FINAL

A meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Friday, August 7, 2015. 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, and reviewed appropriate protocol for the teleconference meeting.

APPROVAL OF MINUTES OF JUNE 5 AND JUNE 23-25, 2015 MEETINGS

Mr. Gordon referred the Committee to the preliminary minutes of the June 5 and June 23-25, 2015 meetings that had been circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the June 5 and June 23-25, 2015 meetings were unanimously approved with non-material clarifications.

CONSENT AGENDA AND ISO SELF-FUNDING TARIFF CTS-RELATED REVISIONS

Mr. Gordon referred the Committee to the Consent Agenda circulated in advance of the meeting and to the memorandum and materials describing changes to the ISO Self-Funding Tariff relating to Coordinated Transaction Scheduling (CTS) as recommended by the Budget & Finance Subcommittee. Mr. Gordon proposed that, absent objection, motions to approve the Consent Agenda and the ISO Self-Funding Tariff CTS revisions be voted together. There was no objection. Accordingly, a motion to approve the Consent Agenda and the following motion to support the ISO Self-Funding Tariff CTS revisions, each duly made and seconded, were unanimously approved without comment:

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

REPORT OF THE ISO CHIEF EXECUTIVE OFFICER

Mr. Gordon van Welie, ISO Chief Executive Officer, was unable to attend. In his absence, Mr. Raymond Hepper, ISO General Counsel, referred the Committee to the summary of the June 9, June 22 and July 16, 2015 ISO Board and Board Committee meetings, which had been circulated and posted in advance of the meeting. There were no questions or comments on that summary.

REPORT OF THE ISO CHIEF OPERATING OFFICER

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), referred the Committee to the COO report that had been circulated and posted in advance of the meeting. Before discussing the July results, though, he stated that there previously had not been a June COO report because of the timing of NEPOOL's early June and Summer Meetings, but at the request of the NEPOOL Officers, the ISO would publish a June COO report of market operations, somewhat condensed from the monthly reports published for each of the regular NEPOOL Participants Committee meetings. He then summarized highlights from the COO report that had been circulated, noting that the report reflected July data through July 29 (through July 28 for Real-Time NCPC). He reported that in July: (i) Energy Market value was $337 million, down $29 million from June 2015, and down $174 million from July 2014; (ii) natural gas prices were 12.5% higher than June 2015 average prices; (iii) Real-Time Hub locational marginal prices (LMPs) on average were 30% higher than June 2015 LMPs; (iv) average (peak hour) Day-Ahead cleared physical Energy, as a percentage of forecasted load, was 99.1% in July 2015, up from

97.9% in June 2015; and (v) Net Commitment Period Compensation (NCPC) totaled $4.3 million (1.3% of the total Energy Market value), down $5.1 million from June 2015 and down $5.4 million from July 2014. Of that $4.3 million in NCPC, he reported that $4.1 million was for first contingency payments (down $593,000 from June) and $181,000 for second contingency payments, which were all in New Hampshire (down $4.4 million from June 2015). Voltage support payments for July were $77,000, down $115,000 from June. In response to a question regarding second contingency charges allocated to Northeastern Massachusetts (NEMA) in June, Dr. Chadalavada stated there was a reallocation of some of those charges to network load based on the trigger conditions that were established and reflected in the Market Rules. He reported the total second contingency costs for NEMA in June were approximately $4.6 million, and based on the trigger conditions that were applied, $1.8 million was to be reallocated to network load based on minimum capacity requirements.

Dr. Chadalavada stated the summer 2015 had been mostly mild, with only a limited number of days when the temperature was 90° or higher with dew points in the mid to upper 60° range. He reported the June peak occurred on June 23 and was 20,742 MW. He said there were five days in July when the load exceeded 22,000 MW, with a peak of 24,398 MW experienced on July 20 at 17:00. He stated that the system peak hour had shifted from prior years to one to two hours later in the day, which he explained was the result of increased solar resources available to serve load earlier in the day. He reported the ISO was evaluating its forecasting capabilities and seeking to apply lessons learned with regard to the load pattern in order to make future forecasts more accurate and reliable. In this regard, he indicated that the ISO was working to compare summer 2015's data to data from the past several years where similar weather was experienced. Once that analysis was complete, the ISO would engage with NEPOOL to discuss any implications or lessons learned.

Turning to highlights of the Forward Capacity Market (FCM), Dr. Chadalavada reported: the transfer limits and requirements development discussion was continuing at the Power Supply Planning Committee (PSPC), with a FERC filing due by November 10; new resource qualification packages were being reviewed by the Internal Market Monitor and System Planning, with Qualification Notification Determinations to be sent to Participants by September 26; and the Non-Price Retirement Request window was open, and would close on October 12, with only one retirement received by the date of the meeting and representing less than 5 MW.

Dr. Chadalavada then referred the Committee to an update of the 2014/15 Winter Reliability Program, which he stated would be included in each monthly report until all results of the program had been reported. He said there was no change from the prior month.

In response to questions regarding Local Second Contingency payments in NEMA, Dr. Chadalavada stated that, at certain load levels, the ISO must have enough resources online to preserve reliability, and some of those necessary resources are committed out of merit order. To the extent such resources clear in merit order, no uplift would be required to be paid either Day-Ahead or Real-Time. Compared to June, July had higher load levels which resulted in fewer resources being required to be committed out-of-merit. Dr. Chadalavada declined to identify the load levels that typically result in higher out-of-merit commitments until he had a chance to ensure with his legal advisors that such disclosure would be permitted.

In response to a request from the End User Sector at the Summer Meeting Board/Sector meetings, Dr. Chadalavada highlighted a one-time exhibit in the report illustrating the highest natural gas supply days during the 2014/15 winter, as determined by pipeline utilization greater than or equal to 85% of pipeline operating capacity.

IMM 2014 ANNUAL MARKETS REPORT AND 2015 Q1 SUMMARY

Dr. Jeffrey McDonald, ISO Internal Market Monitor (IMM), reviewed highlights from a summary presentation of the 2014 Annual Markets Report and 2015 Quarter 1 (Q1) Report, which had been circulated and posted in advance of the meeting. Turning to the 2014 Annual Markets report, he reported that, in 2014:

- Wholesale electricity costs increased by approximately 12% due to higher natural gas prices during Q1 2014.
- NCPC increased from $158 million to $174 million due to the operation of expensive generation during extreme cold weather in Q1 2014.
- The Energy Market was structurally competitive, with low levels of concentration on average throughout the year.
- Energy Market Offer Flexibility (EMOF), which went into effect on December 3, 2014, improved the ability of a generator to reflect in its energy offer the cost of procuring fuel for each hour of the Operating Day and to update the cost in Real-Time.
- The Eighth Forward Capacity Auction (FCA8) was the first FCA conducted without a floor price, with a number of administrative pricing rules triggered, including Insufficient Competition (prices of $15 and $7.03/kW-month).
- Rule changes were, and continued to be, developed to address the ISO's FCM market power concerns.
- The cost of procuring system-wide Operating Reserves through the Forward Reserve Market (FRM) increased, caused by an increase in Operating Reserve requirements and a change in the non-performance penalty structure.
- Payments to suppliers providing regulation services increased in 2014 compared to 2013, due to increased natural gas prices, as well as changes in regulation services rules implemented in July 2013.
- Energy consumption decreased modestly (by 2%) relative to 2013.

In response to questions on a comparison of the electricity prices and natural gas prices for Day-Ahead LMPs, Real-Time LMPs, and Algonquin prices, for Q1 2013 versus Q1 2014, and the remainder of 2013 versus the remainder of 2014, Dr. McDonald stated that the chart was intended to show the correlation between them, noting that the Algonquin price was on a different index than the dollars per megawatt. He committed to review the reason for the

apparent change in heat rate reflected in the comparison and to report back to those asking for that information.

Dr. McDonald reported that the IMM tested the market structure for competitiveness at the system level using a number of industry-standard methods. Under the C4 index, he reported that four of the largest generation Participants provided 40% of the total electricity produced for 2014's peak hour on July 2, 2014. He said that four of the largest load-serving participants served 35% of the total system load during that peak hour. He reported that the Residual Supply Index (RSI) results, a single supplier withholding measure, were consistent with a structurally competitive market, noting that pivotal suppliers were present during 37 hours in 2014, approximately 0.4% of all 8,760 hours in the year.

Dr. McDonald then summarized the results of FCA8 and referred the Committee to a chart reflecting results of FCA9 for new resources versus existing resources. He reported that, for FCA9, there was a new zone in Southeastern Massachusetts-Rhode Island (SEMA-RI) with insufficient competition that resulted in a clearing price at the cap of $17.73/kW-month. Focusing system-wide (including NEMA and Connecticut (CT)), he said that there was a considerable amount of new entrants in FCA9, including a 725 MW dual-fuel resource and 245 MW resource in CT, a 198 MW resource in SEMA-RI, and approximately 367 MW of new demand-side resources (with resources, other than those in SEMA-RI, clearing at $9.55). On the interfaces, he reported there was an abundance of supply and sufficient competition, with capacity across the New York AC Ties clearing at $7.97, and capacity across the New Brunswick interface clearing at $3.94, each of which was below the clearing price for the rest of the system. He concluded that there was considerable competition on the interfaces and in the zones that were not SEMA-RI.

Dr. McDonald received a question concerning his primary recommendation on virtual transactions, given the decline in virtual transactions. He explained his view that Day-Ahead and Real-Time price spreads could be further converged if there were more virtual transactions. He referred to statistics reported on the percentage of hours where different types of offers were marginal, indicating that virtual transactions were marginal a very significant portion of the time (about 30%). This statistic, he explained, suggested that there was a fairly liquid supply of virtuals in the range of the expected market clearing price that was helping provide liquidity for the market clearing. He stated it would be prudent to review the extent to which NCPC is allocated to virtuals to make sure that the allocation was following cost causation principles and not inhibiting additional liquidity in the Day-Ahead Energy Market.

Dr. McDonald then reviewed highlights from Q1 2015, reporting $3.14 billion in estimated wholesale market costs, a 41% decrease from Q1 2014. He explained that the primary drivers for the decrease in total energy costs were lower natural gas prices, averaging $11.37/MMBtu, a decrease of 42% from Q1 2014, and oil prices 51% lower than in Q1 2014. He reported $36 million in total NCPC payments, a decrease of 67% from Q1 2014. He stated there had been a significant increase in the frequency of negative LMPs since EMOF was implemented, occurring in 0.6% of total intervals.

In reviewing key statistics from Q1 2015, Dr. McDonald continued to focus on the high correlation between average Day-Ahead and Real-Time Energy Hub prices and the average natural gas price, with a 43% decrease in natural gas prices, and comparable decreases in Day-Ahead (41%) and Real-Time (43%) Hub prices. He posited that the 2014/15 Winter Program, which provided substitutes for natural gas, and increased deliveries of liquefied natural gas (LNG) injected into and through New England (double the volume from the prior winter) likely

also contributed to the decreased Hub prices, by helping to reduce the extent to which the region had to lean on a constrained natural gas system and mitigate the price volatility and higher price impact of natural gas.

Dr. McDonald concluded his presentation by referring to charts regarding EMOF and the utilization of offer flexibility and negative LMPs. The first chart reflected the average number of offer block price revisions by fuel type and hour in the Real-Time Energy Market in Q1 2015. At the beginning of the new gas day (late morning) there was a high frequency of offers changed after the reoffer period was closed, taking advantage of offer flexibility. He indicated that the data did not indicate that offer flexibility was being leveraged in the beginning of the gas day by other fuel types (hydro, fuel oil and coal). He explained, however, that the data did show additional utilization of energy offer flexibility early in the morning by gas-fired resources, which he opined may reflect resources seeking to position themselves for the load ramp.

Dr. McDonald then reviewed a second chart in his presentation that reflected the number of five-minute Real-Time pricing intervals with negative LMPs by load zone in Q1 2015. He explained, in response to clarifying questions on negative LMPs, that there were very few hours (less than a handful) with negative Day-Ahead LMPs and those occurrences were not of concern. In Real-Time, negative LMPs had been seen during very early morning off-peak hours, when self-scheduled rather than resources economically-scheduled were prevalent in the supply stack. He expected that virtual bids would arbitrage those negative LMPs away to the extent that the occurrence of negative prices was predictable, but he had to that point found such predictability with respect to New England's off-peak negative prices lacking. Dr. McDonald confirmed in response to another question that there was a learning curve for Participants that might have impacted early experiences with negative pricing, but that would resolve over time. Related, he

reported there was more intensity and frequency in Real-Time Energy negative pricing in the first 30 - 45 days following the implementation of EMOF, but that negative pricing has been less frequent since then. In response to how the non-dispatchability of some resources may have effected this and how that might change in 2016 with the implementation of the economic dispatch rules, Dr. McDonald predicted that, over the next year, there would be more dispatchability in general, as Participants determined what the best strategy was for each resource for addressing over generation or over supply conditions, which he explained would result in less price-insensitive scheduling, particularly in off-peak hours.

LITIGATION REPORT

Mr. Doot referred the Committee to the August 6 Litigation Report that had been circulated and posted the day before the meeting. He highlighted the pleadings in the Winter Reliability Program jump ball proceeding. He noted that the Transmission Owners had filed the 2015/16 RNS transmission rate that they had reviewed with Participants at the Transmission Committee Summer Meeting. He reported that oral argument schedules were being established for the fall in the pending appeals before the Supreme Court and Federal District Courts of Appeal. Mr. Patrick Gerity, NEPOOL Counsel, highlighted that the FCA1 resettlement figures had been filed by the ISO and reminded the Connecticut parties that comments were due in ten days.

COMMITTEE REPORTS

Each of the Vice-Chairs of the Technical Committees reported on the schedule for committee meetings in August. Mr. Dell Orto reported that the Budget & Finance Subcommittee (Subcommittee) was scheduled to meet twice in August, on August 13 following the conclusion of the Markets Committee Summer Meeting and on August 26, where drafts of the 2016 ISO and

NESCOE budgets would be considered. Mr. Doot highlighted for the Committee that the Subcommittee would be considering at its August 13 meeting amendments to eliminate the NEPOOL Review Board arrangements at year's end, which he said also would be reviewed with the Review Board Liaison Committee, ahead of a planned vote at the September 11 Participants Committee meeting to ballot those amendments.

OTHER BUSINESS

Mr. Doot reminded members of the September 11 Participants Committee meeting scheduled at the Seaport Word Trade Center, to be preceded by the ISO's 2015 Regional System Plan public meeting the day before, also at the Seaport Word Trade Center. He noted that the Participants Committee meetings for the remainder of 2015 would be also be held in Boston: October 2 at the Colonnade Hotel, November 6, with the ISO Board and Sector breakout meetings, at the Hilton Logan Hotel, and December 4 (the 2015 Annual Meeting) at the Colonnade Hotel.

There being no further business, the meeting adjourned at 11:19 a.m.

Respectfully submitted,

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David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE
AUGUST 7, 2015 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
American PowerNet Management	Supplier			Mary Smith
Ashburnham Municipal Light Plant	Publicly Owned		Mike Lynch	
Associated Industries of Massachusetts	End User			Roger Borghesani
Belmont Municipal Light Department	Publicly Owned		Phil Smith	
Boylston Municipal Light Department	Publicly Owned		Mike Lynch	
BP Energy Company	Supplier			Nancy Chafetz
Calpine Energy Services, LP	Supplier		Brett Kruse	
Central Maine Power Company	Transmission	Eric Stinneford		
Chester Municipal Electric Light Department	Publicly Owned	Phil Smith		
Chicopee Municipal Lighting Plant	Publicly Owned		Mike Lynch	
Citigroup Energy Inc.	Supplier	Barry Trayers		
CLEAResult Consulting, Inc.	AR	Doug Hurley		
Concord Municipal Light Plant	Publicly Owned		Phil Smith	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Danvers Electric Division	Publicly Owned		Phil Smith	
Dominion Energy Marketing, Inc.	Generation	Jim Davis		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Emera Maine	Transmission	Jeff Jones	Jose Rotger	Stacy Dimou Sandi Hennequin Andrew McCullough
Energy America, LLC	Supplier			Nancy Chafetz
EnerNOC, Inc.	AR	Herb Healy		
Entergy Nuclear Power Marketing, LLC	Generation		Ken Dell Orto	Bill Fowler
Essential Power, LLC	Generation	M.Q. Riding	Bill Fowler	
Eversource Energy	Transmission		Joseph Staszowski	
Exelon Generation Company	Supplier		Bill Fowler	
Galt Power, Inc.	Supplier	Nancy Chafetz		
GDF SUEZ Energy Marketing NA, Inc.	Generation	Thomas Kaslow		
Generation Group Member	Generation			Bob Stein
Georgetown Municipal Light Department	Publicly Owned		Phil Smith	
Granite Ridge/Merrill Lynch	Supplier		Bill Fowler	
Groton Electric Light Department	Publicly Owned		Mike Lynch	
Groveland Electric Light Department	Publicly Owned		Phil Smith	
H.Q. Energy Services (U.S.) Inc.	Supplier		Bob Stein	
Harvard Dedicated Energy Limited	End User	Mary Smith		Roger Borghesani Paul Peterson
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Phil Smith	
Holden Municipal Light Department	Publicly Owned		Mike Lynch	
Holyoke Gas & Electric Department	Publicly Owned			Mike Lynch
Hudson Light and Power Department	Publicly Owned		Mike Lynch	
Hull Municipal Lighting Plant	Publicly Owned		Mike Lynch	
Industrial Energy Consumer Group	End User	Don Sipe		
Ipswich Municipal Light Department	Publicly Owned		Mike Lynch	
Jericho Power, LLC	AR		Phil Smith	
Long Island Lighting Company (LIPA)	Supplier		William Killgoar	
Littleton (MA) Electric Light & Water Department	Publicly Owned		Phil Smith	
Maine Skiing, Inc.	End User	Don Sipe		
Mansfield Municipal Electric Department	Publicly Owned		Mike Lynch	

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PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN THE
AUGUST 7, 2015 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Marblehead Municipal Light Department	Publicly Owned		Mike Lynch	
Massachusetts Attorney General's Office (MA AG)	End User	Fred Plett	Christina Belew	
Mass. Development Finance Agency	Publicly Owned		Phil Smith	
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned	Mike Lynch		
Merrimac Municipal Light Department	Publicly Owned		Phil Smith	
Middleborough Gas and Electric Department	Publicly Owned		Mike Lynch	
Middleton Municipal Electric Department	Publicly Owned		Phil Smith	
National Grid	Transmission	Timothy Brennan	Timothy Martin	
New Hampshire Electric Cooperative (NHEC)	Publicly Owned		Steve Kaminski	Brian Forshaw
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson		
Noble Americas Gas & Power Corp.	Supplier		Becky Merola	
NRG Power Marketing, Inc.	Generation	Dave Cavanaugh		
Pascoag Utility District	Publicly Owned		Phil Smith	
Paxton Municipal Light Department	Publicly Owned		Mike Lynch	
Peabody Municipal Light Plant	Publicly Owned		Mike Lynch	
Princeton Municipal Light Department	Publicly Owned		Mike Lynch	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Repsol Energy North America Company	Supplier		Nancy Chafetz	
Rowley Municipal Lighting Plant	Publicly Owned		Phil Smith	
Russell Municipal Light Dept	Publicly Owned		Mike Lynch	
Shrewsbury Electric & Cable Operations	Publicly Owned		Mike Lynch	
Small Load Response Group Member	AR	Doug Hurley		
South Hadley Electric Light Department	Publicly Owned		Mike Lynch	
Sterling Municipal Electric Light Department	Publicly Owned		Mike Lynch	
Stowe Electric Department	Publicly Owned		Phil Smith	
SunEdison (First Wind Energy Marketing, Inc.)	AR	John Keene		Bob Stein
Tangent Energy Solutions	Provisional Member	Brad Swalwell		
Taunton Municipal Light Department	Publicly Owned		Phil Smith	
Templeton Municipal Lighting Plant	Publicly Owned		Mike Lynch	
The Energy Consortium	End User	Roger Borghesani	Mary Smith	Paul Peterson
United Illuminating Company	Transmission		Alan Trotta	
Utility Services, Inc.	End User			Paul Peterson
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	Joe Wadsworth		
Wakefield Municipal Gas and Light Department	Publicly Owned		Mike Lynch	
Wallingford DPU Electric Division	Publicly Owned		Phil Smith	
Wellesley Municipal Light Plant	Publicly Owned		Phil Smith	
West Boylston Municipal Lighting Plant	Publicly Owned		Mike Lynch	
Westfield Gas & Electric Light Department	Publicly Owned		Mike Lynch	

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