPOOL did not support the ISO-NE compliance filing, with 51.9% voting to support the package at the August 12, 2011 Participants Committee meeting. On January 19, 2012, the FERC conditionally accepted New England's *Order 745* compliance filing, with the Transition Period Rules to be effective June 1, 2012 and Full Integration Rules effective June 1, 2016, as either in compliance with *Order 745* or just and reasonable under FPA § 205.[128] ISO-NE's 90-day compliance filing (providing further justification for using the Demand Reduction Threshold Price and amending the Transition Period rules to allow for ARCs to bid into the energy markets on behalf of smaller individual assets) was accepted on May 29, 2012.[129] A number

---

[121] 144 FERC ¶ 61,204 (Sep. 16, 2013); 147 FERC ¶ 61,026 (Apr. 8, 2014).

[122] 145 FERC ¶ 61,023 (Oct. 7, 2013); 147 FERC ¶ 61,027 (Apr. 8, 2014).

[123] *Transcanada Power Mktg. Ltd. v. FERC*, 2015 U.S. App. LEXIS 22304 (D.C. Cir. 2015).

[124] 138 FERC ¶ 61,042 (Jan. 19, 2012); 139 FERC ¶ 61,116 (May 17, 2012).

[125] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶ 61,187 (Mar. 11, 2015).

[126] The "Full Integration Rules" enable DR to (i) fully participate (make Demand Reduction Offers) in the Day-Ahead and Real-Time Energy Markets; (ii) provide Operating Reserve and participate in the Forward Reserve Market ("FRM")); and (iii) receive FCM obligations and compensation that are fully comparable with those of dispatchable generation resources.

[127] *See ISO New England Inc*. Order No. 745 Compliance Filing, Docket No. ER11-4336 (filed Aug 19, 2011).

[128] *ISO New England Inc.*, 138 FERC ¶ 61,042 (Jan. 19, 2012).

[129] *ISO New England Inc.*, Docket No. ER11-4336-005 (May 29, 2012) (unpublished letter order).

of parties requested rehearing of the January 19 Order, but the FERC denied rehearing on May 17, 2012.[130] EPSA and NEPGA petitioned the DC Circuit Court of Appeals for review of the FERC's January 19 and May 17, and, as noted above, that case has been held in abeyance pending resolution of the Federal Court challenges to *Order 745*.

The Transition Period rules were implemented on June 1, 2012, and have been in effect, subject to minor adjustment, since that time. With respect to the Full Integration Rules, the ISO included with an April 26, 2012 filing of FCM conforming changes, a request that implementation of the Full Integration Rules be pushed back another year, to June 1, 2017. That delay, together with the Market Rule changes, was accepted on January 14, 2013.[131] The Full Integration Rules have been clarified and revised several times since, with the most recently filed changes including a request, in light of the uncertainty created by the DC Circuit Order and Supreme Court review, to defer implementation of the Full Integration Rules one more year to June 1, 2018. That request was accepted December 23, 2015. Given the Supreme Court's January 25 Decision, in the time remaining before the Full Integration Rules are implemented on June 1, 2018, NEPOOL and ISO-NE will need to work together to identify, finalize, file, and implement any refinements to the Market Rules, Manuals, or other rules and procedures that may be necessary to support the full integration of DR in the New England's Markets as of June 1, 2018.

- **Orders 745 and 745-A (FERC v. EPSA, Supreme Court, 14-840 and 14-841)**
  Underlying FERC Proceedings: RM10-17-000[132]
  Appellants: FERC and EnerNOC

On January 25, 2016, the Supreme Court reversed the DC Circuit Court of Appeals' May 23, 2014 decision[133] vacating FERC Order 745.[134] As previously reported, the DC Circuit vacated *Order 745*[135] in its entirety as impermissibly encroaching on "states' exclusive jurisdiction to regulate the retail market". 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. 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," failing to reasonably consider and address arguments that *Order 745* will result in over-compensation of demand response resources.

The Supreme Court, however, held that the FPA does provide the FERC with the authority to regulate wholesale market operators' compensation of demand response bids, and the FERC's decision to compensate demand response providers at LMP instead of at LMP-G, is not arbitrary and capricious. As to the FERC's authority to regulate ISO/RTO compensation of DR bids, the Supreme Court reasoned that *Order 745* complies with the FPA's plain terms because the practices at issue directly affect wholesale rates and the FERC has not thereby regulated retail sales. The contrary view, the Court held, would conflict with the FPA's core purposes. As to compensation at LMP, the Court held that the FERC's serious and careful discussion of the issue (provided by its detailed explanation of its choice of LMP and response at length to contrary views) satisfies the arbitrary and capricious standard. In upholding FERC's choice of compensation at LMP, the Court did "not discount the cogency of EPSA's arguments in favor of LMP-G. Nor do we say that in opting for LMP instead, FERC made the better call. It is not our job to render that judgment, on which reasonable minds can differ. Our important but limited role is to ensure that the [FERC] engaged in reasoned decision-making—that it weighed competing views, selected a compensation formula with adequate support

---

[130] *ISO New England Inc.*, 139 FERC ¶ 61,116 (May 17, 2012).

[131] *ISO New England Inc.*, 142 FERC ¶ 61,027 (2013).

[132] 134 FERC ¶ 61,187 (Mar. 15, 2011); 137 FERC ¶ 61,215 (Dec. 15, 2011).

[133] *EPSA v. FERC*, 753 F.3d 216 (May 23, 2014), *reversed and remanded*.

[134] *FERC v. EPSA et al.*, 577 U. S. ____ (2016).

[135] *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.

in the record, and intelligibly explained the reasons for making that choice. FERC satisfied that standard." This matter will be remanded to the DC Circuit Court of Appeals for disposition of any remaining issues (e.g. the unresolved cost allocation issue raised by the CAISO and CA PUC). The remand will not issue for at least 25 days pursuant to Rule 45 of the Rules of the Supreme Court.

- **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. Since the last Report, the Solicitor General filed, on September 16, an amicus brief of the United States. On September 29, petitioner CPV Maryland filed a supplemental brief. The case was distributed on September 30 for the Court's October 16, 2015 Conference. The Supreme Court granted certiorari on October 19, 2015. Oral argument is set for one hour and has yet to be scheduled.

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[136] 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.[137] In affirming the District Court decision, the 4th Circuit found the MD PSC Order to be both field[138] and conflict pre-empted.[139]

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."[140] 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"),[141] 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 was "field preempted because it functionally sets the rate that CPV

---

[136] *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.

[137] *PPL EnergyPlus, LLC v. Nazarian*, 753 F.3d 467; 2014 U.S. App. LEXIS 10155.

[138] "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.

[139] "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."

[140] Slip op. at p. 14.

[141] *Id.* at p. 10.

receives for its sales in the PJM auction."[142] 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."[143] 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."[144]

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".[145] 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."[146] "Maryland's initiative disrupts [the PJM scheme] by substituting the state's preferred incentive structure for that approved by FERC."[147] "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."[148]

Petitions for rehearing *en banc* were filed by MD PSC and CPV Maryland on June 16, 2014. The Supreme Court granted certiorari on October 19, 2015. Oral argument is scheduled for February 24, 2016.

- **CPV Power Development, 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. Since the last Report, the Solicitor General filed, on September 16, an amicus brief of the United States. On September 29, petitioner CPV Maryland filed a supplemental brief. The case was distributed on September 30 for the Court's October 16, 2015 Conference.

As previously reported, on September 11, 2014, the 3rd Circuit Court of Appeals affirmed[149] the analogous October 11, 2013 decision of the United States District Court for the District of New Jersey declaring

---

[142] *Id.* at p. 16.

[143] *Id.* at pp. 18-19.

[144] *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.

[145] *Id.* at p. 27.

[146] *Id.* at p. 23.

[147] *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.")

[148] *Id.* at p. 25.

[149] *PPL EnergyPlus, LLC v. Hanna*, 977 F.Supp.2d 372 (D. NJ. Oct. 11, 2013); 2013 U.S. Dist. LEXIS 147273, ("*NJ Order*").

unconstitutional (and therefore null and void) New Jersey's Long Term Capacity Agreement Pilot Program Act ("LCAPP").[150] In affirming the New Jersey District Court's decision, the 3rd Circuit concluded:

> 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.[151]

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) (NDNY 5:15-cv-00230-DNH-TWD)**

Entergy[152] filed, on February 27, 2015, in the United States District Court for the Northern District of New York ("NDNY"), 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")[153] is preempted by the FPA and invalid under the dormant Commerce Clause of the US Constitution. Entergy also seeks a permanent injunction requiring the NYPSC Commissioners to withdraw the 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.

Since the last Report, the parties exchanged briefs regarding the import of a recent NYISO filing made with the FERC. On December 29, a previously-scheduled telephone conference was re-scheduled to February 23, 2016. A temporary stay of discovery remains in effect.

---

[150] *PPL EnergyPlus, LLC v. Hanna*, 766 F.3d 241; 2014 U.S. App. LEXIS 17557 (Sep. 11, 2014).

[151] *Id.* slip op. at 31.

[152] Plaintiffs are Entergy Nuclear FitzPatrick, LLC ("FitzPatrick"); Entergy Nuclear Power Marketing, LLC ("ENPM"); and Entergy Nuclear Operations, Inc. ("ENOI").

[153] 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.

INDEX
Status Report of Current Regulatory and Legal Proceedings as of February 4, 2016

I. Complaints/Section 206 Proceedings

206 Proceeding: 2014/15 RNS Recovery of SeaLink Development Costs ..... (EL15-85) 2
206 Proceeding: RNS/LNS Rates and Rate Protocols ..... (EL16-19) 1
206 Proceeding: Zonal Sloped Demand Curves ..... (EL16-15) 2
Base ROE Complaints (2012 and 2014) (Consolidated) ..... (EL13-33 and EL14-86) 4
Lotus Energy Waiver Request ..... (EL16-22) 8
NEPGA DR Capacity Complaint ..... (EL15-21) 4
New Entry Pricing Rule Complaint ..... (EL15-23) 3
PURPA Complaint: Allco Renewable Energy v. CT Agencies ..... (EL16-11 et al.) 19

II. Rate, ICR, FCA, Cost Recovery Filings

206 Proceeding: 2014/15 RNS Recovery of SeaLink Development Costs ..... (EL15-85) 2
206 Proceeding: RNS/LNS Rates and Rate Protocols ..... (EL16-19) 1
Base ROE Complaints (2012 and 2014) (Consolidated) ..... (EL13-33 and EL14-86) 4
Base ROE Complaint (2011) Refund Reports ..... (EL11-66) 5
Eversource CCRP Cost Treatment Proposal ..... (ER16-116) 7
FCA1 Results Remand Proceeding ..... (ER08-633) 7
FCA10 Qualification Informational Filing ..... (ER16-308) 6
ICR-Related Values and HQICCs - 2016/17 ARA3, 2017/18 ARA2, 2018/19 ARA1 ..... (ER16-446) 5
ICR, HQICCs and Related Values - 2019/20 Power Year ..... (ER16-307) 6

III. Market Rule and Information Policy Changes, Interpretations and Waiver Requests

206 Proceeding: Zonal Sloped Demand Curves ..... (EL16-15) 2
CSO Termination: Spruce Mountain Wind ..... (ER16-864) 9
CTS Conforming Changes ..... (ER15-2641) 12
CTS Winter Reliability Program Cost Allocation Correction ..... (ER16-462) 11
De-List Bid Information Release Change ..... (ER16-538) 10
Demand Curve Changes ..... (ER14-1639) 11
FCM Resource Retirement Reforms ..... (ER16-551) 10
Jump Ball Filing: Winter Reliability Program ..... (ER15-2208) 11
Lotus Energy Waiver Request ..... (EL16-22) 8
NEPGA DR Capacity Complaint ..... (EL15-21) 4
New DNE Dispatch Changes Effect Date ..... (ER16-870) 9
New Entry Pricing Rule Complaint ..... (EL15-23) 3
Status of New England Implementation of *Order 745* 37
Waiver Request: FCM Qualification Lock-In Election (Calpine) ..... (ER16-708) 9

IV. OATT Amendments/Coordination Agreements

CTS Conforming Changes ..... (ER15-2641) 12
Eversource CCRP Cost Treatment Proposal ..... (ER16-116) 7
RSP Timing Changes ..... (ER16-819) 12

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Updates

Schedule 21-EM: Emera Maine/Covanta Maine LTSA Terminations ..... (ER16-840) 12
Schedule 21-NSTAR: Fore River LGIA Termination Notice ..... (ER16-816) 13

VII. NEPOOL Agreement/ Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

IMM Quarterly Markets Reports - 2015 Fall ..... (ZZ15-4) 14
LFTR Implementation: 29th Quarterly Status Report ..... (ER07-476; RM06-08) 13
Opinion 531-A Refund Report: FG&E ..... (EL11-66) 13
Opinions 531-A/531-B Local Refund Reports ..... (EL11-66) 13

IX. Membership Filings

February 2016 Membership Filing ..... (ER16-836) 14
Involuntary Termination of Membership: NAPP ..... (ER16-820) 14
Involuntary Termination of Membership: Negawatt ..... (ER16-818) 14
January 2016 Membership Filing ..... (ER16-670) 14
Suspension Notice (Lotus Danbury LMS100 One) ..... (not docketed) 14
Suspension Notice (Lotus Danbury LMS100 Two) ..... (not docketed) 14

X. Misc. - ERO Rules, Filings; Reliability Standards

Compliance Filing: BES Exclusions for Local Network Configurations ..... (RM12-6) 18
Glossary Definition Changes ..... (RD16-3) 15
NOPR: BAL-002-1a Interpretation Remand ..... (RM13-6) 18
NOPR: New Reliability Standard: PRC-026-1 ..... (RM15-8) 17
NOPR: New Reliability Standard: TPL-007-1 ..... (RM15-11) 16
NOPR: Revised Rel. Standard: MOD-001-2 ..... (RM14-7) 17
Order 822: Revised Rel. Standards: CIP-003-6, CIP-004-6, CIP-006-6, CIP-007-6,
CIP-009-6, CIP-010-2, CIP-011-2 ..... (RM15-14) 15
Revised Regional Delegation Agreements ..... (RR15-12) 18
Revised Reliability Standard: BAL-002-2 ..... (RM16-7) 15
Rules of Procedure Changes ..... (RR16-2) 18

XI. Misc. Regional Interest

203 Application: Calpine/Granite Ridge ..... (EC16-19) 19
203 Application: Narragansett/Entergy Rhode Island State Energy ..... (EC16-50) 19
203 Application: Passadumkeag Wind Park (SunEdison/ Quantum) ..... (EC15-217) 19
203 Application: ReEnergy Sterling ..... (EC16-58) 19
Cost Sharing Agreements (Greater Boston Area Transmission Solution Plan):
National Grid, NSTAR, PSNH ..... (ER16-878, -879, -882) 20
D&E Agreement NSTAR/Exelon West Medway ..... (ER16-509) 21
D&E Agreement NSTAR/NRG Canal ..... (ER16-510) 21
Emera MPD OATT Changes ..... (ER15-1429; EL16-3) 21
FERC Audit of ISO-NE ..... (PA16-6) 24
FERC Enforcement Action: Formal Investigation
(MISO Zone 4 Planning Resource Auction Offers) ..... (IN15-10) 23
FERC Enforcement Action: Show Cause Order – Coaltrain et al. ..... (IN16-4) 23
FERC Enforcement Action: Show Cause Order (Etracom/M. Rosenberg) ..... (IN16-2) 24
FERC Enforcement Action: Staff NoV (Berkshire/Powerplant Management Services) 24
FirstEnergy PJM DR Complaint ..... (EL14-55) 20

LGIA: National Grid/Wheelabrator Saugus ..... (ER16-760) 20
LGIA – PSNH/Schiller Generating Station ..... (ER16-391) 21
MISO Methodology to Involuntarily Allocate Costs to Entities Outside Its Control Area .. (ER11-1844) 22
PURPA Complaint: Allco Renewable Energy v. CT Agencies ..... (EL16-11 et al.) 19
SGIA: CMP/Hackett Mills Hydro ..... (ER16-518) 20

XII. Misc: Administrative & Rulemaking Proceedings

AWEA Petition for LGIA/LGIP Rulemaking ..... (RM15-21) 27
NOPR: Connected Entity Data Collection ..... (RM15-23) 26
NOPR: Price Formation Fixes - Price Caps in RTO/ISO Markets ..... (RM16-5) 25
NOPR: Price Formation Fixes - Settlement Intervals/Shortage Pricing ..... (RM15-24) 25
NOPR: Reactive Power Requirements for Wind Generators ..... (RM16-1) 25
Order 816: MBR Authorization Refinements ..... (RM14-14) 28
Price Formation in RTO/ISO Energy and Ancillary Services Markets ..... (AD14-14) 25
White Paper: Guidance Principles on Clean Power Plan Modeling ..... (AD16-14) 24

XIII. Natural Gas Proceedings

Enforcement Actions: BP Initial Decision ..... (IN15-13) 32
Enforcement Actions: Staff NoV: Total Gas & Power, North America, Inc. 32
New England Pipeline Proceedings 32
Opinion 538: ANR Storage Company, Order on Initial Decision ..... (RP12-479) 31
Order 809: Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities ..... (RM14-2) 29
Order 820: Delegation of Authority for FERC Form No. 552 ..... (RM16-4)**Error! Bookmark not defined.**
Posting of Offers to Purchase Capacity (Section 5 Proceeding) ..... (RP14-442) 31
Rice Energy Marketing, Order on Petition for Declaratory Order ..... (RP15-1089) 30
Section 5 Investigation: Columbia ..... (RP16-302) 28
Section 5 Investigation: Empire ..... (RP16-300) 28
Section 5 Investigation: Iroquois ..... (RP16-301) 28
Section 5 Investigation: Tuscarora ..... (RP16-299) 28

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

2013/14 Winter Reliability Program and Bid Results ..... 14-1104 (DC Cir.) 37
Base ROE Complaint (2011) ..... 15-1118 (DC Cir.) 35
Base ROE Complaints (2012 and 2014) ..... 15-1212 (DC Cir.) 35
CPV Maryland, LLC v. PPL EnergyPlus et al. ..... 14-623 (Supreme Court) 39
CPV Power Development, Inc., et al. v. PPL EnergyPlus, LLC, et al. ..... 14-634/694 (Supreme Ct) 40
Entergy Nuclear Fitzpatrick, LLC et al. v. Zibelman et al. ..... 5:15-cv-00230 (N.D.N.Y.) 41
FCM Administrative Pricing Rules Complaint ..... 15-1071 (DC Cir.) 35
FCM Jump Ball and Compliance Proceedings ..... 16-1023 (DC Cir.) 34
FCA8 Results ..... 14-1244 (DC Cir.) 36
New England's *Order 745* Compliance Filing ..... 12-1306 (DC Cir.) 37
NEPGA Peak Energy Rent (PER) Complaint ..... 16-1024 (DC Cir.) 34
Orders 745/745-A ..... 14-840 (Supreme Court) 38
Order 1000 Compliance Filings ..... 15-1139 (DC Cir.) 35
Status of New England Implementation of *Order 745* 37

SEAPORT HOTEL

FROM Points West via I-90:

Follow the Massachusetts Turnpike/Interstate 90 East to Exit 25 – South Boston. At the top of the ramp, bear left towards Seaport Boulevard. At the first set of lights, proceed straight onto East Service Road. At the next set of lights, take a right onto Seaport Boulevard. The Seaport Boulevard entrance to the Seaport Garage is located ahead on the right.

FROM Points South via I-93:

Heading northbound on I-93 towards Boston, take Exit 20, which will be immediately after Exit 18. Follow the signs to “I-90 East.” Take the first tunnel exit to "South Boston.” At the first set of lights at the top of the ramp, proceed straight onto East Service Road. At the next set of lights, take a right onto Seaport Boulevard. The Seaport Boulevard entrance to the Seaport Garage will be ahead on the right.

FROM Points North via I-93:

Heading southbound on Interstate 93 Boston, take Exit 23, Purchase Street and move into the left lane. At the top of the ramp, take a left turn onto the Evelyn Moakley Bridge/Seaport Boulevard. Follow Seaport Boulevard for approximately .8 miles, the Seaport Boulevard entrance to the Seaport Garage will be on the right, after the Seaport Boulevard/B Street intersection.

FROM Logan International Airport and Route 1A South:

Follow the signs towards I-90 West - Ted Williams Tunnel. Take the Ted Williams Tunnel to Exit 25. At the top of the ramp proceed straight onto B Street. Follow B Street to the end and take a right onto Seaport Boulevard. The Seaport Boulevard entrance to the Seaport Garage will be on your right.

PUBLIC TRANSPORTATION

The MBTA Silver Line Waterfront (SL1) provides service from the WTC Station to Logan International Airport terminals every 10 minutes during the weekday and every 15 minutes during the weekend. The Silver Line station is located adjacent to the hotel.

Seaport Boston is about 3 miles from Logan Airport, one of several hotels near the Boston Convention Center and a quick ride away from all Boston attractions. Taxis are readily available from the lobby of our hotel.

This scenic way to travel is a great way to avoid traffic. Hop on the water taxi shuttle at your terminal and enjoy the ride. The stop for pick up and drop off is at the Seaport World Trade Center, directly across the street from the Seaport hotel.