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February 5, 2007

VIA ELECTRONIC FILING

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

**Re: ISO New England Inc. and New England Power Pool;
Docket No. ER07-397-000**

Dear Secretary Salas:

Transmitted electronically for filing in the referenced docket is the Motion for Leave to Answer and Answer of ISO New England Inc. and the New England Power Pool.

If there are any questions concerning this filing, please call me at (202) 661-2212.

Very truly yours,

/s/ Daniel R. Simon

Daniel R. Simon
Counsel for
ISO New England Inc.

Enclosure

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**ISO New England Inc. and
New England Power Pool**

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Docket No. ER07-397-000

**MOTION FOR LEAVE TO ANSWER AND ANSWER
OF ISO NEW ENGLAND INC. AND
THE NEW ENGLAND POWER POOL**

Pursuant to Rule 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (the “Commission”), 18 C.F.R. § 385.213 (2006), ISO New England Inc. (the “ISO” or “ISO-NE”) and the New England Power Pool Participants Committee (“NEPOOL”) hereby submit this joint response (“Answer”) to the protests filed in the above-captioned docket on January 19, 2007 by Central Maine Power Company (“CMP”) and the Maine Public Utilities Commission (“Maine PUC”) (together, the “Protests”).

The ISO and NEPOOL ask the Commission to grant leave to accept this Answer, to reject the Protests, and to accept, without suspension or hearing, the revised tariff sheets included with their Section 205 filing of December 29, 2006 (the “December 29 Filing”) to amend the reactive power payment provisions of Schedule 2 of the ISO OATT (the “Schedule 2 Amendments”).¹

I. MOTION FOR LEAVE TO ANSWER

Because an answer is not normally permitted in response to protests, the ISO and NEPOOL hereby move, pursuant to Rule 212 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.212 (2006), for leave to accept this answer. The Commission has the

¹ The ISO OATT is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3 (the “Tariff”). Capitalized terms not defined herein have the meanings ascribed thereto in the Tariff.

authority to waive the prohibition against answers to protests for good cause.² The Commission has found good cause to permit answers where they are otherwise prohibited in various circumstances, including where the answer would assure a complete record in the proceeding,³ provide information helpful to the disposition of an issue,⁴ permit the issues to be narrowed or clarified,⁵ or aid the Commission in understanding and resolving issues.⁶ The ISO and NEPOOL believe that this answer will assure a more complete record in this proceeding and otherwise assist the Commission in understanding and resolving the issues presented. Furthermore, the Commission has accepted answers by the ISO under similar circumstances.⁷

II. BACKGROUND

As the December 29 Filing explains, the ISO and NEPOOL have worked together through a lengthy process to develop Schedule 2 Amendments that will provide reliability benefits to New England and appropriate payment to suppliers of dynamic reactive power to the New England Transmission System. The Schedule 2 Amendments have the support of 88 percent of NEPOOL. In December 2004, the NEPOOL Transmission Committee established a VAR Working Group (the “VWG”) to review the rules in New England governing the provision of reactive power and voltage support, including eligibility of Resources, compensation and

² See 18 C.F.R. § 385.101(e) (2006).

³ See, e.g., *Pacific Interstate Transmission Co.*, 85 FERC ¶ 61,378, at 62,443 (1998), *reh’g denied*, 89 FERC ¶ 61,246 (1999).

⁴ See, e.g., *CNG Transmission Corp.*, 89 FERC ¶ 61,100, at 61,287 n.11 (1999).

⁵ See, e.g., *PJM Interconnection, LLC*, 84 FERC ¶ 61,224, at 62,078 (1998); *New Energy Ventures, Inc. v. Southern California Edison Co.*, 82 FERC ¶ 61,335, at 62,323 n.1 (1998).

⁶ See, e.g., *Tennessee Gas Pipeline Co.*, 92 FERC ¶ 61,009, at 61,016 (2000).

⁷ See *ISO New England Inc.*, 113 FERC ¶ 61,341 at P 6 (2005) (accepting ISO’s answer to protests to 2006 rates); *ISO New England Inc.*, 109 FERC ¶ 61,383 (2004) (accepting ISO’s answer to protests to 2005 rates); *ISO New England Inc.*, 97 FERC ¶ 61,304 (2001) (accepting ISO’s answer to protests to 2002 rates).

testing, to recommend whether those rules should change and, if so, how they should change.⁸

Per the Transmission Committee's directive, the VWG held monthly meetings from January 2005 to April 2006 to review and develop recommendations with respect to the rules governing eligibility for reactive power compensation in New England.⁹

The Schedule 2 Amendments proposed in the December 29 Filing reflect the recommendations of the VWG, as further modified and subsequently supported by both the Transmission Committee and the Participants Committee.¹⁰ The ISO and NEPOOL jointly filed the Schedule 2 Amendments, as overwhelmingly supported in the stakeholder process.

The Schedule 2 Amendments proposed the following primary changes to the ISO OATT's existing Schedule 2:

1. expand eligibility for payment under Schedule 2 to non-generator dynamic reactive power Resources;
2. make eligibility criteria clear for all dynamic reactive power Resources;
3. update the Capacity Cost ("CC") rate from \$1.05/kVAR-year (the current amount paid under the CC rate) to \$2.32/kVAR-year to account for new generation (and its related costs) added to the mix of dynamic reactive Resources in New England since 1998;
4. use both leading and lagging VAR capability to determine the CC rate payments; and
5. identify an alternative means under the OATT by which a non-generator dynamic reactive power Resources can receive compensation if it does not elect to recover its costs under Schedule 2.¹¹

⁸ December 29 Filing, Transmittal Letter at 2 n.4; *id.* at 19.

⁹ *Id.* at 19 n.31.

¹⁰ *Id.* at 20.

¹¹ *See generally id.* at 8-19.

Cross-Sound Cable Company, LLC, the Long Island Power Authority, and the Mirant Parties¹² all filed comments in support of the December 29 Filing. Only two entities filed protests: CMP and the Maine PUC. The Protests raised four specific issues of concern: (i) the ISO OATT’s existing reactive power cost allocation methodology is unjust and unreasonable;¹³ (ii) generators need not be paid for providing reactive power support within any power factor ranges required by interconnection agreements (the “Deadband Proposal”);¹⁴ (iii) the proposed VAR rate increase will provide Resources double recovery for the same service, in light of the provisions of the Forward Capacity Market (“FCM”);¹⁵ and (iv) the December 29 Filing fails to justify the proposed CC rate increase.¹⁶ These limited issues are the subject of this Answer.

III. ANSWER

A. Because the Protestors Fail to Satisfy the Substantive and Procedural Requirements of Section 206, the Commission Should Leave the Existing Schedule 2 Cost Allocation Methodology Unaltered and Allow the Ongoing Stakeholder Process to Fully Examine This Issue

The December 29 Filing does not propose to change the existing, Commission-approved allocation of Schedule 2 costs—a fact the Protestors recognize.¹⁷ Nevertheless, the Protestors ask the Commission to use this proceeding to change the ISO OATT’s existing filed rate for

¹² The Mirant Parties are Mirant Energy Trading, LLC; Mirant Canal, LLC; and Mirant Kendall, LLC.

¹³ CMP Protest at 4-5; Maine PUC Protest at 6-7.

¹⁴ Maine PUC Protest 9-10.

¹⁵ CMP Protest at 3; Maine PUC Protest at 8-9.

¹⁶ CMP Protest at 3; Maine PUC Protest at 7.

¹⁷ CMP Protest at 4 (noting that “[t]he Schedule 2 Amendments would *continue* the socialization of VAR uplift costs” and arguing that “[t]his market design flaw ... should not be allowed to continue” (emphasis added)); Maine PUC Protest at 1 (protesting “the filing parties’ decision to *continue* socializing uplift costs for voltage support ...” (emphasis added)).

VAR cost allocation.¹⁸ The Commission should reject this request. Absent a filing pursuant to Section 205 of the Federal Power Act (“FPA”), the Commission could only change the ISO’s filed rate pursuant to Section 206 of the FPA. The Protestors failed to file a Section 206 complaint, and have not met their Section 206 burden of proof. As a matter of law, therefore, the Protests on this point must be rejected.

As the D.C. Circuit has explained, a Commission-imposed change (whether initiated by the Commission or another entity) in either the “rates or their method of calculation” must be accomplished through Section 206 of the FPA or the analogous Section 5 of the Natural Gas Act.¹⁹ Thus, “when the Commission imposes a change not proposed by the natural gas company – including *an alteration in an unchanged part of a proposed higher rate* – it must first find that the existing provision is unjust or unreasonable.”²⁰ Of particular relevance here, in *Sea Robin Pipeline Co. v. FERC*, 795 F.2d 182 (D.C. Cir. 1986), the D.C. Circuit reversed the Commission for attempting to change the pipeline’s *cost allocation* methodology pursuant to Section 4 of the Natural Gas Act in response to a proposed rate hike by the pipeline that left the cost allocation methodology unaltered.²¹ Because the Protestors in the instant matter failed to meet their

¹⁸ CMP Protest at 4-7 (opposing the extant Schedule 2 provisions that allocate reactive power costs to all regional network load and reserved capacity for through and out transactions); Maine PUC Protest at 6-7 (asking the ISO to adopt its Independent Market Monitor’s recommendation to change the existing reactive power cost allocation methodology from a regional to a local basis).

¹⁹ *Sea Robin Pipeline Co. v. FERC*, 795 F.2d 182, 186 (D.C. Cir. 1986); *see also Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 115 FERC ¶ 61,053 (2006) (acknowledging “the proposition that when the Commission seeks to change ... *an unchanged part of an otherwise changed rate*, we must first show the existing rate or practice to be unjust, unreasonable, unduly discriminatory, or preferential before ordering the change”) (citations omitted).

²⁰ *ANR Pipeline Co. v. FERC*, 771 F.2d 507, 514 (D.C. Cir. 1985); *see also Sea Robin Pipeline Co.*, 795 F.2d 186-87 (quoting ANR Pipeline and reversing the Commission for changing the pipeline’s cost allocation methodology pursuant to Section 4 of the Natural Gas Act).

²¹ *Id.*

Section 206 burden (to demonstrate that the existing VAR cost allocation is unjust and unreasonable), the Commission should reject the calls to change the ISO's VAR cost allocation methodology.

Furthermore, Commission precedent is clear that a party may not include a complaint challenging an existing aspect of the filed rate in a protest to a Section 205 filing.²² Because the December 29 Filing does not change the ISO's VAR cost allocation methodology, the Protestors' attempt to change it through a protest of the Section 205 filing is procedurally impermissible and should be rejected.

The Protestors note that their proposal to alter the current VAR cost allocation methodology earned 60 percent support by the NEPOOL Participants Committee.²³ The official voting result, which was 57.59 percent support, was well short of the requisite 66.67 percent or higher vote required for NEPOOL to support a change to the ISO's VAR cost allocation methodology. This level of support does not justify a change that neither the ISO nor NEPOOL have proposed to the VAR cost allocation methodology.

Nevertheless, the ISO and NEPOOL agree that this level of support justifies further review of the current cost allocation methodology through the stakeholder process. If a change acceptable to ISO and/or NEPOOL emerges from that process, the VAR costs allocation methodology can be modified accordingly in a Section 205 filing. The ISO, NEPOOL, and the New England Conference of Public Utility Commissioners, Inc. ("NECPUC") already have

²² See, e.g., *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,248 at P 5 (2004) (noting that the Commission has consistently rejected efforts to combine complaints with other types of filings); *Consolidated Edison Company of New York*, 97 FERC ¶ 61,241 at 62,092 & n.14 (2001) (citing *Louisiana Power and Light Company*, 50 FERC ¶ 61,040 at 61,062-63 (1990)); *Entergy Services, Inc.*, 52 FERC ¶ 61,317 at 62,270 (1990) (noting that complaints must be filed separately from motions to intervene and protests).

²³ CMP Protest at 5; Maine PUC Protest at 5.

created a working group to address certain cost allocation methodologies reflected in the Tariff. The ISO will ask the working group to address the VAR cost allocation issue following the conclusion of the working group's ongoing review of the cost allocation for Local Second Contingency Protection Resources.²⁴ Specifically, the ISO will discuss the VAR cost allocation issue with the working group to evaluate the current and potential alternative methods, the underlying policies and implementation requirements for allocating Schedule 2 costs, and whether any changes should be proposed to the current just and reasonable method for allocating such costs within New England.²⁵

Allowing the continued use of the existing working group process will provide the best means for stakeholders and the ISO to work together to determine whether the current cost allocation methodology should be changed and, if so, how to make such changes without creating any unforeseen adverse impacts. This stakeholder process will openly and objectively evaluate this issue. Although neither NEPOOL nor the ISO at this time is prepared to state whether (or how) the cost allocation methodology ultimately should be changed, this stakeholder process should examine, *inter alia*, the recommendation made in the 2004 report of the Independent Market Monitoring Unit²⁶ to allocate VAR costs to local load with a "split" cost allocation that regionalizes costs during high load and low voltage conditions but localizes costs during low load and high voltage conditions.

²⁴ December 29 Filing, Transmittal Letter at 21 n.35.

²⁵ *Id.*

²⁶ See David B. Patton and Pallas LeeVanSchaick, Potomac Economics, Ltd., 2004 Assessment of the Electricity Markets in New England (June 2005), *available at* http://www.iso-ne.com/pubs/spcl_rpts/2004/2004_immu_report_final_6_30.pdf.

B. The Commission Should Reject the Deadband Proposal Because Commission Precedent Allows Generators to Be Compensated For Operating Within the Established Power Factor Range

The Maine PUC also asks the Commission to reject the Schedule 2 Amendments and “direct ISO-NE and NEPOOL to consider other alternatives,” including the Deadband Proposal – presented by the Maine PUC in the stakeholder process – that would not compensate generators for reactive power when operating within the established power factor range.²⁷ Specifically, the Deadband Proposal would “replace[] the *current* VAR cc methodology” with one under which “generators would be compensated only for the capability to provide reactive support outside the dead band of 95 percent leading and 95 percent lagging power factor.”²⁸ The Commission should reject the Maine PUC’s request for several reasons.

First, Schedule 2 already provides payment to qualified generators for their reactive power capabilities, including within any required power factor range, in recognition that it is appropriate to compensate them to provide this service, even if interconnected generators are required by way of their interconnection agreements to operate within this range to control voltage. This approach is consistent with Commission precedent recognizing that a generator is “used and useful” if *capable* of providing reactive power.²⁹

Second, as discussed above in Section III.A, because the December 29 Filing does not seek to change this aspect of the Schedule 2 filed rate, any attempt by the Maine PUC to eliminate such compensation must meet the requirements of Section 206 of the FPA. Clearly,

²⁷ Maine PUC Protest at 9-10.

²⁸ *Id.* at Attachment B, p. 2 (emphasis added).

²⁹ *Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282 at P 28 (2006) (discussing *Midwest Independent Transmission System Operator, Inc.*, 114 FERC ¶ 61,192 at P 19 (2006)).

the Maine PUC has not filed a Section 206 complaint nor otherwise met its burden under Section 206. The fact that the Maine PUC offered another proposal in the stakeholder process that also might be just and reasonable is a legally insufficient foundation on which to require the ISO to adopt it.³⁰ As a matter of law, therefore, the Maine PUC protest on this point must be rejected.

Third, Commission precedent, as the Maine PUC implicitly recognizes,³¹ *does not prohibit* a regional transmission organization (“RTO”) such as the ISO (or other public utility) from choosing to compensate generators for their reactive power capabilities within the established power factor range. Instead, as the Commission recently emphasized, a generator is allowed to receive such compensation so long as “another generator within the control area is already receiving compensation for it.”³² Because the ISO compensates all generators providing reactive power within the established power factor range on a comparable basis – a fact the Maine PUC Protest does not contest – the ISO’s existing approach is consistent with Commission policy.

³⁰ See, e.g., *ISO New England Inc.*, 114 FERC ¶ 61,315 at P 33 & n.35 (2005) (refusing to evaluate an alternative proposal when the filing utility has demonstrated that its proposal is just and reasonable) (citing *Pub. Serv. Co. of New Mexico v. FERC*, 832 F.2d 1201, 1211 (10th Cir. 1987); *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir.1984)). As the December 19 Filing indicates, the Maine PUC’s Deadband Proposal also failed to receive the necessary stakeholder support to warrant a change of the status quo. December 29 Filing, Transmittal Letter at 20.

³¹ *Id.* at 10 (acknowledging that the Commission allows generators to be compensated for providing reactive power within the established power factor so long as the transmission provider compensates its affiliated generators on an equal basis) (citing *Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282 at P 26 (2006) (“*Calpine Oneta Power*”).

³² *Calpine Oneta Power*, 116 FERC ¶ 61,282 at P 50 n. 62. Although Commission policy provides that “[g]enerators interconnected to a transmission provider’s system *need* only be compensated where the transmission provider directs the generator to operate *outside* the established power factor range,” see *Calpine Oneta Power* at P 26, it does not prohibit such compensation. In fact, the Commission provides that, to the extent a “transmission provider compensates its own or its affiliated generators for reactive power *within* the established range, it *must* also pay the interconnecting generator.” *Id.* (citations omitted).

Finally, Commission policy has repeatedly acknowledged the appropriateness of allowing an RTO or ISO to compensate generators for having the capability to provide reactive power within the established power factor range, if done on a comparable basis. For example, in promulgating the standardized Large Generator Interconnection Agreement, Order No. 2003³³ recognized that RTOs and ISOs in particular may chose to compensate generators in this fashion because, *inter alia*, “[a]n RTO or ISO has different operating characteristics depending on its size and location and is less likely to act in a discriminatory manner than a Transmission Provider that is also a market participant.”³⁴ In addition, the Commission recently reiterated in *Calpine Oneta Power* that it “continue[s] to find” this compensation methodology (referred to as the “AEP methodology”³⁵) “appropriate” when “based on capability *as established by an RTO/ISO*.”³⁶ In fact, the Commission in that case *required SPP – an RTO – to compensate the filing generator for the capability of operating within the established power factor range*.³⁷ It is

³³ *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,845 (Aug. 19, 2003), FERC Stats. & Regs., Regulations Preambles ¶ 31,146 (2003) (Order No. 2003), *order on reh’g*, Order No. 2003-A, 69 Fed. Reg. 15,932 (March 26, 2004), FERC Stats. & Regs., Regulations Preambles ¶ 31,160 (2004) (Order No. 2003-A), *order on reh’g*, 109 FERC ¶ 61,287 (2004) (Order No. 2003-B), *order on reh’g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005) (Order No. 2003-C).

³⁴ Order No. 2003 at P 548.

³⁵ The Schedule 2 Amendments update the CC rate by utilizing data from AEP methodology filings made by generators in PJM. *See* December 29 Filing, Transmittal Letter at 12 & Attachment 3.

³⁶ *Calpine Oneta Power*, 116 FERC ¶ 61,282 at P 50 (emphasis added). Although the Commission in that case suggested “that perhaps the Commission’s reactive power compensation approach for generators providing reactive power within their established power factor range based on capability may not be appropriate in all circumstances” because there was “between three and ten times the reactive power capability as is needed in the Tulsa area where the Oneta Facility is located,” the Maine PUC Protest provides no such evidence here.

³⁷ *Id.* at P 27 (“Here, SPP’s Schedule 2 allows AEP’s generators to receive compensation for providing reactive power within the established power factor range, but not the Oneta Facility. Consistent with the Commission’s reactive power comparability standard, Oneta must also receive compensation. No further inquiry is required.”); *id.* at P 2 (directing SPP “to compensate all generators under Schedule 2 ... on a comparable basis”).

no surprise, therefore, that several RTOs and ISOs (*e.g.*, Midwest ISO,³⁸ NYISO,³⁹ PJM,⁴⁰ SPP⁴¹) – in addition to ISO-NE – compensate generators for the capability to provide reactive power support, including within established power factor ranges.

For these reasons, the Commission should reject the Maine PUC’s request that the ISO eliminate the extant provisions of Schedule 2, so that Resources would no longer be compensated for their reactive power capabilities within the established power factor range.

C. The Schedule 2 Amendments Do Not Create a “Double Compensation” Problem

The Protests also ask the Commission to reject the Schedule 2 Amendments because capacity payments provided by the recently approved Forward Capacity Market Settlement Agreement (the “FCM Settlement”)⁴² allegedly will fully compensate Resources for their capacity costs, including for the ability to produce or absorb reactive power within the predefined range. The Protests argue that, as a result, the Schedule 2 Amendments (through their capacity charge (“CC”) element) will “double compensate” Resources for this capability.⁴³ This

³⁸ *Midwest Independent Transmission System Operator, Inc.*, 114 FERC ¶ 61,192 at P 19 (noting that the Midwest ISO’s Schedule 2 compensates generators for the *capability* of providing reactive power within a specified range when called upon).

³⁹ *New York Independent System Operator, Inc.*, 114 FERC ¶ 61,271 at P 41 (2006) (noting that “all generators [in the NYISO control area] are compensated for reactive power”).

⁴⁰ *Calpine Oneta Power*, 116 FERC ¶ 61,282 at P 50 n.60 (citing PJM’s Schedule 2).

⁴¹ *Id.* at P 27 (requiring SPP to compensate Calpine Oneta for providing reactive power within the established power factor range because SPP’s Schedule 2 provided AEP’s generators such compensation).

⁴² *Devon Power LLC*, 115 FERC ¶ 61,340, *reh’g*, 117 FERC ¶ 61,133 (2006).

⁴³ *See, e.g.*, CMP Protest at 3 (“The capacity payments that are provided by the recently approved Forward Capacity Market (“FCM”) Settlement, will charge customers and pay generators to ensure that generators are fully compensated for their costs and, therefore, customers are entitled to receive all reliability benefits associated with that capacity. In order to be interconnected, generators are required to be able to produce or absorb reactive power within a predefined range. Payments under the FCM fully compensate generators for providing this capability. Additional payments under this proposal appear to double compensate generators for the same service, at least for providing reactive power within the predefined range.”); Maine
(continued...)

concern is premature. The Maine PUC's concerns in this regard should and will be considered prior to the implementation of FCM. Therefore, the Commission should reject the concerns raised here by the Protests.

To fully understand the argument regarding potential "double compensation," it is important to distinguish two separate FCM phases: (i) the FCM transition payments; and (ii) the derivation of capacity prices through the first Forward Capacity Auction ("FCA"). The FCM Settlement, as approved by the Commission,⁴⁴ provides the general requirements for the ISO's implementation of the FCM transition payments and FCA implementation.

The FCM transition payments,⁴⁵ which Resources began to earn as of December 1, 2006, do not suggest any double compensation concerns. The compensation that Resources earn through the FCM transition payments is based on a negotiated rate agreed to in the FCM Settlement, not a market-based measure. Over the course of the transition period, the FCM transition payment rate will increase, but not to a level equal to the cost of new entry to be used in the first FCA. As a result, the FCM transition payments will likely be at a level *below* the actual cost of providing both installed capacity and reactive power. As a result, the FCM transition payments do not compensate Resources for their reactive power capabilities.

(...continued)

PUC Protest at 8-9 (arguing that the FCM transition payments already compensate generators for their investment, and such payments should offset the revenue requirement used in determining the reactive power charge).

⁴⁴ See *Devon Power LLC*, 115 FERC ¶ 61,340, *reh'g*, 117 FERC ¶ 61,133 (2006).

⁴⁵ The Commission accepted the Tariff amendments implementing the FCM transition payments in *ISO New England Inc. and New England Power Pool*, 117 FERC ¶ 61,132 (2006). On December 27, 2006, the Commission granted rehearing for further consideration in Docket No. ER06-1465-001.

The ISO and NEPOOL will consider the potential for double compensation prior to when the FCA is fully implemented for the first FCA commitment year (*i.e.*, 2010).⁴⁶ They will look at market-based capacity payment for 2010, when FCM payments will be set by the market and will reflect the actual cost of new entry as revealed by new Resources entering the market. To the extent that such Resources will be required to meet minimum reactive power requirements, the cost of that capability could be reflected in the Resources' capacity offers. If that occurs, Schedule 2 CC payments could result in double compensation.

If double compensation were to be a continuing concern in 2010, the ISO, NEPOOL and the Commission will have full power to address the concern prior to that time. Any solution would need to consider and balance all factors, and ensure that there is sufficient incentive and compensation for Resources to provide Schedule 2 service. The ISO commits to proposing, for implementation prior to the first FCA commitment year, Tariff provisions to ensure that Resources eligible for CC payments under Schedule 2 for providing reactive supply and voltage control do not receive double compensation.

In light of these considerations, it is just and reasonable for the Commission to accept the Schedule 2 Amendments in recognition of the ISO's commitment to resolving the double compensation problem before it materializes in 2010.

D. The December 29 Filing Provides Sufficient Justification for the Revised CC Rate

The ISO and NEPOOL submit that the December 29 Filing provided sufficient justification for the increase in the CC rate proposed in the Schedule 2 Amendments, including an explanation of the numeric basis for the new rate and why it is a practical, efficient solution to

⁴⁶ The first FCA will be held in 2008 to commit participating Resources to provide capacity beginning in 2010.

how to value dynamic reactive power capability that avoids regulatory litigation. In a way, the proposed increased CC rate can be viewed as a settlement (with 88% NEPOOL support) in advance of a contested proceeding.⁴⁷

The December 29 Filing explained⁴⁸ the reason for increasing the CC rate from \$1.05/kVAR-year to \$2.32/kVAR -year, which is that the existing CC rate does not reflect the higher costs of new generators providing reactive power support that have been built in New England since the initial CC rate was developed. Increasing the CC rate will appropriately compensate qualified reactive Resources and thereby promote dynamic reactive power capability and its reliability benefit for New England.

The December 29 Filing explained⁴⁹ the basis for the new CC rate, which was a negotiated rate based on a weighted-average blend of costs of older generators in New England, and the costs of newer units as reflected in AEP methodology⁵⁰ filings in PJM. The ratio for the blend of those costs was two-thirds to one-third. The reason for using this ratio is that it reflects the approximate ratio of megawatts of pre-market⁵¹ generation (pre-1998, roughly 20,000 MWs)

⁴⁷ Of note is the fact that the proposed new CC rate was initially developed by a sub-group of generators and transmission owners, two groups that do not often agree on rate matters affecting generators and transmission customers.

⁴⁸ See, e.g., December 29 Filing, Transmittal Letter at 8 & 12-13.

⁴⁹ See, e.g., *id.* at 12-13.

⁵⁰ See *American Electric Power Service Corporation*, 88 FERC ¶61,141 (1999) (the initial case establishing the “AEP Methodology”). The AEP Methodology determines the cost of the generator, exciter and step-up transformer, allocates a portion to VAR capability and levelizes that cost over the life of the unit to get a VAR cost of service rate.

⁵¹ The competitive bid-based markets commenced in New England in 1998. Approximately 10,000 MW of generation in New England has become operational since 1998.

and post-market generation (1998 and after, roughly 10,000 MWs) currently existing in New England.

The pre-market (*i.e.*, pre-1998) generation was used to develop the current CC revenue requirement and the current Base VAR Rate of \$1.05/kVAR-year. It is important to note that *the current “Base VAR Rate” is itself the result of a series of negotiated annual rates that are based on a number of estimates of the carrying cost per kVAR per year to generators associated with the equipment to provide VAR Support.*⁵² To arrive at the current rate, first the cost bases of NEPOOL Transmission Owners as of 1998 were reviewed. Prior to the effective date of Schedule 2 in the NEPOOL Tariff, the costs of providing VAR Support from generators owned by a number of Transmission Owners had been quantified and reflected in the regulated rates of their local transmission tariffs. The average cost of VAR Support reflected in the rates of such Transmission Owners was approximately \$1.38/kVAR-year exclusive of any variable costs. Second, similar data for the New York State utilities, PJM utilities, and American Electric Power was obtained and it was determined that the average VAR costs underlying the rates for these utilities ranged from \$1.58 to \$3.72/ kVAR -year. Finally, an estimate of NEPOOL’s avoidable cost of installing static reactor/capacitor banks to provide transmission-based VAR support capability was determined to be approximately \$0.64/kVAR-yr.

Given the variation in the average \$/kVAR -year rates described above, the magnitude of potential CC charges and the desire to find an administratively efficient and simple way to quantify CC charges, the Participants agreed in 2000 to utilize a proxy value (*i.e.*, the Base VAR Rate) for defining the carrying costs associated with providing the capability for VAR Support

⁵² Reactive power is expressed in units of volt-ampere reactive (VAR), thousands of volt-ampere reactive (kVAR), or millions of volt-ampere reactive (MVAR).

that would be captured in the CC charge. The agreed-upon value was \$0.90/kVAR-yr in 2001, increasing to \$0.95/kVAR-yr in 2002, to \$1.00/kVAR-yr in 2003, and to \$1.05/kVAR-yr in 2004 and “thereafter.” *Thus, there is clear precedent in the existing, Commission-approved CC rate for a negotiated average CC rate as is now proposed in the Schedule 2 Amendments.*

The December 29 Filing explained⁵³ that the average rate blended the costs of the older units (as reflected in the \$1.38/kVAR -year revenue requirement described in the preceding paragraph) with a proxy rate for new generation in New England. As shown above, use of a proxy value for the Schedule 2 CC rate was already established as a precedent.⁵⁴ The proxy chosen to develop the new CC rate was a set of newer (vintage 2000 and after) combined cycle gas-fired generators in PJM whose reactive power costs had undergone scrutiny through AEP methodology filings and Commission review. Using publicly available data from this set of generators was reasonable because: (1) the generators are a similar vintage and technology (*i.e.*, post-1998 combined cycle, gas-fired generators), and in most if not all cases have the same manufacturer, as the majority of the post-market generation in New England; (2) the revenue requirement numbers had undergone scrutiny through the Commission review and approval

⁵³ See, *e.g.*, December 29 Filing, Transmittal Letter at 12-13.

⁵⁴ Additionally, Schedule 16 of the ISO OATT (“System Restoration Service,” *i.e.*, Blackstart capability) also uses a negotiated proxy rate that was derived partly based on relevant cost data from other regions. In 2000, the Commission approved a proxy rate for the capital structure used in the Schedule 16 rate stating: “We believe that, of the various proposals before us, the use of a proxy capital structure and proxy costs of capital, as proposed by the Black Start Service Suppliers, is reasonable in these circumstances. In addition, use of proxies is likely to avert litigation over capital costs in the future and avoid the need to disclose actual capital cost data.” *New England Power Pool and USGen New England, Inc.*, 92 FERC ¶61,020 at 61,041 (2000). (Emphasis added.) In 2003, the Commission approved a revised Schedule 16 rate that was not based on generator specific cost information but instead on historic actual payments made to generators during a certain period. *New England Power Pool*, 102 FERC ¶61,176 at P 23 (2003) (emphasis added).

process; and (3) similar information about generators in New England was not readily available.⁵⁵

A review of the publicly available cost data from the proxy set of generators showed that the average revenue requirement for those units was \$4.20/kVAR-yr. The December 29 Filing included an attachment that showed the data that was used to derive this average rate of the proxy set. Using a two-thirds, one-third blend of the pre- and post-market generation resulted in a weighted-average revenue requirement of \$2.32/kVAR-yr: $((2 * \$1.38) + \$4.20) / 3 = \$2.32$. The ISO and NEPOOL note that the \$2.32 is well below the average revenue requirement of the new generation used in the proxy set.⁵⁶

In addition to the explanation of how the CC rate increase was developed, the December 29 Filing made two additional points that justify the CC rate increase as just and reasonable. First, the CC rate increase was developed to be a practical and efficient way of pricing dynamic reactive power capability for New England.⁵⁷ Schedule 2 already employs a single CC rate for all generators. The increase to the CC rate simply takes that single rate and updates it using relevant publicly available and Commission scrutinized cost data from PJM generators that are similar in vintage, technology, manufacturer and, presumably, in cost structure. By doing so, the

⁵⁵ At one point in their review of potential Schedule 2 Amendments, the ISO and NEPOOL considered updating the CC rate using the AEP methodology applied to a single proxy unit. A sub-group explored this approach with the intention of using the proposed locational installed capacity (“LICAP”) frame unit as the proxy unit. Ultimately, the ISO and NEPOOL decided against using the LICAP frame unit as the proxy unit for developing the CC rate, because the LICAP design for installed capacity payments was abandoned for the Forward Capacity Market for New England. *See Devon Power LLC*, 115 FERC ¶ 61,340, *reh’g denied*, 117 FERC ¶ 61,133 (2006). This change meant that the LICAP frame unit would not be used and that its cost data would not be updated on a regular basis. Additionally, the LICAP frame unit data did not have the level of specificity necessary to fully integrate such data into the AEP methodology.

⁵⁶ The ISO and NEPOOL also note that NYISO pays a reactive power capability rate of approximately \$3.92/kVAR-year, well above the proposed new CC rate of \$2.32/kVAR-year.

⁵⁷ *See, e.g.*, December 29 Filing, Transmittal Letter at 13 & n.24.

ISO, NEPOOL and the Commission avoid inefficient and burdensome proceedings over generator specific cost data for New England. Second, the December 29 Filing made clear that the revised CC rate had the overwhelming support (88%) of NEPOOL,⁵⁸ also evidenced by the fact that only two protests have been filed in connection with the revised rate. This level of support is at least indicative if not determinative of the justness and reasonableness of the Schedule 2 Amendments, including the CC rate increase.⁵⁹

Finally, the ISO and NEPOOL point out the provisions of the Schedule 2 Amendments related to the CC rate have built into them a requirement that the rate cannot be increased pursuant to a Section 205 filing for five years and that the CC rate shall be examined in 2011 for potential changes again in 2012. These features of the proposed CC rate impose discipline on the rate and show the “settlement” nature of the new CC rate and its widespread support.

For the reasons stated above, the Protests regarding the revised CC rate should be rejected.

⁵⁸ *Id.* at 20.

⁵⁹ In approving the Schedule 16 rate in 2003, the Commission stated that “NEPOOL is rightly concerned with incenting generators to provide critical black start service, and NEPOOL's proposal appears to be a practical and efficient solution to this difficulty -- and a solution which, moreover, has been endorsed by a majority of NEPOOL's members.” *New England Power Pool*, 102 FERC ¶61,176 at P 23 (2003) (emphasis added). The same characterization applies to the Schedule 2 Amendments; *see also New England Power Pool and ISO New England Inc.*, 105 FERC ¶61,300 at P 34 (2003) (approving comprehensive transmission expansion cost allocation system for New England as just and reasonable partly based on NEPOOL Participants Committee support and noting that NEPOOL Participants Committee is “broadly representative”).

IV. CONCLUSION

For the reasons stated herein, the ISO and NEPOOL respectfully request that the Commission reject the Protests and accept the December 29 Filing without suspension or hearing.

Respectfully submitted,

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Date: February 5, 2006

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 5th day of February, 2007.

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