FINAL

A meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Friday, January 9, 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 DECEMBER 5, 2014

Mr. Gordon referred the Committee to the preliminary minutes of the December 5, 2014 meeting that were circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the December 5, 2014 meeting were unanimously approved without change.

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.

REPORT OF THE ISO CHIEF EXECUTIVE OFFICER

Mr. van Welie referred the Committee to the summaries of the December 18, 2014 and January 6, 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 report.

Mr. van Welie reported that the ISO, NEPOOL Officers, and NECPUC representatives met the prior day to review a draft 2015 Work Plan (Work Plan). He stated that the ISO would refine the draft Work Plan based on feedback it received at that meeting and circulate it for Participants' review late in January and for presentation at the February 6 Participants Committee meeting.

REPORT OF THE ISO CHIEF OPERATING OFFICER

Dr. Vamsi Chadalavada, ISO Chief Operating Officer, reviewed highlights from the January COO report, which had been circulated and posted in advance of the meeting. Focusing on report highlights, which he noted reflected experiences through December 30 (except Daily Net Commitment Period Compensation (NCPC) through December 26), he stated that in December: (i) Energy Market value was $498 million, down $662 million from December 2013; (ii) natural gas prices were 2.6% lower than November 2014 average values; (iii) Real-Time Hub locational marginal prices (LMPs) on average were 6.5% lower than November 2014 LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percentage of forecasted load, was 99.7% in December 2014, up from 96.7% in November 2014; (v) daily NCPC for December 2014 (through December 26) totaled $12.2 million, up $5.4 million from November 2014 and down $7.9 million from December 2013; (vi) first contingency payments, totaling $11.4 million, were $8.2 million higher than November's; (vii) second contingency payments totaled $43,000, down from the $3 million in November; (viii) voltage support payments totaled $798,000, up $154,000 from November; and (ix) NCPC payments were 2.5% of the total Energy Market value.

He reported that the ISO scheduled for discussion at the January 21 Planning Advisory Committee meeting the 2015 Regional System Plan scope of work. He said that the final 2013

Emissions Report was posted on December 30 and a Distributed Generation Forecast Working Group meeting was scheduled for February 27. He went on to report that the ninth Forward Capacity Auction (FCA9) for the 2018/19 Capacity Commitment Period (CCP) was scheduled to begin on February 2, and that the show of interest window for the tenth Forward Capacity Auction (FCA-10) for the 2019/2020 CCP was scheduled to be open from February 17 through March 3.

Members then asked clarifying questions. Responding to questions concerning NCPC, Dr. Chadalavada explained that the new Energy Market Offer Flexibility (EMOF) Market Rules allowed for negative pricing, and that there were almost 43 hours of negative pricing in Real-Time. As a result, there were higher make-whole payments reflected as NCPC. Also in response to questions, he reported that there was a reduced need in December for supplemental commitments for reliability in the Day-Ahead Market.

Turning next to the 2014/15 Winter Reliability Program, Dr. Chadalavada highlighted the following:

- In the oil component of the program, 81 units were participating in the program, with a total of 3.8 million barrels of oil eligible for compensation after program limits were applied, for a maximum cost exposure to consumers of $68.7 million (when all available oil was added to the amount that could be compensated, a total of nearly 4.4 million barrels of oil was available as of December 1)

- In the liquefied natural gas (LNG) component, 6 units were participating, with a total of 500,000 MMBtu of LNG, for a maximum cost exposure of $1.5 million

- In the demand-side component, 3 assets were participating, with 14 MW that could be provided, for a maximum cost exposure of $75,600

Responding to a prior request to break out Winter Program commissioning costs by year, Dr. Chadalavada reported expected maximum commissioning costs of $3.56 million in 2014/15 and $2.19 million in 2015/2016, for a total of $5.75 million. He said that actual commissioning costs incurred under the Program through January 1, 2015 were $980,000. Providing additional detail, he noted that, of the 6 units participating in the Dual-Fuel Commissioning (DFC) Program, 4 units were to be commissioned for 2014/15 (1,039 MW) and 2 units were to be commissioned for 2015/16 (735 MW), representing a total winter seasonal claimed capability of 1,774 MW. A member requested further breakdown of the expected commissioning costs after the $980,000 already incurred, which Dr. Chadalavada committed to do, if possible, in the February COO report. In response to further questions, Dr. Chadalavada explained that the two units that were not yet commissioned in the DFC Program as of January 1 for Winter 2015/16 were qualified for prorated compensation over two years.

Also in response to a prior request, he reported that 550,401 barrels of Winter Program oil were used in December, with none of the LNG used. He explained in response to a question that this oil was consumed notwithstanding very mild weather because there was no limitation requiring that Winter oil be used solely for reliability; units in the Program could burn oil for whatever reason they chose. He explained, by way of example, that a dual-fuel unit in the Program that had oil and was expecting the next shipment of oil by a date certain was not prevented from using the Program oil. He stated that ISO dispatch is based on economics and not whether the fuel to be consumed was available under the Program.

Turning to an update on the experiences under the new EMOF provisions, Dr. Chadalavada responded to inquiries about the negative pricing experiences. He reported that the hourly markets continued to function well, with some minor glitches that had not created problems, either from a commitment and dispatch standpoint or from a Participant standpoint, in terms of offers into the system. The number of resources using the additional flexibility allowed in hourly energy offers was increasing, growing from 36-40 units previously using both the intraday offers and the negative pricing, to 51 units. He said that these resources were changing and shaping their offers consistent with what the ISO expected based on the gas trading day. He said that he was pleased to see the functionality being used in the markets, which he indicated helped to improve efficient price formation.

Focusing more specifically on negative pricing, he reported that, in December, there were 20 hours of negative pricing in the Day-Ahead Energy Market and 43 hours of negative pricing in the Real-Time Energy Market, which he attributed to resource owners becoming more familiar with the functioning of the EMOF provisions. He explained generally how prices were being formed behind some constraints, especially in Maine. He explained that, with export constraints, like those in certain pockets of Maine, if the units behind the export constraint do not provide the ISO with any range of dispatchability, congestion behind those constraints would be much higher. To alleviate the congestion, especially in the Day-Ahead Energy Market, the ISO must re-dispatch the system outside of the supply pocket. He reported that, in two instances, prices in the load pocket were between $-300 and $-900, which indicated that the costs of dispatching the system were much greater outside of that pocket. He stated that the size of negative prices would be moderated by increased dispatchability offered by resources into the Day-Ahead Energy Market. He offered to provide additional detail in a follow-up session, which was requested by members.

Members asked clarifying questions. A member asked why on January 2 there were negative prices around $-1,600. Dr. Chadalavada committed the ISO to review that and to report its findings at the February meeting. On a chart reflecting dispatchable versus non-dispatchable generation, a member expressed surprise that dispatchable generation did not increase dramatically with the introduction of the EMOF provisions. Dr. Chadalavada responded that the report on dispatchable versus non-dispatchable generation depended, in part, on the level of loads during the reporting period, and he was uncertain as to whether the relatively light loads in December accounted for the larger percentage of non-dispatchable units providing energy. He said that experiences in January and February would provide additional insights as to whether the EMOF provisions would increase the percentage of dispatchable versus non-dispatchable generation.

A member questioned the accuracy of the chart reflecting weather normalized summer and winter peak loads. Dr. Chadalavada explained that the referenced chart reflected the forecasted actual summer peak, not the weather normalized summer peak. He reported that the 2015 weather normalized summer peak was expected to be 27,970 MW and committed to have the chart updated in the next report.

LITIGATION REPORT

Mr. Doot referred the Committee to the February 3 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted the numerous complaint proceedings that were resulting in many pleadings and requests of the FERC. He reported that the FERC had issued an order accepting the ICR values for the FCA9 CCP. He said that the order reflected the FERC's expectation that the ISO would address the impact of distributed generation forecasts on future ICRs, and that expectation had been discussed during the business planning session the prior day. He reported that Mr. Eric Runge, NEPOOL Counsel, will provide a more complete summary of that order to the Reliability Committee. In response to a member's inquiry, Mr. Doot indicated that NEPOOL Counsel's summary would identify for the Reliability Committee the misinterpretation of NEPOOL's position in the FERC order. Specifically, Mr. Doot explained that FERC summarized NEPOOL's position as a protest, which it had not been, and one that substantively opposed the ICR because it did not include a reduction to reflect the recent distributed generation forecasts. NEPOOL's pleading explained that NEPOOL did not support the ICR values, and requested that future ICR values account for a distributed generation forecast, but did not otherwise take a substantive position on the ICR values. He said that this distinction would also be conveyed in the order summary.

Members were encouraged to contact NEPOOL Counsel with comments or questions on any of the reported matters.

COMMITTEE REPORTS

For the Transmission Committee, Mr. Jose Rotger reported that the Elective Transmission Upgrade (ETU) reform-related Tariff changes would be voted on January 20. Mr. Ken Dell Orto reported that the next Budget & Finance Subcommittee meeting was scheduled for January 22.

Mr. Doot reported that, at the business planning meeting the day before, the large number of Working Groups, Task Forces, and Subcommittees had been a topic of discussion. He said that ISO and NEPOOL Counsel had committed to work together to identify and assemble the mission statements/charters for the various working groups, task forces and subcommittees, including their reporting structures. The plan was for this information to be assembled and reported so that everyone could gain a better understanding of the stakeholder efforts in New England.

OTHER BUSINESS

Mr. Doot reported that the next Participants Committee meeting was scheduled for February 6, 2015 at The Colonnade Hotel, with the discounted room block open for reservations until February 3. He encouraged all members to look for the 2015 Work Plan at the end of

January and to review that Plan for a better understanding of the planned priorities and work effort and for discussion at the February meeting.

There being no further business, the meeting adjourned at 10:45 a.m.

Respectfully submitted,

David T. Doot, Secretary

MEMBERS AND ALTERNATES PARTICIPATING IN JANUARY 9, 2015 PARTICIPANTS COMMITTEE TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
American PowerNet Management	Supplier			Mary H. Smith
Ashburnham Municipal Light Plant	Publicly Owned		Gary Will	
Associated Industries of Massachusetts	End User			Roger Borghesani
Boylston Municipal Light Department	Publicly Owned		Gary Will	
BP Energy Company	Supplier			Nancy Chafetz
Brookfield Energy Marketing/Cross-Sound Cable	Supplier	Aleksandar Mitreski		
Calpine Energy Services, LP	Supplier	John Flumerfelt	Brett Kruse	
Central Maine Power Company	Transmission	Eric N. Stinneford		
Chicopee Municipal Lighting Plant	Publicly Owned		Gary Will	
Conn. Municipal Electric Energy Cooperative	Publicly Owned	Brian Forshaw		
Conservation Services Group	AR			Doug Hurley
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
Cross Sound Cable	Supplier	Jose Rotger		
Dominion Energy Marketing, Inc.	Generation	Ronald Hart		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade	Supplier			William Fowler
Emera Maine	Transmission	Jeffrey A. Jones	Stacy Dimou	
Energy America, LLC	Supplier			Nancy Chafetz
EnerNOC, Inc.	AR	Herb Healy		
Entergy Nuclear Power Marketing LLC	Generation		Ken Dell Orto	
EquiPower Resources Management, LLC	Generation		William Fowler	
Essential Power, LLC	Generation	M.Q. Riding	William Fowler	
Exelon Generation Company	Supplier		William Fowler	
First Wind Energy Marketing	AR	John Keene		
Galt Power, Inc.	Supplier	Nancy Chafetz		
GDF SUEZ Energy Marketing NA, Inc.	Generation	Thomas Kaslow		
Generation Group Member	Generation		Abby Krich	
Granite Ridge Energy, LLC	Supplier		William Fowler	
Groton Electric Light Department	Publicly Owned		Gary Will	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault	Robert Stein	
Harvard Dedicated Energy Ltd	End User	Mary H. Smith		
High Liner Foods (USA)	End User		William P. Short III	
Holden Municipal Light Department	Publicly Owned		Gary Will	
Holyoke Gas & Electric Department	Publicly Owned			Gary Will
Hull Municipal Lighting Plant	Publicly Owned		Gary Will	
Industrial Energy Consumer Group	End User	Donald J. Sipe		
Ipswich Municipal Light Department	Publicly Owned		Gary Will	
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		
Maine Skiing, Inc.	End User	Donald J. Sipe		
Mansfield Municipal Electric Department	Publicly Owned		Gary Will	
Marblehead Municipal Light Department	Publicly Owned		Gary Will	
Massachusetts Attorney General's Office	End User	Fred Plett	Christina Belew	
Mass. Municipal Wholesale Electric Company	Publicly Owned	Gary Will		
Middleborough Gas and Electric Department	Publicly Owned		Gary Will	
New England Power Company	Transmission	Tim Brennan	Tim Martin	
New Hampshire Electric Cooperative, Inc.	Publicly Owned	Steve Kaminski		
New Hampshire Office of Consumer Advocate	End User	Paul R. Peterson	Sarah Jackson	

ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN
JANUARY 9, 2015 PARTICIPANTS COMMITTEE TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Noble Americas Gas & Power Corp.	Supplier		Becky Merola	
NRG Power Marketing, Inc.	Generation	Dave Cavanaugh		
NU/NSTAR	Transmission	James Daly	Calvin A. Bowie	Joe Staszowski
Paxton Municipal Light Department	Publicly Owned		Gary Will	
Peabody Municipal Light Plant	Publicly Owned		Gary Will	
PowerOptions, Inc.	End User	Cindy Arcate		
Princeton Municipal Light Department	Publicly Owned		Gary Will	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Repsol Energy North America	Gas Industry Part.	Sam Moreton		
Russell Municipal Light Dept	Publicly Owned		Gary Will	
Shrewsbury Electric & Cable Operations	Publicly Owned		Gary Will	
Small LR Group Member	AR	Doug Hurley		
Small RG Group Member	AR	Erik Abend		
South Hadley Electric Light Department	Publicly Owned		Gary Will	
Sterling Municipal Electric Light Department	Publicly Owned		Gary Will	
Tangent Energy Solutions, Inc.	Provisional Group	Brad Swalwell		
Templeton Municipal Lighting Plant	Publicly Owned		Gary Will	
The Energy Consortium	End User	Roger Borghesani	Mary Smith	
The United Illuminating Company	Transmission	Christian Bilcheck		
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		Gary Will	
West Boylston Municipal Lighting Plant	Publicly Owned		Gary Will	
Westfield Gas & Electric Department	Publicly Owned		Gary Will	