FINAL

A meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Friday, August 2, 2013 at the Radisson Hotel, 700 Elm Street, Manchester, NH, pursuant to notice duly given. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates attending the meeting.

Mr. Calvin Bowie, Chair, presided and Mr. David Doot, Secretary, recorded. Mr. Bowie welcomed the members, alternates and guests who were present.

CONSENT AGENDA

Mr. Doot referred the Committee to the Consent Agenda that was circulated in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved.

ORDERS 764 AND 764-A REVISIONS TO OATT SCHEDULE 22

Mr. Jose Rotger, Transmission Committee Vice-Chair, referred the Committee to the materials posted in advance of the meeting regarding revisions to Schedule 22 of the ISO Open Access Transmission Tariff (OATT) (the Large Generator Interconnection Procedures). He explained that minor changes were designed to comply with FERC Orders 764 and 764-A and related to the integration of Variable Energy Resources (VERs). Specifically, the revisions added a new Section 8.4 to the *pro forma* Large Generator Interconnection Agreement setting forth the obligation on the part of VERs (referred to as Intermittent Power Resources) to provide certain meteorological and forced outage data to the ISO. He reported that the Transmission Committee unanimously recommended Participants Committee support for the revisions at its July 22, 2013 meeting and the recommendation would have been on the Consent Agenda but for the timing of the Transmission Committee vote.

The following motion was duly made, seconded, and unanimously approved without any discussion:

> RESOLVED, that the Participants Committee supports the proposed revisions to Schedule 22 of the ISO-NE OATT, as recommended by the Transmission Committee at its July 22, 2013 meeting, together with such further non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.

ORDER 755-RELATED REGULATION MARKET COMPLIANCE REVISIONS

Ms. Allison DiGrande, Markets Committee Chair, referred the Committee to materials posted in advance of the meeting regarding revisions to Market Rule 1 to allow regulation providers to incorporate inter-temporal opportunity costs into their bids, proposed in response to the FERC's June 20, 2013 order in Docket No. ER12-1643 (the June 20 Order). She explained that, in the June 20 Order, the FERC conditionally approved revised Regulation Market design changes that were jointly filed by the ISO and NEPOOL to comply with Order 755, subject to the ISO submitting a further compliance filing by August 5, 2013. That compliance filing would include additional Tariff modifications to provide explicitly that a resource's Regulation Capacity Offer may include verifiable inter-temporal opportunity costs. She reported that the Markets Committee voted unanimously to recommend Participants Committee support for these Tariff revisions at its July 25 meeting and, but for the timing of the Markets Committee vote, this recommendation would have been on the Consent Agenda.

The following motion was duly made, seconded, and unanimously approved, without discussion:

> RESOLVED, that the Participants Committee supports the revisions to Market Rule 1 to allow regulation providers to incorporate inter-temporal opportunity costs into their bids as recommended by the Markets Committee at it July 25, 2013 meeting and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

REPORT OF THE ISO CHIEF EXECUTIVE OFFICER

Mr. Gordon van Welie, ISO Chief Executive Officer, referred the Committee to the summary of the ISO Board and Board Committee meetings that had occurred since the Summer Meeting, which had been posted in advance of the meeting. He expressed appreciation to NEPOOL, NESCOE, and NECPUC for their support on the request for delayed effectiveness of the region's revised Order 755-related Regulation Market design changes, which the FERC had recently granted to and including October 1, 2014.

Responding to a question concerning a Boston Globe article that morning, Mr. van Welie reported that the Globe sought details concerning the recent Energy Information Agency (EIA) report showing price separation in the gas markets in New England from the rest of the country. He said that study showed that gas prices had roughly doubled since 2012, which was directly effecting wholesale electricity prices. He expected the price separation to continue until additional gas pipeline capacity into New England was built (and could take advantage of available shale gas). In response to another member's question, he committed to have ISO representatives explain to the Markets Committee how capacity pricing would work in the NEMA/Boston area during the transition from floor price to the latest auction clearing price.

REPORT OF THE ISO CHIEF OPERATING OFFICER

Dr. Vamsi Chadalavada, ISO Chief Operations Officer, referred the Committee to the August COO Report, which had been posted in advance of the meeting on both the NEPOOL and ISO websites. He explained that the report reflected data through July 26, 2013. Summarizing that data, he reported that in July: (i) natural gas prices were 7.6% higher and oil prices were 1.7% lower higher than June 2013 average values; (ii) Real-Time Hub LMPs were 66% higher than June 2013 averages; (iii) Net Commitment Period Compensation (NCPC), totaling \$20.7 million, was \$10.9 million higher than June 2013 NCPC; (iv) first contingency payments totaled $11.1 million, which was $6.2 million higher than June's first contingency payments; (v) second contingency payments totaled $1.2 million, which was $2.1 million lower than the $3.3 million in June; and (vi) voltage support payments totaled $6.9 million, up $5.6 million from June. He reported that, based on the 50/50 and 90/10 load forecasts, the lowest Summer Operable Capacity Margin was projected for the week beginning September 7 and the lowest Fall Operable Capacity Margin was projected for the week beginning September 21.

Dr. Chadalavada went on to report that the ISO had made a compliance filing with the FERC on July 30 indicating a schedule to target the ninth Forward Capacity Auction (FCA9) for changes related to the development of capacity zones. He said that a draft of the most recent Regional System Plan (RSP 13) had been distributed to stakeholders for comment and would be reviewed at the August 13, 2013 Planning Advisory Committee meeting.

Reviewing operations, Dr. Chadalavada reported a disturbance on July 3 in Quebec caused by forest fires in the James Bay area, that ultimately impacted the New England bulk power system as follows:

- 4 transmission lines tripped;
- Approximately 2,900 MW of Quebec generation rejected Special Protection Scheme;
- Approximately 3,500 MW of Quebec load tripped;
- Approximately 3,370 MW of exports to NYISO, ISO, NBSO, and IESO tripped; and
- Approximately 1,750 MW of imports from HQ to New England were interrupted.

He reported that New England recovered from the first loss in under 11 minutes without System Operating Limit or Interregional Operating Limit violations. Dr. Chadalavada reported that TransÉnergie was working with NERC and NPCC to perform an event analysis, with no set timeline for completion. He committed the ISO to make that analysis available upon receipt. He explained also that, based on the July event, the ISO was working with TransÉnergie to improve communications.

Turning to operations during the July 14-20, 2013 heat wave, Dr. Chadalavada stated that the ISO had preparatory meetings prior to, and during, the heat wave with the NYISO, HQ, NBSO, IESO, PJM, MISO Reliability Coordinators, Master Local Control Areas, and gas pipeline operators. He referred the Committee to slides summarizing events during the heat wave, including:

- The postponement or cancellation of all transmission work and generation outages and reductions that could have been postponed or cancelled to ensure operations during the heat wave.
- The July 15 implementation of Master/Local Control Center Procedure 2 (M/LCC 2), with forecasted tight operating reserves throughout the heat wave.
- Weather deviations from that forecasted that impacted load forecast accuracy, particularly on July 18 when temperatures dropped significantly along the coast due to an afternoon sea breeze. Dr. Chadalavada indicated that loads during such times would also be materially impacted by increased humidity.
- Patterns of expected generation reductions, sporadic unit trips, and unpredictable load produced the greatest degree of uncertainty.
- The implementation of OP4 on July 19 in response to generator reductions and transmission constraints:
    - Operating deficiency of 449 MW forecasted based on the load forecast of 27,850;
    - Peak hour generator reductions and outages totaled 4,611 MW;
    - Forecasted temperature in Boston and Hartford was 99°F;
    - Actual temperatures in Boston were as forecasted; actual temperatures in Hartford were slightly lower;
    - Scheduled net imports for the peak hour expected to be 1,718 MW; and
    - Actual net imports scheduled totaled 2,677 MW.

Members expressed appreciation to the ISO for its efforts to keep the System operating and for maintaining reliability. A member suggested that some of the OP4 actions might be unnecessary were there more incentives to clear Day-Ahead, with which Dr. Chadalavada concurred. In response to questions concerning generation performance, Dr. Chadalavada summarized that there were units that were online that had to come offline, units that were not able to start when scheduled, units that had to reduce output because of condenser issues and discharge issues, and units that experienced forced outages, especially older units seldom called to operate.

Focusing on demand response (DR), Dr. Chadalavada noted that several hundred megawatts of DR cleared in the auction relevant to this delivery period. He said that DR Resources in Maine were not dispatched, since OP4 had not been declared in Maine. The Central Maine Power (CMP) member reported on significant reductions in load on the CMP System experienced during each day of the heat wave, whether for price responsive reasons or other reasons. Dr. Chadalavada requested to review that data, which he hoped would help the ISO with its load profile reconstitution.

A DR representative stated that July performance underscored the need for a diversity of resources and more DR in the future. Several members questioned whether the region's Installed Capacity Requirement (ICR) reflected appropriate assumptions. Dr. Chadalavada responded that the forced outages over the peak hour were greater than assumed in the ICR. The ISO intended to relook at forced outages rates and tie benefits in the evaluation of System reserves and generation profiles.

On behalf of NEPOOL, Mr. Bowie expressed appreciation to the ISO and to the Control Room operators for their efforts during the heat wave.

IMM QUARTERLY MARKETS REPORT: Q2 2013

Mr. David LaPlante, ISO Vice President Internal Market Monitoring (IMM), referred the Committee to a presentation summarizing highlights from the IMM Quarterly Markets Report for the second quarter (Q2) of 2013, which had been posted in advance of the meeting. He reviewed that Q2 2013 was similar to Q2 2012, adding prices and uplift were lower than the first quarter of 2013. He highlighted that Q2 2013 gas prices averaged $4.64/MMBtu for the quarter, as compared to $2.81/MMBtu for Q2 2012. Consistent with past trends, Day-Ahead prices and Real-Time prices were nearly identical.

Mr. LaPlante stated that the ISO conducted analysis reflecting changes in available capacity from the Day-Ahead Market to Real-Time, with total capacity calculated based on offered EcoMax values and redeclarations made during the operating day. He referred the Committee to charts reflecting that analysis from January 2010 to June 2013 and noted the following key points:

- Available capacity reductions were highest in the early morning hours.
- The amount of capacity reductions were highest among gas-fired resources, which influenced intra-day trends in other capacity reductions.
- More available capacity reductions occurred between the Day-Ahead to Re-Offer interval than the Re-Offer to Real-Time interval.

In response to questions, Mr. LaPlante agreed that the difference in capacity reductions could be explained in part by a 2011 change in the Market Rules that required temperature-effected resources to adjust their EcoMin to their High Operating Limit in Real-Time as they were occurring. He also indicated that the results did not reflect significant experience with recent changes advancing Day-Ahead Energy Market deadlines, and the ISO will watch this issue over the next year for change and will report and respond accordingly.

Mr. LaPlante stated that an article regarding market performance metrics was included in the Quarterly Report that would be circulated the following week, and requested Committee feedback on that article. He indicated that price outcomes in the ISO-administered energy market were consistent with those expected of a competitive market.

Concluding his presentation, Mr. LaPlante reviewed charts reflecting virtual transactions, NCPC payments, and supplemental commitments, and other market outcomes, reporting that:

- Virtual transactions continued to be at much lower levels than they were at their peak. There was still convergence between the Day-Ahead and Real-Time prices, so the virtual transaction reduction did not seem to be significantly harming the markets but was a trend the IMM would continue to monitor.

- After the substantial jump in Q1 2013, NCPC payments were in-line with 2012, but were expected to jump again in Q3 2013, based on July conditions.
- The ISO had not made supplemental commitments in the majority of hours.
- As a result of an increase in the Ten-Minute Non Spinning Reserve requirement, the Summer 2013 Forward Reserve Market auction clearing price was $5,946/MW-month, as compared to $3,450/MW-month in the Summer 2012 auction and $3,301/MW-month in the Winter 2013 auction.

FCA IMPORT CAPACITY QUALIFICATION CHANGES TO MANUAL M-20

Ms. DiGrande referred the Committee to the materials posted in advance of the meeting regarding revisions to Manual M-20, in which the ISO had proposed to provide additional detail on the Forward Capacity Auction qualification process for Import Capacity Resources (Import Capacity Qualification Changes). She summarized the Markets Committee's consideration of the changes, and she said that during the qualification process for the seventh Forward Capacity Auction (FCA7), the ISO submitted additional questions to Market Participants that were seeking to qualify Import Capacity Resources. That additional information was designed to establish that external resources seeking capacity obligations would be deliverable to the New England Control Area. She explained that, based on the answers the ISO received to those questions, certain Import Capacity Resources were not qualified internally for FCA7 based on an insufficient demonstration as to how the Resources would be deliverable through New York to the New England Control Area for the 2016-2017 Capacity Commitment Period. In its presentation to the Markets Committee, the ISO explained that the Import Capacity Resource qualification questionnaire had been posted on the ISO website and clarified that information from that questionnaire would be collected in order to determine whether to qualify Import Capacity Resources. The ISO proposed to update Manual M-20 to include a link to the qualification questionnaire and to include a reference to the Market Rule provisions (Section III.13.1.1.2.7) that permit the ISO and the bidder of new Resources to consult. At its July 10-11, 2013 meeting, the Markets Committee considered and failed to support the ISO's proposed Import Capacity Qualification Changes with a 54.8% Vote in favor.

She went on to report that, based on stakeholder feedback following that Markets Committee meeting, the ISO made non-substantive revisions to insert the questionnaire as Attachment L to Manual M-20, rather than to include a link to the questionnaire, and to remove from the questions specific references to FCA8.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to Manual M-20 to provide additional detail for Import Capacity Resource qualification as proposed by the ISO and as circulated to this Committee in advance of this meeting (including the additional revisions proposed by the ISO since the Markets Committee vote), together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

The Committee members then asked clarifying questions. In response to members' questions as to why any change was needed, Mr. Mark Karl, ISO Senior Director Resource Adequacy, stated the changes were to provide additional clarity as to the types of questions to be asked in furtherance of the ISO's obligation to ensure that Resources that qualified, whether internal or external, could be used by the System when needed. He added that the ISO, as permitted under the Market Rules, had the authority, and would, if necessary, ask additional questions.

Members expressed appreciation to the ISO for agreeing to incorporate the questionnaire into the Manual. Others, who had previously imported capacity, indicated that they opposed the proposed Manual Changes arguing that these changes reflected modified standards being imposed by the ISO that should be filed and included in the ISO Tariff.

Mr. Doot reminded the Committee that Manuals are not filed with the FERC. Manual changes, however, can only be made after NEPOOL has an opportunity to consider them in the stakeholder process. Some questioned whether the ISO had a compliance obligation under the

FCA7 order relating to this matter. Mr. Doot responded that during the FCA7 qualification process, the ISO represented to the FERC that it would clarify the qualification process and discuss those clarifications in the stakeholder process. The FERC acknowledged and recognized that commitment, but in its Order did not require that there be a subsequent filing by the ISO. Mr. Kevin Flynn, ISO Counsel, confirmed the ISO's view that there was no compliance filing required by the order. Responding to member concerns about not knowing what the ISO would do with the data that it was requesting, Mr. Doot acknowledged the concerns but clarified that the requested vote was to support the proposed Manual Changes without regard to whether further standards should be included in the Market Rules or Manuals.

In final comments, Mr. Karl explained that because the Market Rules define imports as new every year, new resources must be re-qualified every year, and Import Capacity Resources would have to provide the information requested. He said that imports, unlike internal generators, could elect whether or not to participate in each auction without seeking to delist. Further, he noted that the ISO did not run, or plan, the New York System, but needed information demonstrating deliverability in order to qualify imports. He stated the ISO had not required to date that external Resources present transmission studies to support this deliverability, and would continue to consider less intrusive ways for those Resources to satisfy deliverability requirements.

The Committee then considered the motion, which failed to pass with a 47.95% Vote in favor (Generation – 0%; Transmission – 17.08%; Supplier – 7.36%; AR – 0%; Publicly Owned Entity – 16.64%; and End User – 6.87%). (See Vote 1 on Attachment 2).

FCM SHORTAGE EVENT TRIGGER REVISIONS

Ms. DiGrande referred the Committee to the materials posted in advance of the meeting regarding revisions to Market Rule 1 to modify the Shortage Event triggers in the Forward

Capacity Market (Shortage Event Trigger Proposal), which as then in effect defined a Shortage Event to occur when there was thirty contiguous minutes of Ten-Minute Non-Spinning Reserve (TMNSR) Reserve Constraint Penalty Factors (RCPF) imposed. She explained that the ISO proposed that, until June 1, 2017, the definition of Shortage Event would be expanded to include an event in any Capacity Zone following thirty contiguous minutes of RCPF activation for system-wide Thirty-Minute Operating Reserves (TMOR) while Operating Procedure No. 4 (OP4) Action 2 had also been implemented in that Capacity Zone. For import-constrained Capacity Zones, a Shortage Event would occur if there were any Action 2 under OP4, or an OP7 event that was declared for the entire zone for thirty or more contiguous minutes, and that was not also declared for the entire Rest-of-Pool Capacity Zone. Beginning June 1, 2017, once Real-Time Demand Resources would be dispatched according to their energy offer and would no longer be dispatched under OP4 Action 2, the TMOR Shortage Event trigger would cease to require any activation of OP4. Similarly, the Shortage Event Trigger Proposal also specified that, as of June 1, 2017, the definition of a Shortage Event for an import-constrained zone will be thirty or more contiguous minutes of RCPF activation for local TMOR.

She reviewed two amendments offered and considered by the Markets Committee:

(1) a NextEra motion to amend the main motion (NextEra Amendment) so as to maintain the current definition of a FCM Shortage Event until June 1, 2017, which failed at the Markets Committee with a 59.94% Vote in favor; and

(2) a PSEG motion to amend the main motion (PSEG Amendment), so as to make implementation of the modified Shortage Event triggers that would go into effect beginning June 1, 2017 contingent upon the eligibility of Demand Resources to provide Operating Reserves, which passed at the Markets Committee with a 72.25% Vote in favor. The amended main motion, however, had then failed with a 28.5% Vote in favor, and the ISO had decided not to include PSEG's proposed modifications in the Markets Committee vote on its proposal.

Ms. DiGrande summarized developments that had occurred following the Markets Committee meeting. Noting PSEG's concern that DR Resources be eligible to provide Operating Reserve before the Proposal took effect (ensuring all capacity Resources would be fully utilized before expanding the risk of penalties for non-performance), she indicated that the ISO would make clear in the FERC filing that, if for some reason the ISO's June 1, 2017 target for having DR in the reserve market was delayed, the ISO would suggest further changes to address the Market Rules. She reported that, in light of the ISO's offer to include language in its FERC filing, PSEG would not present its Amendment for Participants Committee consideration.

Ms. DiGrande also reviewed a subsequent clarification to the language reviewed by the Markets Committee regarding TMOR triggers in local areas. Specifically, rather than identifying the trigger as occurring "when the price is at the $250 RCPF", the RCPF in that triggering condition would instead state "when the RCPFs are triggered for TMOR". No members objected to including the clarification as part of the main motion.

The following main motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to Market Rule 1 to modify the FCM Shortage Event triggers as recommended by the Markets Committee at its July 10-11, 2013 meeting and as circulated to this Committee in advance of this meeting, together with those changes agreed to by the Participants Committee at this meeting and such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Members then commented and asked clarifying questions on the ISO Proposal. Numerous members expressed concern with the impact of the change on the terms of capacity transactions after those transactions had already been committed. They explained that their concerns related not solely to Capacity Supply Obligations (CSOs) obtained in FCAs, but also to the substantial amount of CSOs transferred in annual reconfiguration auctions and bilaterals at significantly different prices than the initial FCA. They explained that, when Resource owners analyzed their participation in the FCM, they relied on the Market Rules as they were then in effect and administered. They went on to explain that, even if the Shortage Event trigger definition in the Tariff was considered ambiguous, there was a course of dealing over several years that established what Shortage Event meant and a common understanding of what would trigger a Shortage Event. Resources participated in the FCM with that reasonable understanding of the risks around the trigger. To materially change such risks without an opportunity to amend an offer reflecting that changed risk would be unfair.

Mr. Andrew Gillespie of the ISO, in response to a question about the impact of the Shortage Event definition change on DR dispatch, explained that the trigger would not affect how such Resources would be dispatched due to the condition that established Shortage Events based on a reserve deficiency of thirty or more minutes.

Other members argued in favor of the ISO Proposal, saying it was reasonable for Resources that were being paid for capacity to expect that their performance would be tested once or twice a year as a condition to their capacity payments. They expressed their view that the ISO Proposal merely ensured that Shortage Events would occur at a frequency that should have been reasonably expected. They suggested that the fact that there was no Shortage Event on July 19 demonstrated that the existing provisions were not operating as they should have been reasonably anticipated to operate. By analogy, some explained that energy efficiency Resources earn a large portion of their revenues for the year from, and are tested for seven hours for, their capacity payments. The ISO-proposed changes, they indicated, would bring comparability to generation Resources with respect to the number of tests.

NHPUC Commissioner Michael Harrington opined that the July 19 event confirmed that the definition of a Shortage Event needed to be changed. He questioned, however, the fairness of changing that definition as it applied to existing commitments that were based on the then current Market Rules. He referred back to the discussions concerning allocation of the Winter operation costs, where the ISO concluded it was unfair to impose additional costs on existing transactions, and suggested similar rational suggested application of the definition change only for new transactions.

In response to these observations, Dr. Robert Ethier explained that unlike the Winter Program that was a new program that was not expected and was not previously part of the Market Rules, the Shortage Event change was intended to fix an existing Market Rule that was not functioning correctly. He noted that Market Participants would almost always be impacted when Market Rules were adjusted to bring results into line with intended outcomes, sometimes to their advantage, but sometimes to their disadvantage.

Some Market Participants disagreed with ISO's suggestion that the change was to bring the Market Rules in line with intended outcomes. For example, the Footprint Power representative explained, that in its transaction to acquire the Salem Units, Footprint considered the probability of a Shortage Event based on the existing definition and its agreement to take on the remaining CSOs reflected that analysis. Others concurred that the definition change would not restore expectations but, rather, would change expectations, and should be applied only to new transactions.

The NESCOE representative stated that the New England States viewed Shortage Event triggers as an important component of FCM and favored appropriate performance incentives. NESCOE viewed the recent heat wave, and July 19 in particular, as providing anecdotal evidence that the System needed capacity at times when the current triggering conditions had not been met. He suggested that updating the triggering conditions was necessary to fix a broken provision in the Market Rules. The States agreed that "a deal is a deal", but the deal never was that there would never be a Shortage Event. He stated that the proposed Market Rule changes were expected to trigger only once or twice a year, which seemed reasonably consistent with expectations. Accordingly, the States supported the ISO Proposal.

In response to NESCOE's observations, opponents of the ISO Proposal disagreed with the notion that the Shortage Event trigger was to test performance of Capacity Resources. That goal was accomplished through adoption of specific performance incentives, not through increasing the number of Shortage Events. Other Market Participants reinforced the view that the definition of Shortage Events needed to be fixed, but that such a fix should be applied only to new transactions.

NextEra Amendment

The NextEra representative offered the NextEra Amendment, which was posted in advance of the meeting, to amend the main motion so as to maintain the current definition of a FCM Shortage Event until June 1, 2017. The motion to amend was seconded and discussed, with many of the same observations made concerning the appropriateness of limiting such changes solely to new transactions.

On behalf of the ISO, Dr. Ethier stated the ISO did not support the NextEra Amendment. He explained his view that the ISO had acted to prevent short-term harm based on flawed rules. He reminded the Committee that the ISO previously changed the trigger in 2010 to prevent too many Shortage Events, and was acting to fix the trigger that had resulted in too few Shortage Events.

The motion to amend was voted and approved with a 78.64% Vote in favor (Generation – 17.17%; Transmission – 5.72%; Supplier – 17.17%; Alternative Resources – 8.06%; Publicly Owned Entity – 17.17%; and End User – 13.35%). (See Vote 2 on Attachment 2).

Vote on the Once-Amended Main Motion

The once-amended main motion (as amended by the NextEra Amendment) was then voted and approved with a 77.90% Vote in favor (Generation – 17.17%; Transmission – 5.72%; Supplier – 17.17%; Alternative Resources – 8.06%; Publicly Owned Entity – 16.57%; and End User – 13.21%). (See Vote 3 on Attachment 2).

Vote on the ISO Proposal

At the request of the ISO, the Committee considered and failed to approve the unamended main motion with a 30.99% Vote in favor (Generation – 0%; Transmission –

17.17%; Supplier – 0%; Alternative Resources – 8.29%; Publicly Owned Entity – 1.72%; and End User – 3.81%). (See Vote 4 on Attachment 2).

MR 1 APPENDIX A COST RECOVERY COMPLIANCE CHANGES

Ms. DiGrande referred the Committee to the materials posted in advance of the meeting regarding revisions to Appendix A to Market Rule 1 to allow Market Participants to submit a Section 205 filing for cost recovery. As background, she reviewed that Dominion had filed a request with the FERC on April 15, 2013, since approved by the FERC on June 14, to recover additional fuel costs incurred with the dispatch of its Manchester Street Units on February 10, 2013, as well as reasonable, related regulatory costs. She explained that Dominion also requested the FERC to direct the ISO to implement certain Market Rule changes to minimize the risk that generators in the future would be unable to recover their full incremental costs for operating their units when requested by the ISO to provide a critical reliability service. She said that the ISO and NEPOOL opposed Dominion's request for an order to change the Market Rules absent a request for such changes in the stakeholder process and a properly filed complaint proceeding if that stakeholder process did not produce the desired result. In its June 14 order, the FERC granted Dominion's fuel cost recovery request and conditionally accepted Dominion's request for regulatory cost recovery. The FERC also instituted a Section 206 proceeding (EL13-72), directing the ISO to submit by July 29, 2013 Tariff revisions to Appendix A to allow Market Participants to submit a Section 205 filing for cost recovery when a Resource is dispatched under certain circumstances for reliability reasons. In response to a joint request by NEPOOL and the ISO, without opposition by Dominion, the FERC had extended the compliance filing date to August 13, 2013.

Continuing, Ms. DiGrande explained that, in response to the FERC's directive, the IMM proposed and the Markets Committee recommended for approval, revisions to Appendix A (Cost

Recovery Proposal) that would permit a Section 205 filing when a Resource is committed beyond its Day-Ahead Energy Market schedule when the ISO has declared an Abnormal Systems Conditions Alert (M/LCC 2). In that proposal, an ISO declaration an action of either Operating Procedure No. 4 (action during a capacity deficiency) or Operating Procedure No. 7 (action in an emergency) would also constitute declaration of an Abnormal Systems Conditions Alert for purposes of the cost recovery provision. She reported that the Markets Committee considered and recommended Participants Committee support for the IMM's Cost Recovery Proposal at its July 25, 2013 meeting with a 87.18% Vote in favor. She reported also that there were several amendments proposed at that Markets Committee meeting which were considered but did not pass, that would be raised again at this meeting.

The following motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to Appendix A to Market Rule 1 to allow Market Participants to submit a Section 205 filing for cost recovery when a resource is dispatched under specific circumstances for reliability reasons as recommended by the Markets Committee at it July 25, 2013 meeting and as circulated to this Committee in advance of this meeting, together with any changes agreed to by the Participants Committee at this meeting and such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Calpine/Capital Power Amendment

A motion was offered jointly by Calpine and Capital Power, and was duly made and seconded, to amend the main motion so as to provide an opportunity for gas-fired generators to submit a Section 205 cost recovery filing if a *force majeure* event on the pipeline system serving those generators occurred. The Capital Power representative expressed her view that the FERC was clear in its June 14 order that generators should have the ability to go to the FERC to seek recovery of costs incurred because of extraordinary circumstances. She said that, since that order, a number of generators in Maine experienced the effects of a lightning storm that caused a station outage in Quebec and a *force majeure* interruption on the natural gas pipeline. Those generators already had been scheduled in the Day-Ahead Market and had arranged for fuel to meet that commitment. The pipeline provided notice of the *force majeure* declaration that evening, interrupting delivery of gas to the pipeline serving those generators. To cover their Day-Ahead schedule, those generators were able to acquire gas on a different pipeline but that gas was much more expensive. The current Market Rules provided no ability for those generators to seek recovery of those additional costs. She opined that those circumstances fit in the spirit of what the June 14 order required to be addressed. She requested the right, were this to happen in the future, for impacted generators to go the FERC, consistent with the same format that the ISO was proposing, with a similar Section 205 filing, similar documentation that would need to be prepared and reviewed, and similar cost allocation and provisions. She acknowledged generators' responsibility to manage and price their fuel risk, but advocated for the opportunity to request FERC-approved cost recovery in very narrow circumstances, a pipeline *force majeure* declaration, that was a development incapable, practically, of being foreseen, managed, or priced into the market. She added that, with intra-day offers, Real-Time prices resulting from the *force majeure* event might be reflected in the market. In this case though, with the notice coming out late at night, and not having hourly offers in place, there was no way to reflect those costs in the market.

Members then asked clarifying questions and commented on the motion to amend. Those opposing the change argued that the risks and costs identified were properly borne by Market Participants supplying power and not by captive customers. Continuing, the argument was made that the risk of *force majeure* events were properly negotiated between a generator and the purchaser of power from that generator, and generators could enter into arrangements to hedge themselves against *force majeure* events with alternative suppliers or with back-up fuel. In response to questions, the proponents of the motion to amend confirmed that only incremental costs from the *force majeure* declaration would properly be sought. Further, they confirmed that their concerns would largely, but not entirely, go away once hourly re-offers were permitted. The Capital Power representative noted that a commitment was made at the Markets Committee to reevaluate these provisions once hourly offers were permitted. On behalf of the ISO, Mr. LaPlante confirmed that commitment.

Members speaking in support of the amendment emphasized the desire to better align the incentives of Resource owners with the ISO's desire for them to follow dispatch and provide the requested energy. They suggested that *force majeure* events were extraordinary and presumably infrequent events and certainly more like an OP7 declaration. Therefore, they argued, it was appropriate and very limited in application. Others expressed concerns with very broad exemptions allowing pursuit of out-of-market recoveries, but indicated their views that the proposed exemption here did not raise such concerns. They suggested it would be improbable that generators would adjust their bids down because they thought a *force majeure* event might happen and the FERC would allow recovery of additional costs. They argued this change would not raise a price formation issue, but rather was an extremely rare situation where it would be appropriate to permit generators to seek out-of-market cost recovery when they were called on for reliability.

Mr. LaPlante repeated that the ISO did not support the Calpine/Capital Power Amendment. He indicated that, although the ISO shared some of the concerns prompting the amendment from a market design perspective, it was the ISO's view from a pure compliance perspective that the order required only that generators be permitted to seek cost recovery for dispatches above Day-Ahead Energy Market quantities.

In final comments, the proponents of the motion to amend reinforced their view that their concern was not a price formation issue, that they had been appropriately sensitive to concerns about the mechanism, and intended that the mechanism be very narrow in its application. Addressing the ISO's opposition on compliance-related procedural grounds, the proponents observed that the change could properly still be put before the FERC as a Section 205 filing related to compliance.

The Committee considered and approved the Calpine/Capital Power motion to amend the main motion with a 60.76% Vote in favor (Generation – 17.17%; Transmission – 0%; Supplier – 12.37%; Alternative Resources – 5.49%; Publicly Owned Entity – 14.48%; and End User – 11.25%). (See Vote 5 on Attachment 2).

Dominion Amendment 1

The Dominion representative offered a motion to amend the once-amended main motion to include Dominion Amendment 1, as posted in advance of the meeting, so as to revise the proposed Section III.A.15.1 of Appendix A to Market Rule 1 (Filing Right) to provide cost recovery for a Resource any time it was dispatched beyond its Day-Ahead commitment or dispatched out-of-merit when it did not receive a Day-Ahead commitment, and to strike from Tariff provisions the ISO's qualifier of having such opportunity to request recovery only available during either OP4 or Abnormal Systems Conditions Alert. That motion was duly seconded.

Following brief clarifying questions, Mr. LaPlante commented that Dominion Amendment 1 would eliminate a large amount of risk from generators in the market by allowing them to seek cost recovery any time they were dispatched above their Day-Ahead schedule. He opined that the FERC clearly recognized that such a blanket approach would undermine the market, and in the June 14 order, limited cost recovery to critical reliability events. He argued, therefore, that the language the ISO proposed to define critical reliability events was properly compliant with the June 14 FERC order.

The Committee considered and, by a show of hands, failed to approve Dominion Amendment 1.

Dominion Amendment 2

The Dominion representative then offered a second motion to amend the main motion in order to include Dominion Amendment 2, as posted in advance of the meeting, whereby proposed Section III.A.15.1 would be revised so as to provide that, if the ISO conditions fail to capture an event where a Resource is financially harmed because the ISO's trigger for abnormal conditions was not declared, the effected party would still be allowed to seek cost recovery through a Section 205 filing upon a showing to the FERC that it was financially harmed and justified in its actions to respond to the ISO's dispatch request. The Dominion Amendment 2 was duly seconded.

The Committee then asked clarifying questions on Amendment 2. On behalf of the ISO, Mr. LaPlante stated that, in contrast to the ISO Proposal, which was intended to limit the ability of the Resource to file, Dominion Amendment 2 would permit any Resource to go to the FERC at any time and argue that a critical reliability event took place without guidance as to the standard for defining such an event. He stressed the importance of specific and transparent standards, such as those proposed by the ISO.

The Committee considered and failed to approve Dominion Amendment 2 based upon a show of hands.

Vote on the Once-Amended Main Motion

The once-amended main motion (as amended by the Calpine/Capital Power Amendment) was then voted and approved with a 64.70% Vote in favor (Generation – 17.17%; Transmission – 0%; Supplier – 7.63%; Alternative Resources – 14.17%; Publicly Owned Entity – 14.48%; and End User – 11.25%). (See Vote 6 on Attachment 2).

Vote on the ISO Proposal

At the request of the ISO, the Committee considered and failed to approve the unamended main motion (the ISO Proposal) with a 49.50% Vote in favor (Generation – 0%; Transmission – 17.17%; Supplier – 9.54%; Alternative Resources – 14.17%; Publicly Owned Entity – 2.68%; and End User – 5.94%). (See Vote 7 on Attachment 2).

LITIGATION REPORT

Mr. Doot referred the Committee to the Litigation Report that had been posted in advance of the meeting, noting again the high-level of activity. There were no questions on that report.

OTHER BUSINESS

Mr. Doot referred the Committee to the NEPOOL calendar on the NEPOOL website, highlighting upcoming meetings and events. He reminded the Committee that the next regularly scheduled meeting of the Participants Committee was on September 13 at the Colonnade Hotel in Boston. He reminded the members also that the day before the September Participants Committee meeting, there would be a meeting to review the draft 2013 Regional System Plan. He said that the Markets Committee Summer Meeting was scheduled for August 7-9 in Lenox, MA. Looking ahead, he reminded the Committee of the October 4 Participants Committee meeting, noting that the venue was yet-to-be determined and would be posted. He said that the November 8 meeting with the ISO Board would be held at the Hilton Logan Hotel in Boston.

There being no further business, the meeting adjourned at 3:00 p.m.

Respectfully submitted,

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David T. Doot, Secretary

MEMBERS AND ALTERNATES PARTICIPATING IN
AUGUST 2, 2013 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
Ashburnham Municipal Light Plant	Publicly Owned		Gary Will	
Associated Industries of Massachusetts	End User			Roger Borghesani
Bangor Hydro-Electric Company	Transmission		Stacy Dimou (tel)	
Boylston Municipal Light Department	Publicly Owned		Gary Will	
BP Energy Company	Supplier			Nancy Chafetz (tel)
Brookfield Energy Marketing Inc. / CSC	Supplier	Aleksandar Mitreski	Nicolas Bosse	Jose Rotger
Calpine Energy Services, LP	Supplier			Thomas Kaslow
Central Maine Power Company	Transmission	Eric Stinneford (tel)		
Cianbro Companies	End User	Gus Fromuth		
Chicopee Municipal Lighting Plant	Publicly Owned		Gary Will	
Competitive Energy Services, LLC	Supplier			David Norman
Comverge	AR	John Driscoll (tel)		
Concord Municipal Light Plant	Publicly Owned		Gary Will	
Conservation Law Foundation (CLF)	End User		N. Jonathan Peress	
Conservation Services Group (CSG)	AR	Doug Hurley		
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
Corinth Wood Pellets LLC	End User	Gus Fromuth		
CP Energy Marketing (US) Inc. (Capital Power)	Supplier	Michelle Gardner		
DC Energy, LLC	Supplier	Bruce Bleiweis (tel)		
Dominion Energy Marketing, Inc.	Generation	Ronald Hart (tel)		
Dragon Products Company LLC	End User	Gus Fromuth		
Dynegy Marketing and Trade, LLC	Supplier			William Fowler
Elektrisola, Inc.	End User		Gus Fromuth	
Energy America, LLC	Supplier			Nancy Chafetz (tel)
EnerNOC, Inc.	AR	Herb Healy		
Entergy Nuclear Power Marketing, Inc.	Generation		Richard Milici	
Environment Northeast	End User	Mike Henry (tel)		
EP Energy Massachusetts, LLC (Essential Power)	Generation	M.Q. Riding (tel)	William Fowler	
EquiPower Resources Management, LLC	Generation	Jim Ginnetti (tel)	William Fowler	
Exelon New England Holdings / Constellation	Supplier		William Fowler	
Fairchild Semiconductor Corporation	End User	Gus Fromuth		
First Wind Energy Marketing, Inc.	AR	John Keene		Robert Stein
Food City, Inc.	End User	Gus Fromuth		
Galt Power, Inc.	Supplier	Nancy Chafetz (tel)		
GDF SUEZ Energy Marketing North America	Generation	Thomas Kaslow		
Generation Group Member	Generation		Abby Krich	Robert Stein
Granite Ridge/Merrill Lynch	Supplier		William Fowler	
Groton Electric Light Department	Publicly Owned		Gary Will	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guibault (tel)	Robert Stein	
Hardwood Products Company	End User		Gus Fromuth	
Harvard Dedicated Energy Limited	End User	Mary Smith		Roger Borghesani
Hess Corporation	Supplier			Nancy Chafetz (tel)
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Holden Municipal Light Department	Publicly Owned		Gary Will	
Hudson Light and Power Department	Publicly Owned		Gary Will	
Hull Municipal Lighting Plant	Publicly Owned		Gary Will	
Industrial Energy Consumer Group	End User	Donald Sipe (tel)		
Ipswich Municipal Light Department	Publicly Owned		Gary Will	
Kimberly-Clark Corporation	Supplier			Vicki Karandrikas (tel)

MEMBERS AND ALTERNATES PARTICIPATING IN
AUGUST 2, 2013 PARTICIPANTS COMMITTEE MEETING

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
LaBree's Inc.	End User		Gus Fromuth	
Linde Energy Services	Supplier			Vicki Karandrikas (tel)
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		
Maine Public Advocate Office	End User			Sarah Jackson
Maine Skiing, Inc.	End User	Donald Sipe (tel)		
Mansfield Municipal Electric Department	Publicly Owned		Gary Will	
Marblehead Municipal Light Department	Publicly Owned		Gary Will	
Marden's Inc.	End User	Gus Fromuth		
Mass. Attorney General's Office	End User	Fred Plett		
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned	Gary Will		
Middleborough Gas and Electric Department	Publicly Owned		Gary Will	
Middleton Municipal Electric Department	Publicly Owned		Gary Will	
Millennium Power Partners	Generation		Ken Dell Orto	
MoArk, Inc.	End User	Gus Fromuth		
New England Power Company (National Grid)	Transmission	Timothy Brennan (tel)		
New Hampshire Electric Cooperative, Inc.	Publicly Owned		Steve Kaminski	
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson	Sarah Jackson	
NextEra Energy Resources, LLC	Generation	Fernando DaSilva		
NRG Power Marketing, Inc.	Generation			Fernando DaSilva
NU / NSTAR	Transmission	James Daly	Calvin Bowie	Joe Staszowski
PalletOne of Maine	End User	Gus Fromuth		
Paxton Municipal Light Department	Publicly Owned		Gary Will	
Peabody Municipal Light Plant	Publicly Owned		Gary Will	
PowerOptions, Inc.	End User	Cindy Arcate (tel)		
PPL EnergyPlus (PPL)	Supplier		Sharon Weber (tel)	
Praxair, Inc.	End User			Vicki Karandrikas (tel)
Princeton Municipal Light Department	Publicly Owned		Gary Will	
Provisional Group Member – Load Response Sub-Sector	AR			Doug Hurley
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
RJF-Morin Brick LLC	End User			
Rowley Municipal Lighting Plant	Publicly Owned		Gary Will	
Russell Municipal Light Dept	Publicly Owned		Gary Will	
Shipyard Brewing LLC	End User	Gus Fromuth		
Shrewsbury Electric & Cable Operations	Publicly Owned		Gary Will	
Small Distributed Generation Group Member	AR	Doug Hurley		
Small Load Response Group Member	AR	Doug Hurley		
Small Renewable Generation Group Member	AR	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned		Gary Will	
St. Anselm College	End User	Gus Fromuth		
St. Joseph Health Services of Rhode Island	End User		Gus Fromuth	
Sterling Municipal Electric Light Department	Publicly Owned		Gary Will	
Taunton Municipal Lighting Plant	Publicly Owned		Brian Forshaw	
Templeton Municipal Lighting Plant	Publicly Owned		Gary Will	
The Energy Consortium	End User	Roger Borghesani	Mary Smith	
TransCanada Power Marketing Ltd.	Generation		Michael Hachey (tel)	
Union of Concerned Scientists (UCS)	End User	Paul Peterson		
United Illuminating Company, The (UI)	Transmission		Alan Trotta (tel)	
Utility Services Inc.	End User			Paul Peterson

**MEMBERS AND ALTERNATES PARTICIPATING IN
AUGUST 2, 2013 PARTICIPANTS COMMITTEE MEETING**

PARTICIPANT NAME	SECTOR	MEMBER NAME	ALTERNATE NAME	PROXY
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		
Vermont Electric Power Company, Inc. (VELCO)	Transmission	Frank Ettori	Bill Ryan (tel)	
Vermont Energy Investment Corporation	AR		Doug Hurley	
Vermont Public Power Supply Authority (VPPSA)	Publicly Owned	David Mullett		Brian Forshaw
Verso Maine Energy LLC	Generation		Drew Robertson	
Vitol Inc.	Supplier	Joe Wadsworth (tel)		
Wakefield Municipal Gas and Light Department	Publicly Owned		Gary Will	
West Boylston Municipal Lighting Plant	Publicly Owned		Gary Will	
Westerly Hospital	End User		Gus Fromuth	
Westfield Gas & Electric Light Department	Publicly Owned		Gary Will	
ZTECH, LLC	End User		Gus Fromuth	

VOTES TAKEN AT AUGUST 2, 2013 PARTICIPANTS COMMITTEE MEETING

TOTAL

SECTOR	VOTE 1	VOTE 2	VOTE 3	VOTE 4	VOTE 5	VOTE 6	VOTE 7
GENERATION	0.00	17.17	17.17	0.00	17.17	17.17	0.00
TRANSMISSION	17.08	5.72	5.72	17.17	0.00	0.00	17.17
SUPPLIER	7.36	17.17	17.17	0.00	12.37	7.63	9.54
AR	0.00	8.06	8.06	8.29	5.49	14.17	14.17
PUBLICLY OWNED ENTITY	16.64	17.17	16.57	1.72	14.48	14.48	2.68
END USER	6.87	13.35	13.21	3.81	11.25	11.25	5.94
% IN FAVOR	47.95	78.64	77.90	30.99	60.76	64.70	49.50

GENERATION

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Dominion Energy Marketing, Inc.	A	--	--	O	F	F	O
Entergy Nuclear Power Marketing	A	F	F	O	F	F	O
EquiPower Resources Management	A	F	F	O	F	F	A
Essential Power	A	F	F	O	F	F	O
GDF SUEZ Energy Marketing N. Amer.	A	F	F	O	F	F	A
Generation Group Member	O	F	F	O	F	--	A
Millennium Power Partners	A	F	F	O	F	F	A
NextEra Energy Resources	A	F	F	O	--	A	O
NRG Power Marketing	A	F	F	O	--	A	O
TransCanada Power Marketing	A	F	F	O	F	F	O
Verso Maine Energy	A	F	F	O	F	F	A
IN FAVOR (F)	0	10	10	0	9	8	0
OPPOSED (O)	1	0	0	11	0	0	6
TOTAL VOTES	1	10	10	11	9	8	6
ABSTENTIONS (A)	0	0	0	0	0	2	5

TRANSMISSION

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Bangor Hydro-Electric Co.	F	O	O	F	O	O	F
Central Maine Power Co.	F	O	O	F	O	O	F
New England Power Co.	A	O	O	F	O	O	F
The United Illuminating Co.	F	F	F	A	O	A	F
NU /NSTAR	A	F	F	F	O	O	F
Vermont Electric Power Co.	F	O	O	F	O	O	F
Provisional Group Member	O	--	--	--	--	--	--
IN FAVOR (F)	4	2	2	5	0	0	6
OPPOSED (O)	0	4	4	0	6	5	0
TOTAL VOTES	4	6	6	5	6	5	6
ABSTENTIONS (A)	2	0	0	1	0	1	0

ALTERNATIVE RESOURCES

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Renewable Generation							
First Wind Energy Marketing	O	F	F	O	F	F	F
Small RG Group Member	A	A	A	A	--	A	A
Distributed Generation							
Conservation Services Group	A	O	O	F	O	F	F
Small DG Group Member	O	F	F	O	O	F	F
Load Response							
Comverge, Inc.	A	F	F	--	--	--	--
EnerNOC, Inc.	A	A	A	A	F	F	F
Vermont Energy Investment Corp.	A	O	O	F	O	F	F
Small LR Group Member	A	O	O	F	O	F	F
LR Provisional Group Member	A	O	O	--	O	F	F
IN FAVOR (F)	0	3	3	3	2	7	7
OPPOSED (O)	2	4	3	2	5	0	0
TOTAL VOTES	2	7	6	5	7	7	7
ABSTENTIONS (A)	7	2	2	2	0	1	1

VOTES TAKEN AT
AUGUST 2, 2013 PARTICIPANTS COMMITTEE MEETING

SUPPLIER

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
BP Energy Co.	A	F	F	A	F	A	F
Brookfield Energy Marketing/CSC	O	F	F	S	S	A	A
Brookfield (70%, when split)				O	A		
Cross-Sound Cable (30%, when split)				A	F		
Calpine Energy Services	A	F	F	O	F	F	O
Competitive Energy Services	--	F	F	O	A	--	A
Consolidated Edison Energy	O	F	F	A	F	F	A
CP Energy Marketing (US)	A	F	F	O	F	F	O
Dynegy Marketing and Trade	A	F	F	O	F	A	O
Energy America	A	F	F	A	O	O	F
Exelon Generation Co.	--	F	F	A	F	A	A
Galt Power	A	A	A	A	A	A	A
Granite Ridge/Merrill Lynch Commodities.	A	F	F	O	F	A	A
H.Q. Energy Services (U.S.)	O	F	F	O	F	F	A
Hess	--	F	F	A	O	O	A
Integrys Energy Services	A	F	F	A	O	O	F
Kimberly-Clark Corp.	F	A	A	A	A	A	F
Linde Energy Services	F	A	A	A	O	O	F
LIPA	O	F	F	A	A	A	A
PPL EnergyPlus	F	F	F	O	F	A	A
PSEG Energy Resources & Trade	A	F	F	O	F	O	O
Vitol	A	F	F	O	A	--	--
IN FAVOR (F)	3	17	17	0	10.3	4	5
OPPOSED (O)	4	0	0	9.7	4.0	5	4
TOTAL VOTES	7	17	17	9.7	14.3	9	9
ABSTENTIONS (A)	10	3	3	10.3	5.7	9	10

PUBLICLY OWNED ENTITY

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Ashburnham Municipal Light Plant	F	F	F	O	F	F	O
Boylston Municipal Light Dept.	F	F	F	O	F	F	O
Chicopee Municipal Lighting Plant	F	F	F	O	F	F	O
Concord Municipal Light Plant	F	F	F	O	F	F	O
CT Municipal Electric Energy Coop.	F	A	O	F	O	O	F
Groton Electric Light Dept.,	F	F	F	O	F	F	O
Holden Municipal Light Dept.	F	F	F	O	F	F	O
Holyoke Gas & Electric Dept.	F	F	F	O	F	F	O
Hudson Light and Power Dept.	F	F	F	O	F	F	O
Hull Municipal Lighting Plant	F	F	F	O	F	F	O
Ipswich Municipal Light Dept.	F	F	F	O	F	F	O
Littleton (NH) Water & Light Dept.	F	A	A	F	O	O	F
Mansfield Municipal Electric Dept.	F	F	F	O	F	F	O
Marblehead Municipal Light Dept.	F	F	F	O	F	F	O
Mass. Municipal Wholesale Electric Co.	F	F	F	O	F	F	O
Middleborough Gas and Electric	F	F	F	O	F	F	O
Middleton Municipal Electric Dept.	F	F	F	O	F	F	O
New Hampshire Electric Coop.	F	A	A	A	O	O	F
Paxton Municipal Light Dept.	F	F	F	O	F	F	O
Peabody Municipal Light Plant	F	F	F	O	F	F	O
Princeton Municipal Light Dept.	F	F	F	O	F	F	O
Rowley Municipal Lighting Plant	F	F	F	O	F	F	O
Russell Municipal Light Department	F	F	F	O	F	F	O
Shrewsbury's Electric & Cable Operations.	F	F	F	O	F	F	O
South Hadley Electric Light Dept.	F	F	F	O	F	F	O
Sterling Municipal Electric Light	F	F	F	O	F	F	O
Taunton Municipal Lighting Plant	F	A	F	A	A	A	A
Templeton Municipal Lighting Plant	F	F	F	O	F	F	O
Vermont Electric Cooperative	O	A	A	F	O	O	F
VT Public. Power Supply Authority	F	A	A	A	O	O	F
Wakefield Municipal Gas and Light	F	F	F	O	F	F	O
W. Boylston Municipal Lighting Plant	F	F	F	O	F	F	O
Westfield Gas & Electric Light Dept.	F	F	F	O	F	F	O
IN FAVOR (F)	32	27	28	3	27	27	5
OPPOSED (O)	1	0	1	27	5	5	27
TOTAL VOTES	33	27	29	30	32	32	32
ABSTENTIONS (A)	0	6	4	3	1	1	1

VOTES TAKEN AT
AUGUST 2, 2013 PARTICIPANTS COMMITTEE MEETING

END USER

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5	Vote 6	Vote 7
Associated Industries of MA	A	F	F	O	O	O	F
Cianbro Companies	A	F	F	O	F	F	O
Conservation Law Foundation	A	O	O	F	F	F	O
Corinth Wood Pellets, LLC	A	F	F	O	F	F	O
Dragon Products Company	A	F	F	O	F	F	O
Elektrisola, Inc.	A	F	F	O	F	F	O
Fairchild Semiconductor Corp.	A	F	F	O	F	F	O
Food City, Inc.	A	F	F	O	F	F	O
Hardwood Products Company	A	F	F	O	F	F	O
Harvard Dedicated Energy Limited	A	F	F	O	O	O	F
High Liner Foods (USA) Inc.	A	F	F	O	F	F	O
Industrial Energy Consumer Group	A	F	F	O	F	F	A
LaBree's Inc.	A	F	F	O	F	F	O
Maine Public Advocate Office	O	O	O	F	O	O	F
Maine Skiing, Inc.	A	F	--	O	F	F	A
Marden's Inc.	A	F	F	O	F	F	O
Mass. Attorney General's Office	F	O	O	F	O	O	F
MoArk, LLC	A	F	F	O	F	F	O
NH Office of Consumer Advocate	O	O	O	F	O	O	F
PalletOne of Maine	A	F	F	O	F	F	O
PowerOptions, Inc.	O	O	O	F	O	O	F
Praxair, Inc.	F	A	A	A	O	O	F
Shipyard Brewing Co.	A	F	F	O	F	F	O
St. Anselm College	A	F	F	O	F	F	O
The Energy Consortium	A	F	F	O	O	O	F
Union of Concerned Scientists	A	O	O	F	O	O	F
Utility Services	A	A	A	A	O	O	A
Westerly Hospital	A	F	F	O	F	F	O
Z-TECH, LLC	A	F	F	O	F	F	O
IN FAVOR (F)	2	21	20	6	19	19	9
OPPOSED (O)	3	6	6	21	10	10	17
TOTAL VOTES	5	27	26	27	29	29	26
ABSTENTIONS (A)	24	2	2	2	0	0	3