123 FERC ¶ 61,129
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

ISO New England Inc. Docket No. ER08-41-001

ORDER DENYING REHEARING

(Issued May 6, 2008)

1. On January 9, 2008, the Interconnection Rights Holders Management Committee (IRH Management Committee), the Maine Public Utilities Commission and the Industrial Energy Consumers Group (collectively, the Maine Parties), and NSTAR Electric Company (NSTAR) requested rehearing of the Commission's December 10, 2007 Order in this proceeding.[1] In that order the Commission accepted proposed values submitted jointly by ISO New England Inc. (ISO-NE) and the New England Power Pool (NEPOOL) (collectively, the Filing Parties) for the Installed Capacity Requirement, Hydro Québec Interconnection Capability Credits (HQICC or HQ Capability Credits), and related parameters for the 2010-2011 Capability year. In this order the Commission denies the requests for rehearing, as discussed below.

I. Background

2. As part of ISO-NE's Forward Capacity Market (FCM) in February 2008, ISO-NE conducted the first Forward Capacity Auction (FCA) for the 2010-2011 Capability Year.[2] In support of the first FCA, the Filing Parties submitted the proposed 2010-2011 Capability Year values for the Installed Capacity Requirement, Local Sourcing Requirement, and Maximum Capacity Limit, all of which are key inputs in the FCA.[3]

[1] *ISO New England Inc.*, 121 FERC ¶ 61,250 (2007) (December 10 Order).

[2] The 2010/2011 Capability Year extends from June 1, 2010, to May 31, 2011.

[3] The Installed Capacity Requirement is the amount of resources needed to meet the New England Control Area reliability requirements of disconnecting non-interruptible customers (i.e., the Loss of Load Expectation) no more than once every ten years. The Local Sourcing Requirement represents the minimum amount of capacity that must be
(continued…)

The Filing Parties also submitted the proposed value for the HQ Capability Credits, which is a key input in the calculation of the Installed Capacity Requirement.

3. Section III.12.9 of Market Rule 1 requires that total tie benefits be calculated using the results of a probabilistic calculation. As explained in the December 10 Order, the Installed Capacity Requirement established by the Filing Parties for the 2010/2011 Capability Year reflects total tie benefits of 1,860 MW, allocated among New England's interconnections with its neighboring Control Areas as follows: 1,400 MW to the HQ Interconnection; 360 MW to the New Brunswick (i.e., Maritimes) interconnections; and 100 MW to the New York interconnections. While the New Brunswick and New York interconnections are allocated a portion of the total tie benefits, the tie benefits associated with the HQ Interconnection are assigned to certain market participants in the form of HQ Capability Credits. Specifically, in accord with prior Commission orders,[4] and as described in section III.12.9.2 of Market Rule 1, HQ Capability Credits are calculated using a "deterministic" methodology that employs forecasted load and capacity for the Québec Control Area and the HQ Interconnection transfer limit.[5] Importantly, the tie benefits for New Brunswick and New York are reduced to reflect HQ Capability Credits: after subtracting the HQ Capability Credit value from the total tie benefits value, the remainder is reallocated proportionally in the same ratio as the tie benefits from the original probabilistic analysis for New York and New Brunswick, resulting in reduced tie benefits from New York and New Brunswick.

4. As detailed in the December 10 Order, in addition to reducing capacity requirements of the Interconnection Rights Holders, the monthly values for HQ Capability Credits can affect the allocation of total tie benefits among the different interconnections between New England and other control areas and, thereby, directly affect the values for Local Sourcing Requirement and Maximum Capacity Limit and the amount of capacity that may be imported from other control areas.

5. In addition to accepting submitted values for the Installed Capacity Requirement, HQ Capability Credits, and related parameters for the 2010/2011 Capability year, the December 10 Order also addressed the concerns of several parties over inconsistencies in

---

electrically located within an import-constrained Load Zone. The Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone to meet the Installed Capacity Requirement.

[4] *ISO New England Inc.*, 118 FERC ¶ 61,157, at P 36 (2007); *New England Power Pool*, 111 FERC ¶ 61,132, at P 19 (2005).

[5] Market Rule 1 § III.12.9.2.

the current approach for tie benefit allocation, noting that there is no tariff rule to resolve this discrepancy between the methodologies for the total tie benefits and for HQ Capability Credits. As such, the December 10 Order supported a stakeholder process and required a July 2008 filing to summarize the results of the stakeholder discussions and outline any proposed changes to the current tie benefit methodology for power years beyond 2010/2011.

II. Requests for Clarification and/or Rehearing and Answer

6. On January 9, 2008, the IRH Management Committee, the Maine Parties, and NSTAR separately requested rehearing of the December 10 Order.

7. In its request, the IRH Management Committee asks the Commission to clarify that the Commission's support for reconsideration of the tie benefit methodology does not (1) mandate or necessarily require a change in the deterministic methodology for calculating HQ Capability Credits; (2) preclude a change in other aspects of ISO-NE's tie benefit methodology; (3) require the adoption of a particular methodology; or (4) require the application of the same methodology to all interconnections with neighboring control areas. Furthermore, the IRH Management Committee asks the Commission to clarify that the December 10 Order should not be construed as denying the Interconnection Rights Holders their long-standing right to receive HQ Capability Credits.[6]

8. The IRH Management Committee contends that the stakeholder process endorsed in the December 10 Order does not necessarily require a change from the deterministic methodology in the calculation of HQ Capability Credits for subsequent years. First, the IRH Management Committee points out that the Commission previously found that the deterministic calculation used to develop the values of the HQ Capability Credits "is consistent with the type of standardized approach envisioned by the Commission."[7] According to the IRH Management Committee, these values were then incorporated in Installed Capacity Requirements accepted by the Commission. Further, the IRH

---

[6] Interconnection Rights Holders are public utilities and non-jurisdictional utilities that have the contractual obligation to pay for the United States portion of the 2,000 MW (nominal) high voltage direct current transmission facilities (Phase I/II facilities) interconnecting the transmission systems operated by ISO-NE and Hydro Québec TransÉnergie and, in turn, hold certain rights, including the right to receive HQ Capability Credits. IRH Management Committee Request for Rehearing at 1.

[7] *Id.* at 8 (quoting *New England Power Pool*, 111 FERC ¶ 61,132, at P 13 (2005)); *see also id.* at 15, 16.

Management Committee states that the deterministic methodology was incorporated into the FCM Settlement Agreement and ISO-NE's Market Rule 1.[8] Second, the IRH Management Committee notes that the total tie benefits for the 2010/2011 Capability Year are less than the total for previous years, a change "wholly unrelated" to the deterministic methodology used to calculate HQ Capability Credits. Third, the IRH Management Committee states that the probabilistic methodology resulted in an increased allocation to the New Brunswick tie (from 200 MW to 360 MW), though the New York tie realized a decrease (from 600 MW to 100 MW). Such "drastically different allocations" are based on ISO-NE's probabilistic calculation of the simultaneous benefit from all three adjoining control areas, not the deterministic methodology.[9]

9. Thus, the IRH Management Committee contends that the December 10 Order does not require the exclusive use of the probabilistic methodology for determining the tie benefits associated with all interconnections. The IRH Management Committee first remarks that the probabilistic method understates the actual reliability benefits. Second, the deterministic method may remain appropriate for calculating the tie benefits for the Phase I/II facilities, because the diversity of resources, and consequently the tie benefits, between the New England and Québec control area are clear.[10] Third, the IRH Management Committee states that the Phase I/II facilities are unique in that only the Interconnection Rights Holders pay for them. Therefore, the IRH Management Committee requests clarification that the December 10 Order requires only a consistent approach, not the same approach, to calculating tie benefits.[11]

10. At the outset, the Maine Parties note that if the total tie benefits were allocated solely on the basis of a probabilistic analysis, the allocation to the individual interconnections would be: 940 MW to Québec; 205 MW to New York; and 715 MW

---

[8] *Id.* at 9 (citing FCM Settlement Agreement § III.B.3(a); *Devon Power LLC*, 115 FERC ¶ 61,340, *order on reh'g*, 117 FERC ¶ 61,333 (2006) (accepting FCM Settlement Agreement); Market Rule 1 § III.12.9).

[9] *Id.* at 17.

[10] *Id.* at 19-20.

[11] *Id.* at 20; *see also id.* at 21-23 (arguing that alternative method should be consistent with Commission's prior HQ Capability Credits orders that note, *inter alia*, benefits of Phase I/II facilities).

(rather than 360 MW) to New Brunswick.[12] They state that under the deterministic method the HQ Capability Credits are valued at 1,400 MW; this value is 460 MW higher than it would be under a probabilistic analysis.

11. The Maine Parties contend that the Commission failed to address whether the reduction of available tie benefits from New Brunswick (from 715 MW to 360 MW) overstates the amount of capacity actually available from Maine and understates the amount of capacity available from New Brunswick (by 355 MW).

12. The Maine Parties also contend that the Commission acted arbitrarily and capriciously by rejecting the proposal of the Maine Public Utilities Commission as having no tariff support,[13] because the reduction of the tie benefits likewise is "not a justifiable tariff based proposal."[14] The Maine Parties recognize that ISO-NE was faced with the problem of reconciling two distinct tariff provisions; namely, to calculate tie benefits using a probabilistic method (under Market Rule 1, section III.12.9) and to calculate the tie benefits over the Hydro Québec Interconnection and the related HQ Capability Credits using a deterministic method (under Market Rule 1, section III.12.9.2).[15] The Maine Parties maintain that ISO-NE's particular manner of reconciling these provisions was not directed by any language in the tariff.

13. The Maine Parties further contend that the Commission's finding that it is "unlikely" that the export constraint will bind is not supported by the evidence. Moreover, the Maine Parties assert that the Commission's acceptance of ISO-NE's conclusion that it is unlikely that the constraint will bind fails to recognize the role that price will play (since the rest of pool and Maine pricing patterns during the auction are

[12] Maine Parties Request for Rehearing at 3 (referring to October 11 Transmittal Letter at 20); *see also id.* at 4.

[13] As described in the December 10 Order, the Maine Parties had advocated a reduction in the Maximum Capacity Limit for the Maine Load Zone to reflect the New Brunswick tie benefits as calculated under the probabilistic methodology (715 MW) rather than the reduced value (360 MW) that reflected the HQ Capability Credits. The Maine Parties had expressed concern that the reduction in tie benefits may prevent the Maine export constraint from binding, which would directly impact the price of capacity in Maine. December 10 Order, 121 FERC ¶ 61,250 at P 48-49.

[14] Maine Parties Request for Rehearing at 13.

[15] *Id.*

impossible to predict). Further, the Maine Parties contend that even if the record supported the Commission's finding, such a finding does not justify allowing distorted inputs that may prevent the FCA from working as intended.

14. Finally, the Maine Parties maintain that the Commission exceeded its jurisdiction in determining the amount of capacity needed to ensure reliability.

15. In its request for rehearing, NSTAR contends that the Commission "blindly accepted a travesty" in accepting Installed Capacity Requirements values that are based on erroneous tie benefits calculations. NSTAR contends that ISO-NE's "ratio methodology" is an "illegitimate approach" to calculating tie benefits, which finds no support in the ISO-NE tariff or the Market Rules.[16] Further, NSTAR explains that in previous years the tie benefits values were derived from market participant compromises, based on probabilistic and deterministic studies, rather than the ratio methodology.

16. NSTAR maintains that the Commission erred by rejecting NSTAR's proposed tie benefit methodology, which it contends is consistent with the Market Rules and Commission policy. NSTAR states that the Commission never addressed nor reconciled the fact that ISO-NE's initial interpretation of the Market Rules was identical to NSTAR's and the fact that, during stakeholder discussions, ISO-NE changed its initial proposal to incorporate a ratio methodology.

17. NSTAR also maintains that the Commission erred in accepting the Filing Parties' change in the tie benefits methodology without requiring a filing under section 205 of the Federal Power Act (FPA).[17] Further, NSTAR states that the Commission erred by not investigating or reconciling the discrepancy in the values between the 2010/2011 Study and the 2003 NEPOOL Tie Benefits Study (2003 Study),[18] which ISO-NE contends are based on the same methodology and same assumptions of unconstrained and "at criterion" conditions.[19] Thus, NSTAR reiterates that the tie benefits value calculated

---

[16] NSTAR Request for Rehearing at 3-4, 5.

[17] 16 U.S.C. § 824d (2000 & Supp. V 2005).

[18] NEPOOL March 23, 2004 Filing, Attachment 6 (Feb. 26, 2003), Docket No. ER04-670-000 (2003 Study).

[19] The 2003 Study provides:

> In this scenario, the loads of Maritimes, Hydro Quebec, Ontario, and New York control area are adjusted so that the reserve margins are <u>at their planning criteria</u>. For Maritimes, Hydro Quebec and New York control

(continued…)

according to the probabilistic method using non-constrained “at criterion” conditions renders a total of 1,860 MW for the 2010/2011 Study, which falls below the 2,980 MW tie benefits value calculated according to the 2003 Study conditions and methodology.[20]

18. Lastly, NSTAR claims that the Commission erred by directing a stakeholder process to reinvestigate the currently established tie benefits methodology.

19. On January 24, 2008, ISO-NE submitted an answer addressing certain issues raised by the IRH Management Committee.

III. Discussion

20. Rule 213(a)(2) of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2007), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We are not persuaded to accept ISO-NE’s answer and will, therefore, reject it.

21. We deny requests for rehearing and grant the request for clarification as discussed below.

A. IRH Management Committee’s Requests

22. The IRH Management Committee requests clarification or, alternatively, rehearing of certain points of the December 10 Order; namely, that the order does not require (1) any change from a deterministic method in the calculation of HQ Capability Credits, (2) the exclusive use of a probabilistic method for calculating tie benefits associated with all interconnections, or (3) the adoption of any particular method for all interconnections. Further, the IRH Management Committee requests the same as to whether the

---

> areas, the required reserve margins are based on their latest *NPCC Triennial Review of Resource Adequacy*. For Ontario, the weekly required reserve margins specified in *IMO 18-Month Outlook* are used.

2003 Study at 4 (emphasis added). NSTAR maintains that ISO-NE redefined the “at criterion” to mean that all control areas were assumed to have met the same reliability criteria rather than the more conservative planning criteria. NSTAR Request for Rehearing at 14.

[20] NSTAR Request for Rehearing at 15.

December 10 Order should be construed as denying the IRH Management Committee of its right to receive HQ Capability Credits in exchange for its commitment to pay for the Phase I/II facilities, or overturning Commission orders affirming those rights.

23. The Commission here clarifies that the December 10 Order does not specifically require that ISO-NE change its use of a deterministic method to calculate the values of the HQ Capability Credits, nor does the order necessarily require the exclusive use of the probabilistic method for calculating tie benefits associated with all interconnections. The December 10 Order does not advocate the adoption of any particular method nor the application of the same method to all interconnections, but rather encourages ISO-NE and its stakeholders to consider a long-term methodology for determining and allocating tie benefits that is consistent among all interconnections with external control areas, consistent with the locational aspect of the FCM, and which does not reflect an overly aggressive estimate of tie benefits based on unrealistic assumptions, i.e., that the total New England tie benefits do not exceed the amount determined probabilistically.[21] As we stated in that order, the Commission would support a stakeholder process that would revisit the tie benefits methodology, including whether the deterministic approach for calculating HQ Capability Credits remains the most efficient approach under a locational capacity construct like FCM.[22] Notwithstanding any guidance that the December 10 Order may have provided, the order does not tacitly pre-judge the outcome of such a stakeholder process, nor does the order preclude change in other aspects of the tie benefits methodology.

B. <u>The Maine Parties' Request</u>

24. The Maine Parties reiterate on rehearing the issues they raised in their initial protest.[23] In the December 10 Order, the Commission noted the Maine Parties' contention that the reduction of New Brunswick tie benefits from 715 MW to 360 MW overstates available capacity from Maine and, conversely, understates available capacity from New Brunswick.[24] The Commission addressed ISO-NE's proposed calculations and allocations—among which the distribution of tie benefits to New Brunswick is to be counted—and concluded that the Filing Parties' proposed methodology was consistent

---

[21] December 10 Order, 121 FERC ¶ 61,250 at P 90.

[22] *Id.* P 75.

[23] *Id.* P 48-49, 80.

[24] *Id.* P 48.

with the applicable tariff provisions and would produce just and reasonable rates in the capacity market.[25] While ISO-NE's proposed methodology does not preclude the existence of other just and reasonable methodologies,[26] the Commission found that ISO-NE's proposal was just and reasonable.

25. As discussed above, the Commission did not merely reject the Maine Parties' proposal out of hand; rather, the December 10 Order found that the Filing Parties had satisfied the tariff requirements and that the proposed methodology would produce just and reasonable rates.[27] The Maine Parties did not demonstrate that the Filing Parties' proposed methodology was unjust and unreasonable. Further, the Commission found that the Maine Parties' proposal that the total tie benefits be allocated solely on the basis of a probabilistic analysis would have ISO-NE ignore section III.12.9.2 of Market Rule 1, for which the Maine Parties provided no tariff support.[28] Notably, the ISO-NE proposal took into account and attempted to reconcile sections III.12.9 and III.12.9.2 of Market Rule 1. In fact, the Maine Parties recognize that ISO-NE was faced with the problem of reconciling two distinct tariff provisions that the tariff does not specifically address how to reconcile.[29] Accordingly, because of the foregoing—and because the Maine Parties have proffered no tariff support to the contrary—the Commission rejected the Maine Parties' requested short-term relief; namely, a reduction in the Maximum Capacity Limit (a key input in the FCA).[30] In doing so, the Commission noted that the purpose of the FCA is not to ensure that Maine remains an export-constrained zone but to procure the resources necessary to satisfy the Installed Capacity Requirement in the New England region, subject to the applicable transmission and other constraints.[31]

---

[25] *Id.* P 53.

[26] *Id.* P 53 & n.31.

[27] *Id.* P 53-54, 68-69.

[28] *Id.* P 53-54. Moreover, the Maine Parties note the two distinct tariff sections that ISO-NE proposed to reconcile in the filing underlying this request for rehearing. Maine Parties Request for Rehearing at 13-14.

[29] Maine Parties Request for Rehearing at 13.

[30] December 10 Order, 121 FERC ¶ 61,250 at P 53-54.

[31] *Id*. P 54.

26. Based on ISO-NE's representations and in light of the Maine Parties' paucity of evidence to the contrary, the Commission agreed that it appeared unlikely that the Maine export constraint would bind.[32] The December 10 Order noted that the Maine export-constraint was unlikely to bind due to the large excess of capacity in the rest of pool, relatively small capacity excess in Maine, and the existence of a price floor applicable to all zones.[33] If such export constraint did bind—that is, if more capacity was desired for export from Maine than the transmission system could provide (taking into account transmission capacity set aside for tie benefits)—separate zones would have been designated for export-constrained zones like Maine and, possibly, capacity prices in Maine could have been less than the Rest-of-Pool zone.[34] ISO-NE's judgment was proven accurate, for there was a significant excess of existing and new capacity in the February 2008 FCA. Moreover, this excess capacity prevented the modeled constraint from binding and resulted in the lowest possible capacity price; capacity prices reached the $4.50 per kW-month price floor throughout the region. As such, the relatively lower Maximum Capacity Limit value that reflected the deterministic HQ Capability Credits value did not expose Maine to a higher capacity price.

27. The Maine Parties maintain that even if the Commission's finding is supportable by record evidence, such a finding does not justify allowing distorted inputs that may affect the FCA. The Commission reiterates that the Maine Parties' ongoing concerns and critiques with ISO-NE's current tie benefits methodology are appropriately addressed in a stakeholder process.

28. Lastly, with respect to the Maine Parties' position that the Commission exceeded its jurisdiction, the Commission explained in the December 10 Order and here maintains that it has jurisdiction over the Installed Capacity Requirement because it is a component of jurisdictional wholesale rates.[35]

---

[32] *Id.* P 51-52, 54; *see also id.* P 49, 50.

[33] *Id.* P 50, 54.

[34] *Id.* P 51-52.

[35] *Id.* P 81 (citing *ISO New England Inc.*, 121 FERC ¶ 61,125, at P 33-39 (2007)); *Maine Pub. Util. Comm'n v. FERC*, No. 06-1403, Slip Op. at 26-28 (D.C. Cir. Mar. 28, 2008) (affirming Commission jurisdiction over FCM).

C. NSTAR's Request

29. NSTAR reiterates on rehearing the issues it raised in its initial protest.[36] NSTAR maintains that the December 10 Order errs by rejecting NSTAR's proposal to combine (rather than net out) the HQ tie benefits calculated deterministically with the probabilistic calculations for the New York and New Brunswick tie benefits. In support, NSTAR points out that ISO-NE's initial interpretation of the tariff provisions and proposed tie benefits methodology was the same as NSTAR's. As we said above, the Commission found ISO-NE's proposed methodology to be just and reasonable;[37] however, this does not preclude the existence of other just and reasonable methodologies.[38] Further, the fact that ISO-NE previously in stakeholder discussions may have endorsed an understanding of the relevant tariff provisions and a tie benefits methodology that was the same as what NSTAR is now proposing does not necessarily undermine the justness and reasonableness of ISO-NE's current proposal or the fact that the current proposal is in line with how ISO-NE had been undertaking the calculations for Installed Capacity Requirements and other related values in past years.[39] As the Commission explained in the December 10 Order,

> we have consistently accepted the calculation of total New England control area tie benefits on a probabilistic basis, and the allocation of the tie benefits over the Hydro Québec interconnection on a deterministic basis, with a net reduction of tie benefits over the New York and New Brunswick interconnections to retain the total tie benefits as calculated under a probabilistic methodology.[[40]]

---

[36] *Id.* P 55-61.

[37] *Id.* P 68-69.

[38] *See supra* P 24 & n.26.

[39] December 10 Order, 121 FERC ¶ 61,250 at P 70-72.

[40] *Id.* P 70 & n.38 (citing *ISO New England lnc.*, 119 FERC ¶ 61,161 (2007) (accepting proposed 2007-2008 Capability Year Installed Capacity Requirements); *ISO New England Inc.*, 115 FERC ¶ 61,149 (2006) (accepting proposed 2006-2007 Capability Year Installed Capacity Requirements); *ISO New England Inc.*, 111 FERC ¶ 61,185, *reh'g denied*, 112 FERC ¶ 61,254 (2005), *appealed on jurisdictional grounds sub nom. Conn. Dep't of Pub. Util. Control v. FERC*, 484 F.3d 558 (D.C. Cir. 2007), *petition for reh'g en banc denied*, No. 05-1411, 2007 US. App. LEXIS 17020 (D.C. Cir. July 13,

(continued…)

More importantly, however, the Commission pointed out that NSTAR's alternative proposal ignores Commission directives and tariff requirements and results in a double-counting of a portion of the New England tie benefits by failing to deduct the 1,400 MW of tie benefits attributed to HQ Capability Credits.[41]

30. NSTAR contends that the Commission erred in accepting a change to the tie benefits methodology without requiring a filing under section 205 of the FPA. The Commission noted that the Filing Parties contended that their proposal implemented the filed rate and that, while there may be other just and reasonable tie benefits allocation methods, such would require adjusting the filed rate.[42] The Commission continues to agree that the Filing Parties' proposed methodology is consistent with Market Rule 1 and Commission precedent.[43]

31. NSTAR reiterates that a change in the "at criterion" has produced the difference in values between the 2003 Study (2,980 MW) and the instant 2010/2011 study (1,860 MW).[44] In turn, the Commission revisits and reiterates our discussion in the December 10 Order where we addressed this claim and found ISO-NE's values to be just and reasonable.

> The Filing Parties' "at criteria" assumption reflecting a Loss of Load Expectation included in the instant filing is just and reasonable because it models potential transmission constraints on neighboring control areas. The Filing Parties' approach recognizes that the exact system conditions of neighboring control areas are unknown three years in advance and therefore builds a conservative margin of safety into its calculation of tie benefits available. We find this to be a reasonable approach.

2007) (unpublished decision) (accepting proposed 2005-2006 Capability Year Installed Capacity Requirements); *see also ISO New England Inc.*, 111 FERC ¶ 61,185 at P 4 n.4 (accepting ISO-NE's probabilistic methodology)).

[41] *Id.* P 71-72.

[42] *Id.* P 44, 45.

[43] *Id.* P 68-69, 70.

[44] *Id.* P 61, 66; *see also supra* note 19 and accompanying text.

> Further, while we recognize that the Filing Parties have not always calculated tie benefits under the "at-criteria" assumption reflecting a Loss of Load Expectation in neighboring control areas, we note that the Filing Parties are not required by Market Rule 1 to calculate tie benefits assuming no transmission constraints. Our standard of review of the Filing Parties' proposal is whether they have offered a methodology that has provided for just and reasonable rates in the capacity market and is consistent with the applicable tariff provisions. We find this methodology to be just and reasonable and consistent with the ISO-NE Tariff.[[45]]

32. NSTAR lastly contends that the Commission erred by directing a stakeholder process. In the December 10 Order, the Commission noted that several parties were advocating "a stakeholder process to reconsider the current methodologies for determining and allocating tie benefits," as well as the Filing Parties' "willingness to entertain any prospective proposals for market rules changes within the stakeholder process."[46] The Commission expressed "support" for a stakeholder process that would "revisit the tie benefits methodology"; the Commission encouraged ISO-NE and its stakeholders to "consider a long-term methodology for determining and allocating tie benefits."[47] However, the Commission did not direct that ISO-NE conduct a stakeholder process.

33. Accordingly, the Commission denies the three requests for rehearing, grants the IRH Management Committee's request for clarification, and encourages a stakeholder process that revisits the tie benefit methodology and, should there be such a process, requires ISO-NE in its July 2008 filing to summarize the results of the stakeholder discussions and outline any proposed changes to the tie benefit methodology to be in effect for the December 2008 FCA.

---

[45] December 10 Order, 121 FERC ¶ 61,250 at P 73-74.

[46] *Id.* P 90, 46.

[47] *Id.* P 75, 90.

<u>The Commission orders</u>:

The requests for rehearing are hereby denied and clarification granted, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.