121 FERC ¶ 61,250
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. and New England Power Pool Participants Committee — Docket No. ER08-41-000

ORDER ACCEPTING PROPOSED INSTALLED CAPACITY REQUIREMENT, HYDRO QUEBEC INTERCONNECTION CAPABILITY CREDITS, AND RELATED VALUES

(Issued December 10, 2007)

1. On October 11, 2007, ISO New England Inc. (ISO-NE) and the New England Power Pool (NEPOOL) (together, the Filing Parties) jointly filed proposed values for the Installed Capacity Requirement, Hydro Québec Interconnection Capability Credits (HQ Capability Credits), and related parameters for the 2010-2011 Capability Year. These 2010-2011 Capability Year values would be used as part of the first auction under New England's Forward Capacity Market (FCM), which will be held in February 2008. In this order, we accept the Filing Parties' proposed values for the Installed Capacity Requirement, HQ Capability Credits, and related parameters, effective December 11, 2007, as discussed below.

I. Background and Summary of Filing

2. As part of the FCM, ISO-NE is preparing to conduct the first Forward Capacity Auction (FCA) for the 2010-2011 Capability Year,[1] to be held in February 2008. The February 2008 FCA will satisfy the capacity-related reliability obligations of all New England market participants within ISO-NE's control area. In this filing, the Filing Parties submit the 2010-2011 Capability Year values for the Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit, all of which are key inputs in the FCA. The Filing Parties also submit the proposed value for HQ Capability Credits, which is a key input in the calculation of the Installed Capacity Requirement.

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

A. Installed Capacity Requirement

3. The Installed Capacity Requirement is a measure of the installed resources that are projected to be necessary to meet reliability standards in light of total forecasted load requirements for the New England Control Area and to maintain sufficient reserve capacity to meet reliability standards. Specifically, 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 methodology for calculating the Installed Capacity Requirement is set forth in section III.12 of Market Rule 1.

4. The Installed Capacity Requirement for the 2010-2011 Capability Year is the amount of installed capacity to be procured in the FCA that will be held in February 2008. Consistent with prior years, the Filing Parties state that the values for this year's filing are based on three essential components: load forecast, unit availability, and tie benefits. Further, the Filing Parties state that the methodologies for determining projected load, outage rates, and tie benefits are the same as those used in previous years' filings, adjusted due to the need under the new FCM to project the Installed Capacity Requirement three years in advance.

1. Assumptions

a. Load Forecast

5. The Filing Parties state that the forecasted peak loads of the entire New England Control Area for the 2010-2011 Capability Year were used to develop the corresponding annual Installed Capacity Requirement detailed in this filing. ISO-NE's ten-year load forecast, covering the years 2007 through 2016, was published in April 2007 in the ISO-NE's "2007-2016 Forecast Report of Capacity, Energy, Loads, and Transmission" (2007 CELT Forecast). The Filing Parties aver that the 2007 CELT Forecast was developed by ISO-NE using the same methodology used previously to develop Commission-approved Installed Capacity Requirement values,[2] reflecting economic and demographic assumptions as reviewed and agreed to by the NEPOOL Load Forecast Committee.

---

[2] Filing Parties Filing at 10 (citing, *e.g., ISO New England Inc.*, 119 FERC ¶ 61,161 (2007) (accepting ISO-NE-proposed Installed Capacity Requirements for the 2007-2008 Power Year); *ISO New England Inc.*, 115 FERC ¶ 61,149 (2006) (accepting ISO-NE-proposed Installed Capacity Requirements for the 2006-2007 Power Year)).

6. The Filing Parties state that the projected New England Control Area 50/50 peak load[3] (summer) for the 2010-2011 Capability Year is 29,035 MW, representing a compound annual growth rate of 2.0 percent from the forecasted 50/50 peak load of 27,360 MW for the summer of 2007. The corresponding 90/10 peak load for the 2010-2011 Capability Year is 31,035 MW, representing a compound annual growth rate of 2.1 percent from the forecasted 90/10 peak load of 29,160 MW for the summer of 2007. The forecasted net annual energy for 2007 and 2010 is 132,615,000 megawatt hours (MWh) and 137,235,000 MWh, respectively, and the corresponding energy growth for the calendar year 2007 through 2010 is forecasted to be at a compound annual growth rate of 1.1 percent.

b. Resource Capacity Ratings

7. The Filing Parties state that the 2010-2011 Installed Capacity Requirement is based on capacity ratings of Existing Resources as of April 30, 2007, i.e., no new capacity resource additions or attritions following that date are assumed. Potential new capacity resources are not included in the calculations since it was not known at the time the Installed Capacity Requirement was developed which resources would qualify to participate or clear in the 2010-2011 FCA. Similarly, no resource attritions are assumed because such assumptions would be based on De-listed Capacity Resources from the previous FCA, and there have been no prior FCAs.

c. Unit Availability

8. The Filing Parties state that consistent with the 2007-2008 Installed Capacity Requirement approved by the Commission, the proposed 2010-2011 Installed Capacity Requirement reflects unit availability as measured by the Equivalent Demand Forced Outage Rate (i.e., EFORd) based on performance over the prior five-year period.[4] The Filing Parties explain that the modeling of unit availability reflects projected scheduled maintenance and forced outages. Individual generating unit maintenance assumptions are based on each unit's historical five-year average of scheduled maintenance or North American Electric Reliability Corporation (NERC) average scheduled maintenance data for the same class of unit, if five-year average data are not available. The Filing Parties

[3] The 50/50 peak load figure implies that this value has a 50 percent chance of being exceeded; a 90/10 peak load implies that this value has a 10 percent chance of being exceeded.

[4] The EFORd is the portion of time a unit is in demand but unavailable due to forced outages. *See* Market Rule 1 § III.1.3.2.

state that individual generating unit forced outage assumptions are based on the unit's historical forced outage data or NERC average data for the same class of unit, while demand response availability assumptions are based on 2006 actual performance.

d. **Tie Benefits**

9. The Filing Parties state that New England's Commission-approved method for establishing the Installed Capacity Requirement requires certain assumptions regarding the tie benefits value to be used as an input in the formula. Specifically, the Filing Parties explain that tie benefits from neighboring control areas reduce the Installed Capacity Requirement and thus the need to buy capacity within New England. The tie benefits from neighboring control areas reflect the amount of emergency assistance that New England could rely on, without jeopardizing reliability in New England or its neighboring control areas, in the event of a capacity shortage in New England.

10. The Filing Parties explain that tie benefits from neighboring Control Areas are used as an input assumption in the calculations of the Installed Capacity Requirement, Maximum Capacity Limit, and Local Sourcing Requirements for the 2010-2011 Capability Year. The Filing Parties state that section III.12.9 of Market Rule 1 requires that total tie benefits be calculated using the results of a probabilistic calculation that determines the Loss of Load Expectation of the New England system on an isolated basis (excluding connections with other control areas) and on an interconnected basis (including all existing connections with directly connected control areas). The difference between the two calculations is then translated into capacity-equivalent MW, which represents the total tie benefits to New England. The Filing Parties note that the probabilistic methodology has been applied over the past several years to develop assumptions regarding total tie benefits that were used in developing other Installed Capacity Requirement values that have been filed with and accepted by the Commission.[5]

11. The Filing Parties contend that the Installed Capacity Requirement for the 2010-2011 Capability Year proposed by ISO-NE and supported by NEPOOL in this filing reflects the total tie benefits calculated in accordance with the applicable provisions of the ISO-NE Tariff and prior Commission directives.[6] The Installed Capacity

---

[5] *See, e.g.*, *ISO New England Inc.*, 111 FERC ¶ 61,185, at P 4 n.4 (2005) (accepting ISO-NE's probabilistic methodology).

[6] The Filing Parties note that under sections III.8.1 and III.12.9 of Market Rule 1 (Annual Installed Capacity Requirement), ISO-NE calculates the Installed Capacity Requirement each Capability Year and, after consultation with stakeholders, ISO-NE must file the Installed Capacity Requirement with the Commission pursuant to section

(continued…)

Requirement established here 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. The Filing Parties note that, 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.

e. **<u>HQ Capability Credits</u>**

12. HQ Capability Credits, also known as HQICCs, are capacity credits that are allocated to the Interconnection Rights Holders, which are entities that hold certain rights over the HQ Interconnection. The Filing Parties contend that, in compliance with prior Commission orders,[7] and as described in section III.12.9 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.[8] The Filing Parties state that 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. Specifically, 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

---

205 of the Federal Power Act, 16 U.S.C. § 824d (2000). *See, e.g., ISO New England Inc.*, 111 FERC ¶ 61,185, *order on reh'*g, 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, 2007) (unpublished decision) (accepting proposed 2005-2006 Capability Year Installed Capacity Requirements). In support of the proposed HQ Capability Credit methodology, the Filing Parties point to examples of Commission directives regarding the methodology for establishing the value of HQ Capability Credits. *E.g., ISO New England Inc.*, 118 FERC ¶ 61,157, *order on reh'g*, 120 FERC ¶ 61,234 (2007); *New England Power Pool*, 104 FERC ¶ 61,204 (2003).

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

[8] Market Rule 1 § III.12.9.2.

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.

13. The Filing Parties note that the Restated NEPOOL Agreement previously required that HQ Capability Credit values be established every Capability Year, with the Firm Energy Contract between certain Interconnection Rights Holders and Hydro Québec providing the valuation of the HQ Capability Credits. During the term of the Firm Energy Contract, the HQ Interconnection was treated for capacity purposes as equivalent to a generator in New England by assigning the "equivalent capacity" value of the Firm Energy Contract to the Interconnection Rights Holders as HQ Capability Credits. Each Interconnection Rights Holder used its HQ Capability Credits to satisfy its installed capacity requirement. The Filing Parties note that after the Firm Energy Contract expired on August 31, 2001, disputes arose over how to establish the value of HQ Capability Credits.

14. The Filing Parties state that pursuant to the Commission's April 30, 2003 Order,[9] ISO-NE must file the monthly Installed Capacity Requirement and HQ Capability Credit values established for each Capability Year. They note that the April 30, 2003 Order was one of a series of orders issued by the Commission addressing disagreements between ISO-NE, Interconnection Rights Holders, and other Market Participants regarding how to calculate monthly HQ Capability Credit values. For example, disputes concerning HQ Capability Credit values for the 2001-2002 Capability Year were resolved in the First HQ Capability Credits Docket,[10] disputes concerning the 2002-2003 Capability Year in the Second HQ Capability Credits Docket,[11] and disputes concerning the 2003-2004

[9] *NSTAR Elec. & Gas Corp. v. New England Power Pool*, 103 FERC ¶ 61,093, at P 23 (2003) (April 30, 2003 Order).

[10] The First HQ Capability Credits Docket was resolved in *PG&E National Energy Group v. ISO New England*, 99 FERC ¶ 61,187 (First HQ Capability Credits Order), *order on reh'g*, 100 FERC ¶ 61,227 (2002) (First HQ Capability Credits Order on Rehearing).

[11] The Second HQ Capability Credits Docket was resolved in *NSTAR Elec. & Gas Corp. v. New England Power Pool*, 102 FERC ¶ 61,107, *order on reh'g*, 103 FERC ¶ 61,093 (2003).

Capability Year were resolved in the Third[12] and Fourth[13] HQ Capability Credits Dockets. The Filing Parties state that although disputes in the HQ Capability Credits Dockets did not directly concern the Installed Capacity Requirement established for those Capability Years, some of the Commission orders in the HQ Capability Credits Dockets have provided direction pertinent to the establishment of Installed Capacity Requirement values. For example, the Filing Parties note that in the First HQ Capability Credits Docket the Commission directed that, starting with the 2002-2003 Capability Year, monthly Installed Capacity Requirements are to be calculated to reflect the actual reliability benefits associated with the HQ Interconnection and generation resources in Hydro Québec as reflected in the established monthly HQ Capability Credit values.[14] Further, in the Second HQ Capability Credits Docket, the Commission provided that HQ Capability Credit values should be established based on availability of generating capacity from Québec that can be accessed through the HQ Interconnection, rather than based on New England's need for that potential emergency assistance by NEPOOL.[15]

15. Citing a prior Commission order that accepted the HQ Capability Credit values for a prior Capability Year,[16] the Filing Parties note that the Commission has required the use of a deterministic approach for developing HQ Capability Credit values.

16. The Filing Parties note that prior to the 2007-2008 Capability Year, the HQ Capability Credit values were the result of separate Commission proceedings to set the yearly credit and additional proceedings to determine whether the Interconnection Rights Holders should be given installed capacity credits. The Forward Capacity Market Settlement Agreement fixes HQ Capability Credit values during the period from December 1, 2006, through May 31, 2010 (Transition Period), at 1,200 MW for March through November and at 0 MW for December through February. The Filing Parties

---

[12] *PG&E National Energy Group v. New England Power Pool*, 103 FERC ¶ 61,112; *see also* April 30, 2003 Order, 103 FERC ¶ 61,093 (2003).

[13] *New England Power Pool*, 104 FERC ¶ 61,204 (2003) (requiring the filing of HQ Capability Credit values for the 2003-2004 Capability Year by December 30, 2003).

[14] *PG&E National*, 100 FERC ¶ 61,227, at P 24.

[15] April 30, 2003 Order, 103 FERC ¶ 61,093, at P 5, 13.

[16] *See New England Power Pool*, 111 FERC ¶ 61,132, at P 19 (2005).

state that, pursuant to the FCM Settlement Agreement, ISO-NE calculates prospective HQ Capability Credit values for use in the FCAs, beginning with the 2010-2011 Capability Year values in the instant filing, for use in the February 2008 auction.

17. Importantly, the Filing Parties state that in addition to reducing capacity requirements for Interconnection Rights Holders, under the FCM the treatment of HQ Capability Credits can affect the allocation of total tie benefits among the different interconnections between New England and other control areas and, consequently, directly affect the values for Local Sourcing Requirement and Maximum Capacity Limit and the amount of external capacity imports allowed to participate in the FCA. In addition, as discussed elsewhere in this order, the level of HQ Capability Credits established using this deterministic methodology can also affect the tie benefits available to be shared by all New England consumers to the extent that the full value of the HQ Capability Credits is deducted from total tie benefits that are available to be allocated to the remaining external ties.

18. The Filing Parties state that based on its calculations of Capacity Potentially Available for Sales, ISO-NE determined that during the months of June through November 2010, and March through May 2011, there is sufficient surplus capacity in the Hydro Québec Control Area to support 1,400 MW of HQ Capability Credits for these months. During the December 2010 through February 2011 time period, the Filing Parties contend that there may be times when the Québec Control Area would not have surplus capacity and, thus, propose HQ Capability Credits of 0 MW for these three months.

19. The Filing Parties remark that HQ Capability Credit values for the 2010-2011 Capability Year have increased to 1,400 MW compared to 1,200 MW for the filed HQ Capability Credit values currently accepted by the Commission for use during the FCM Transition Period. They explain that the 1,200 MW value has been used historically because PJM Interconnection, L.L.C. (PJM) and the New York Independent System Operator, Inc. (NYISO) have no obligation to support any contingency loss in New England that is larger than their largest contingency loss. Previously, 1,200 MW was the largest contingency loss for each of these systems during most of the peak load conditions, and imports over the HQ Interconnection were limited to 1,200 MW to observe this loss of source contingency limit.

20. The Filing Parties state that recent loss of source studies conducted by PJM and NYISO demonstrate that the loss of an import at 1,400 MW over the HQ Interconnection has approximately the same negative impact as the outage of the largest contingency that may occur in the PJM and NYISO regions. As a result, under most high load conditions, New England may be able to import 1,400 MW over the HQ Interconnection. The Filing Parties note that while the 1,200 MW limit still may be applied during real-time

operations when PJM or NYISO determine that they are not able to support a higher limit, for purposes of the FCM, ISO-NE believes that 1,400 MW is an appropriate assumption for emergency imports over the HQ Interconnection.

B. Local Sourcing Requirement and Maximum Capacity Limit

21. The Filing Parties state that the Local Sourcing Requirements and Maximum Capacity Limits were not addressed in pre-FCM Installed Capacity Requirements filings. However, they note that under the FCM, ISO-NE must also calculate Local Sourcing Requirements and Maximum Capacity Limits to be used, if necessary, in each FCA. A Local Sourcing Requirement is "the minimum amount of capacity that must be electrically located within an import-constrained Load Zone"; a 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]."[17] The Filing Parties note that the general purpose of Local Sourcing Requirements and Maximum Capacity Limits is to ensure that capacity resources are geographically distributed within the New England Control Area in a manner that helps to ensure that capacity is located where it is needed. The Filing Parties state that for the 2010-2011 Capability Year, ISO-NE calculated the Local Sourcing Requirements for Connecticut and NEMA/Boston Load Zones and the Maximum Capacity Limit for the Maine Load Zone. The Filing Parties note that these values were calculated using the same assumptions of forecasted load and resources as those used in the calculation of the Installed Capacity Requirement for the 2010-2011 Capability Year.

Allocation of Tie Benefits

22. The Filing Parties state that to model Local Sourcing Requirements and Maximum Capacity Limits, and to calculate the amount of capacity that may be purchased over each tie in the FCA, it is necessary to allocate the total tie benefits value among each of the interconnections between the New England Control Area and other control areas. They note that the proposed Local Sourcing Requirement and Maximum Capacity Limit values reflect the tie benefit allocation methodology that is specified in sections III.12.9.1 and III.12.9.2 of Market Rule 1.[18]

---

[17] Market Rule 1 § III.13.

[18] Section III.12.9.2 of Market Rule 1 provides that ISO-NE shall calculate the MW value of the tie benefits over the HQ Interconnection and determine the HQ Capability Credits using a deterministic methodology.

23. As stated above, the total tie benefits are allocated among the external ties in a manner that first deducts the full amount of the deterministically-calculated HQ Capability Credits from the total tie benefits. The remainder of the total tie benefits is then allocated between the New Brunswick and New York ties based on the results of probabilistic engineering studies. The Filing Parties state that if the total tie benefits for the 2010-2011 Capability Year were allocated solely on the basis of the probabilistic analysis, the allocation to the individual interconnections would be approximately 940 MW to Québec, 715 MW to New Brunswick, and 205 MW to New York, a total of 1,860 MW.

24. The Filing Parties state that this filing for the 2010-2011 Capability Year reflects the deduction of the 1,400 MW of HQ Capability Credits from the 1,860 MW of total tie benefits, leaving 460 MW of tie benefits to be allocated between the New Brunswick and New York ties on a proportional basis. The remaining 460 MW is allocated to the New Brunswick and New York ties based on the ratio of their individual Control Area tie benefits to the sum of their tie benefits calculated from the probabilistic simulation that produced the total tie benefits of 1,860 MW. Thus, the New Brunswick ties would be allocated 360 MW and the New York ties would be allocated 100 MW.

25. The Filing Parties contend that allocating the remainder of the total tie benefits this way preserves the calculated contribution relationship without artificially over- or under-relying on emergency assistance from one Control Area over the other. They also note that this approach to allocating individual interconnected Control Area tie benefits from the total tie benefits is the same methodology that has been used for the past three years in calculating the filed and Commission-approved Installed Capacity Requirement values for the Capability Years 2005-2006 through 2007-2008. They state that these allocated tie benefits have been used to calculate capacity import limits from each neighboring Control Area during this period.

C. <u>Proposed Values</u>

26. The Filing Parties propose that the Installed Capacity Requirement for the 2010-2011 Capability Year should be 33,705 MW. They note that the 33,705 MW value accounts for tie benefits assumed obtainable from New Brunswick and New York, but it does not reflect a reduction in capacity requirements relating to HQ Capability Credits that are allocated to the Interconnection Rights Holders. Instead, the proposed HQ Capability Credit value of 1,400 MW is applied to reduce the portion of the Installed Capacity Requirement that is allocated to the Interconnection Rights Holders, leaving a net amount of 32,305 MW of capacity to be purchased in the FCA to meet the Installed Capacity Requirement.

27. The Filing Parties propose that the 2010-2011 Capability Year Local Sourcing Requirements for the Connecticut and NEMA/Boston Load Zones should be 7,017 MW

and 2,246 MW, respectively. They propose a Maximum Capacity Limit for the Maine export-constrained Load Zone of 3,855 MW.

D. Development/Stakeholder Process

28. The Filing Parties state that ISO-NE, in consultation with NEPOOL and other interested parties, developed the proposed Installed Capacity Requirement and related values for the 2010-2011 Capability Year through an extensive stakeholder process over a period of ten months. They note that ISO-NE used the methodologies and assumptions for determining the Installed Capacity Requirement and related values that are set out in section III.12 of Market Rule 1, which were approved by the Commission earlier this year.[19] They also state that the methodology and assumptions used to calculate the proposed Installed Capacity Requirement and HQ Capability Credits values are consistent with the approach reflected in the recent capacity requirement values submitted for previous Capability Years.[20]

29. The Filing Parties note that during the stakeholder process, NSTAR advocated the use of a hybrid approach to calculate total tie reliability benefits for New England. They note that NSTAR's proposed approach would combine the results of a deterministic methodology to calculate HQ Capability Credits with the results of a probabilistic methodology to calculate New Brunswick and New York tie benefits. The Filing Parties state that under NSTAR's proposal, the results of these two distinct methods would be summed to produce the total tie benefits value, which would result in an increase of the

[19] *ISO New England Inc.*, 118 FERC ¶ 61,157, *reh'g denied*, 120 FERC ¶ 61,234 (2007) (the ICR Rules Order), *appeal docketed sub nom. Conn. Dep't of Pub. Util. Control v. FERC*, No. 07-1375 (D.C. Cir. Sept. 21, 2007). The Filing Parties note that the appeal challenges the Commission's jurisdiction to approve the Installed Capacity Requirement but does not challenge the actual technical provisions of the market rules reflected in section III.12 of Market Rule 1, which were approved by the Commission in the ICR Rules Order and which were used to calculate the Installed Capacity Requirement and related values that are the subject of this filing.

[20] Citing *ISO New England lnc.*, 119 FERC ¶ 61,161 (2007); *ISO New England lnc.*, 111 FERC ¶ 61,185 (2005) (accepting proposed 2005-2006 Capability Year Installed Capacity Requirements), *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, 2007) (unpublished decision).

total tie benefits by 260 MW above the proposed 1,860 MW for the 2010-2011 Capability Year. The Filing Parties maintain that this proposed hybrid process for calculating total tie benefits was not supported by ISO-NE or stakeholders. Further, ISO-NE believes that the hybrid approach would overstate the total tie benefits available to New England by assuming that the potential capacity available for sales from Québec would be dedicated to serving New England needs, while in reality control areas interconnected with Québec (i.e., New York) would have equal right to expect emergency assistance from the same surplus, thereby increasing the chances of producing erroneous total tie benefit projections. The Filing Parties contend that the hybrid approach also is not consistent with the probabilistic approach employed to derive tie benefit assumptions used to calculate Installed Capacity Requirement values for previous Capability Years reflected in past Commission-approved filings.

30. The Filing Parties remark that in a vote at the August 21, 2007 NEPOOL Reliability Committee meeting, a motion to recommend that the Participants Committee endorse the proposed HQ Capability Credit values for the 2010-2011 Capability Year garnered 93.35 percent support. Similarly, at the same meeting, a motion to recommend that the Participants Committee endorse the ISO-proposed Installed Capacity Requirement, Local Sourcing Requirement, and Maximum Capacity Limit values received 89.55 percent support. Finally, the Filing Parties state that the NEPOOL Participants Committee subsequently voted 77.16 percent in favor to support the ISO-proposed Installed Capacity Requirement and related values at its September 7, 2007 meeting.

E. Requested Effective Date

31. In order to support the February 2008 FCA, the Filing Parties request an effective date 60 days after the date of submission.

II. Notice of Filings and Responsive Pleadings

32. Notice of the Filing Parties' filing was published in the *Federal Register*, 72 Fed. Reg. 60,011 (2007), with interventions and protests due on or before November 1, 2007. Timely motions to intervene were filed by ANP Funding I, LLC and IPA Mill, LLC; BG Energy Merchants, LLC, BG Dighton Power, LLC, Lake Road Generating, L.P., and MASSPOWER; Dominion Resources Services, Inc.; the IRH Management Committee; Millennium Power Partners, L.P.; Casco Bay Energy Company, LLC; Northeast Utilities Service Company on behalf of the NU Companies; and Mirant Energy Trading, LLC, Mirant Canal, LLC, and Mirant Kendall, LLC. The Massachusetts Department of Public Utilities filed a timely notice of intervention.

33. On November 1, 2007, H.Q. Energy Services (U.S.), Inc. (HQUS) and Brookfield Energy Marketing Inc. (BEMI); Long Island Power Authority and its subsidiary, Long

Island Lighting Company d/b/a LIPA (LIPA); Central Vermont Public Service Corporation (Central Vermont); and the Massachusetts Attorney General filed motions to intervene and comments.

34. NSTAR Electric Company (NSTAR) filed a timely motion to intervene and protest. The Maine Public Utilities Commission also filed a timely notice to intervene and, with the Maine Public Advocate and the Industrial Energy Consumers Group (together, the Maine Parties), filed a protest.

35. On November 1, 2007, the Maine Public Advocate filed comments supporting the Protest of the Maine Parties.

36. On November 6, 2007, FirstLight Power Resources Management, LLC, FirstLight Hydro Generating Company, and Mt. Tom Generating Company LLC (collectively, the FirstLight Parties) filed a motion to intervene out-of-time.

37. On November 16, 2007, the IRH Management Committee; the NEPOOL Participants Committee; NSTAR; and ISO-NE filed motions to answer and answers.

38. On November 26, 2007, the Connecticut Department of Public Utility Control filed a motion to intervene out-of-time.

39. On December 3, 2007, NSTAR filed another motion to answer and answer.

III. Discussion

A. Procedural Matters

40. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2007), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding

41. 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 will accept the November 16, 2007 answers of the IRH Management Committee; the NEPOOL Participants Committee; NSTAR; and ISO-NE because they have provided information that assisted us in our decision-making process. We are not persuaded to accept NSTAR's December 3, 2007 answer and will, therefore, reject it.

42. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedures, 18 C.F.R. § 385.214(d) (2007), the Commission will grant the FirstLight Parties' late-filed

motion to intervene and the Connecticut Department of Public Utility Control's late-filed notice of intervention, given their interest in the proceeding and the absence of any undue prejudice or delay.

B. Tie Benefits

43. The Filing Parties state that late in the stakeholder review process some stakeholders expressed a concern with the methodology used to allocate total tie benefits and the impact of the treatment afforded to HQ Capability Credits on the Maximum Capacity Limit for the Maine Load Zone.[21] The Filing Parties explain that the reduction in tie benefits attributed to the New Brunswick and New York AC ties due to the treatment of HQ Capability Credits has been present in past years but was not raised as a concern in the absence of a zonal capacity market. The Filing Parties remark, however, that with the introduction of a zonal capacity market certain stakeholders are concerned that the reduced tie benefits assigned to the New Brunswick tie, which results in an increase in the Maximum Capacity Limit of the Maine Load Zone, could potentially raise the Maine capacity price. Specifically, the Filing Parties conclude that if the tie reliability contributions from the neighboring Control Areas are based on the results of the probabilistic calculation, then the tie benefits assumption would be approximately 715 MW from New Brunswick, in contrast to the 360 MW assigned to New Brunswick after accounting for HQ Capability Credits. The Filing Parties contend that there would be an approximately one-for-one decrease in the Maximum Capacity Limit for each MW increase in tie benefits assigned to the New Brunswick ties.

44. With respect to the allocation of tie benefits, the Filing Parties contend that this filing implements the Commission-approved filed rate. The Filing Parties maintain that the methodology for allocating the remaining tie benefits between New Brunswick and New York was determined to be the most equitable to all load in the region and most consistent with the market rules, given the level of aggregate tie benefits established pursuant to the requirements of the filed rate, by respecting reliability requirements, and with the HQ Capability Credits established in accordance with the filed rate and prior Commission orders.[22]

45. The Filing Parties argue that without the benefit of voluntary changes to the filed rate, which is not modified by this filing and thus not properly raised as an issue, the Commission should not adjust the HQ Capability Credits and the resulting remaining tie benefits that are to be used for the approaching FCA for the 2010-2011 Capability Year.

[21] Filing Parties Filing at 23.

[22] *Id.* at 23-24.

The Filing Parties acknowledge that there may be other just and reasonable means for allocating aggregate tie benefits among the HQ Interconnection and the remaining ties, but not without adjusting the requirements in the filed rate for the establishment of HQ Capability Credits and then providing additional detail in the filed rate based on additional guidance from the Commission.

46. The Filing Parties note that they have expressed a willingness to entertain any prospective proposals for market rules changes within the stakeholder process. Further, they note that without the Commission signaling a desire to entertain a change in how HQ Capability Credits are established and providing guidance on prospective market rules changes that the Commission would like the region to consider, it is unlikely that a more acceptable result will be established. They add that whatever changes might be considered, it is critical to the successful and timely completion of the first FCA that the current filed rate be followed where applicable and that any changes be prospective only. The Filing Parties request that the Commission here limit its rulings on this filing to the narrower issue of whether the Installed Capacity Requirement, HQ Capability Credit, Local Sourcing Requirement, and Maximum Capacity Limit values are consistent with the filed rate and accept them without change or condition. The Filing Parties contend that for any other concerns, the Commission should direct that those concerns be addressed in the stakeholder process.

47. Further, the Filing Parties contend that changing the allocation of total tie benefits will result in only modest changes to the Maximum Capacity Limit for the Maine Load Zone. They state that, to the extent there were a small decrease in a Maximum Capacity Limit, the corresponding effect would be to decrease the potential amount of capacity resources that could be purchased within the export constrained area for the FCA. The Filing Parties contend that based on the existing and new capacity commitments qualified to participate in the first FCA and their characteristics—including imports from New Brunswick, the price collar that is applicable in the first FCA, and the proposed Maine Maximum Capacity Limit—the Filing Parties do not believe that the lower Maximum Capacity Limit that would be associated with higher tie benefits and lower capacity imports from New Brunswick would materially change the results of the first FCA. The Filing Parties state that this may not be true for subsequent auctions.

1. <u>Maine Protest</u>

48. The Maine Parties state that the probabilistic analysis performed by ISO-NE demonstrates that 715 MW of benefits are available from the New Brunswick control area. Thus, they contend that by deducting the deterministically calculated HQ Capability Credits from the total benefits, ISO-NE understates the amount of tie benefits available from New Brunswick by reducing the New Brunswick tie benefit from 715 MW to 360 MW. Thus, ISO-NE understates the amount of capacity available from New

Brunswick by 355 MW. The Maine Parties contend that this understatement of New Brunswick tie benefits correspondingly overstates how much capacity can be delivered from this export constrained zone. The Maine Parties further contend that, because the Filing Parties concede that there is an approximate one-for-one decrease in the Maximum Capacity Limit for each MW increase in tie benefits assigned to the New Brunswick ties, the Maximum Capacity Limit of the Maine Load Zone would be approximately 3,500 MW rather than 3,855 MW if the New Brunswick tie benefits were not "artificially" reduced. The Maine Parties argue that this inflation of deliverable capacity from the Maine Load Zone distorts inputs to the FCA in a way that can affect prices in Maine. They argue that the Filing Parties have no basis for concluding that the higher Maximum Capacity Limit value will have minimal effect on the results of the FCA.

49. The Maine Parties state that the fact that there may not be enough time before the first auction to change the allocation of tie benefits does not justify the potentially "skewed" auction results that may result from the use of such allocation methodology, since the higher Maximum Capacity Limit rather than FCA bids can affect whether the export constraint binds. Simply put, the Maine Parties are concerned that the reduction in tie benefits from New Brunswick may prevent the Maine export constraint from binding,[23] due to the overstatement of available Maine capacity. Whether or not the constraint binds directly impacts the price of capacity in Maine, according to the Maine Parties. Thus, they contend that even if the Commission concludes that there is inadequate time before the first FCA to resolve the relationship of the HQ Capacity Credit calculation with the allocation of tie benefits, the Commission should not approve the proposed Maximum Capacity Limit. As a temporary solution, the Maine Parties request that the Commission direct ISO-NE to reduce the proposed Maximum Capacity Limit to reflect the actual tie benefits available from New Brunswick.

a. ISO-NE Answer

50. In its answer, ISO-NE reiterates its prior position that, for the first FCA, it is unlikely that the Maine Maximum Capacity Limit would bind, even under a lower Maximum Capacity Limit (reflecting the probabilistic calculation of New Brunswick tie benefits).[24] As support, ISO-NE notes the significant pool-wide capacity surplus (even after adjusting for de-list bids) and the relatively small capacity surplus in Maine, along

[23] If the modeled constraint binds, then, due to transmission constraints, the actual demand for Maine's capacity in the FCA exceeds its supply capability.

[24] I.e., 3,517 MW rather than 3,855 MW, reflecting New Brunswick tie benefits of 715 MW.

with the existence of a price floor applicable to all zones.[25] Finally, ISO-NE notes that Maine does not argue that the Maine Maximum Capacity Limit is inconsistent with the Market Rules, but only that the application of the Market Rules may be financially disadvantageous for Maine.

b. Commission Determination

51. At the outset, we recognize that the question of methodology for allocating tie benefits arises out of the terms of the FCM Settlement Agreement (and is applicable for the first time in the 2010-2011 Capability Year), which provide that capacity zones will be determined by ISO-NE based on an identification of transmission limits that may bind in the FCA.[26] If transmission limits are expected to bind, separate capacity zones are designated and separate but simultaneous auctions are held for each zone.[27] Further, section III.A.5 of the FCM Settlement Agreement states that export-constrained zones will be modeled in the FCA. Of note here, the final set of distinct capacity zones will be based on actual FCA results—if a modeled constraint does not bind in the FCA, the price in that zone will be the same as the price for an adjacent capacity zone.[28]

52. In their protest, the Maine Parties contend that because ISO-NE has reduced the tie benefits available from New Brunswick in its model (relative to the probabilistic tie benefits calculation), the export constraint from Maine might not bind, leading to

[25] ISO-NE notes that with existing capacity of approximately 3,398 MW (net of any de-list bids submitted prior to the FCA), and with approximately 175 MW of new resources available to bid below 0.75 times the Cost of New Entry (i.e., CONE)[25] in Maine, there is only a surplus of roughly 61 MW relative to the lower (3,517 MW) Maximum Capacity Limit. As the pool-wide existing capacity exceeds the required purchases for the first FCA, then by the terms of the FCM Settlement, the FCA must drop below 0.8 times the Cost of New Entry.[25] Since all new and existing resources may withdraw during the auction below 0.8 times the Cost of New Entry, ISO-NE notes that it is probable that the Maine Maximum Capacity Limit will not bind.

[26] *See* FCM Settlement Agreement § III.13.2.3.4; *see also* Explanatory Statement in Support of Settlement Agreement of the Settling Parties and Request for Expedited Consideration of Settlement Agreement Resolving All Issues, *Devon Power LLC*, Docket No. ER03-563-000 *et al.* (filed Mar. 6, 2006) (FCM Settlement Agreement); *Devon Power LLC*, 115 FERC ¶ 61,340 (2006) (accepting proposed settlement agreement).

[27] *See ISO New England, Inc.*, 119 FERC ¶ 61,045, at P 45 (2007).

[28] *Id*. P 52.

relatively higher capacity prices in Maine. Under the terms of the FCM Settlement Agreement the capacity price in an export-constrained zone (like Maine) cannot be higher than in the Rest-of-Pool zone.[29] Essentially, the relatively lower New Brunswick tie benefits assumption resulting from the HQ Capability Credit deterministic methodology means that less of Maine's export transmission capacity will be devoted to tie benefits, resulting in "excess" Maine transmission capacity being available for purchase in the FCA. Although ISO-NE has modeled Maine as an export-constrained zone in its November 6, 2007 filing,[30] if the actual demand for Maine capacity does not exceed the Maximum Capacity Limit for the Maine capacity zone (*viz.*, 3,855 MW) in the FCA, then Maine will not remain a separate capacity zone. Under that scenario, capacity prices in Maine would equal those for the rest-of-pool.

53. Our standard of review here is whether the Filing Parties have proposed a methodology consistent with the applicable tariff provisions and that will produce just and reasonable rates in the capacity market. As noted by the Filing Parties, this standard does not preclude the existence of other just and reasonable methodologies.[31] In their proposed calculation of tie benefits in support of the Installed Capacity Requirement, the Filing Parties have attempted to satisfy two distinct areas of the tariff. Specifically, section III.12.9 of Market Rule 1 provides, "The ISO shall calculate tie benefits, using a probabilistic multi-area reliability model." As stated above, the Filing Parties have satisfied this requirement. With respect to the allocation of tie benefits (specifically, regarding the HQ Interconnection), section III.12.9.2 states that "[t]he ISO shall calculate the MW value of the tie benefits over the HQ Interconnection and determine the HQ Capability Credits using a deterministic methodology that uses forecasted load and capacity for the Quebec Control Area and the HQ Interconnection transfer limit as determined by the ISO." The Filing Parties have also satisfied this requirement.

54. Based on their contention, the Maine Parties would have ISO-NE ignore section III.12.9.2 of the tariff insofar as it reduces the modeled tie benefits from New Brunswick. Importantly, the Maine Parties do not contend that ISO-NE has presented a new Installed Capacity Requirement methodology in the instant filing that conflicts with the methodology used in the calculation of Commission-approved Installed Capacity

[29] *See* FCM Settlement Agreement § III.13.2.7.

[30] The November 6, 2007 filing is an informational filing detailing, *inter alia*, the qualifications for the February 2008 FCA and the modeling of Capacity Zones.

[31] For example, the Commission does not have to extend its inquiry into "determining whether a proposed rate schedule is more or less reasonable than alternative rate designs." *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

Requirement values from prior years. Although the tariff does not specifically address how to reconcile section III.12.9 with section III.12.9.2 (i.e., whether ISO-NE should deduct HQ Capability Credits from the total tie benefits value), we find that, as in previous applications of this methodology, the Filing Parties have offered a just and reasonable approach to calculating tie benefits that is consistent with the tariff. We understand that the 2010-2011 Capability Year represents the first time that the capacity market will have a locational basis, allowing for price separation in the capacity zones. We also are aware that tie benefits assumptions may affect those prices, including whether modeled constraints bind in the auction. However, 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. Further, the Filing Parties represent that the Local Sourcing Requirement and Maximum Capacity Limit values were calculated using the same assumptions of forecasted load and resources as in the calculation of the Installed Capacity Requirement for the 2010-2011 Capability Year. As such, and since the request has no tariff support, we reject the Maine Parties' requested short-term relief for the February 2008 auction (i.e., the reduction of the Maximum Capacity Limit). Finally, although the Commission has not approved the November 6 Informational Filing that ISO-NE cites in support of its contention that the Maine Maximum Capacity Limit will not bind for the 2010-2011 Capability Year, we agree with ISO-NE that it appears unlikely that the constraint will bind, even with a reduced Maximum Capacity Limit as requested by the Maine Parties.

2. NSTAR Protest

55. NSTAR contends that, in understating the reliability benefits of the New York and New Brunswick ties, ISO-NE violated Market Rule 1, Commission precedent, and its own methodology, resulting in the imposition of direct costs on New England consumers totaling $35 million and indirect costs of over $275 million. In support, NSTAR states that the Commission-approved methodology requires that the Hydro Québec tie benefits be calculated based on a deterministic model, that New York and New Brunswick tie benefits be calculated based on a probabilistic model, and that the *sum* of those values would equal the total tie benefits for New England. NSTAR requests that the Commission reject the Filing Parties' proposed Installed Capacity Requirement values for the 2010-2011 Capability Year and order that the values be recalculated based on the Commission-approved methodologies.

56. According to NSTAR, when calculated consistent with Commission precedent and ISO-NE's tariff, the total tie benefits result in a value of 2,250 MW rather than the 1,860 MW that the Filing Parties propose. NSTAR reaches its conclusion by adding the probabilistic total of tie benefits attributable to New York (200 MW) and New Brunswick (650 MW) to the deterministic total of HQ Capability Credit tie benefits (1,400 MW).

By contrast (as stated previously), ISO-NE conducted a probabilistic study of the three areas, which determined that there is a total of 1,860 MW of tie benefits available to New England.

57. NSTAR states that as a result of ISO-NE's methodology, internal capacity requirements are overstated and reliability benefits from adjacent power pools are understated by 390 MW, requiring customers to support additional capacity without any commensurate reliability benefits. NSTAR contends that ISO-NE's overstated capacity requirements could have the adverse impact of shifting the demand curve and increasing the clearing price in the FCA, as well as passing on to consumers the further cost of acquiring an additional 390 MW of capacity. NSTAR speculates that raising the internal capacity demand will increase auction prices by \$0.68/kW-month,[32] resulting in an annual cost of over \$275 million, as well as a direct cost of \$35 million to acquire the additional 390 MW of capacity over twelve months.[33] Additionally, NSTAR argues that the diminished tie benefits reduce the reliability value of the interconnections, which will discourage new investment in interconnection facilities

58. In support of its position, NSTAR provides a detailed history of the development of ISO-NE's tie benefits methodology. NSTAR states that the Draft Design Basis Document (i.e., the DBD) for calculating Installed Capacity Requirement values that the NEPOOL Participants Committee approved on September 8, 2006, explained that New York and New Brunswick tie benefits were to be calculated based on a probabilistic methodology while HQ tie benefits were to be calculated using a deterministic methodology. NSTAR also states that it is clear from section III.12.9 of Market Rule 1 that the provision that tie benefits with neighboring control areas should be calculated by using a probabilistic methodology applies only to New York and New Brunswick interfaces. Moreover, NSTAR points out that section III.12.9.2 of Market Rule 1 provides that tie benefits over the HQ Interconnection shall be calculated under a deterministic methodology.

59. NSTAR maintains that, in ensuing stakeholder meetings, ISO-NE developed and proposed a methodology for conducting a tie benefits analysis consistent with the methodology proposed by NSTAR in its protest. NSTAR contends that subsequently

---

[32] NSTAR bases this estimate on NYISO's capacity structure, which is designed to mimic a competitive market. NYISO's demand curve slope is \$0.175/kW-month per 100 MW. *See* NSTAR Protest at 11.

[33] NSTAR derives this value based on the acquisition of 390 MW at \$7.50/kW-month for 12 months.

ISO-NE alternatively proposed to calculate the overall tie benefits of all three areas in a single probability analysis, because this method had support from the NEPOOL Power Supply Planning Committee (PSPC).

60. According to NSTAR, ISO-NE stated that PSPC did not support the results of the initial study, "because [HQ Capability Credit value] was modeled as a firm resource, which would be incorrect, absent a contract." NSTAR argues that PSPC's opinion goes against Commission precedent which requires the HQ Interconnection to be treated like internal generation for purposes of determining tie benefits. NSTAR states that ISO-NE's original methodology was correct and consistent with Commission precedent, and that ISO-NE has mistakenly departed from the Commission's policy requiring that the Installed Capacity Requirement reflect HQ Capability Credits based on a deterministic model.

61. Finally, NSTAR states that the Filing Parties' claim that the tie benefits approach used in the instant filing is no different from the approach used in previous years of calculating Installed Capacity Requirement is false. Specifically, NSTAR states that, in previous years, ISO-NE's "at criteria" assumption reflected the planning required reserve margins of the various neighboring systems, as opposed to the Loss of Load Expectation. NSTAR explains the change in "at criteria" is the reason for such a large difference between the results of the calculations from the 2003 study of tie reliability benefits[34] and the instant 2010 study (i.e., one case of the 2003 study showed tie benefits "at criterion" valued at 2,980 MW, while the 2010 study showed 1,860 MW).[35]

a. <u>Answers</u>

62. NEPOOL agrees that ISO-NE's methodology for calculating HQ Capability Credits follows Market Rule 1 and is consistent with Commission precedent. NEPOOL asserts that NSTAR's request represents an impermissible collateral attack on the previous Commission order in Docket No. ER07-365, which is a previous filing by ISO-NE wherein the Commission accepted ISO-NE's Installed Capacity Requirement calculation methodology.

63. Responding to NSTAR's claim that ISO-NE's interpretation of section III.12.9 of Market Rule 1, as reflected in the Joint Filing, "contradicts the express language contained in . . . the [Design-Based Document or DBD] upon which the [Installed

---

[34] As support, NSTAR cites the 2003 NEPOOL Tie Reliability Benefits Study, Docket No. ER04-670-000 (2003).

[35] *See* NSTAR Protest at 22.

Capacity Requirement] Market Rules were developed" (NSTAR Protest at 12, citing to Attachment F to the Protest), NEPOOL notes that the Participants Committee-supported DBD was used as the basis for developing the Installed Capacity Requirement Market Rules. NEPOOL further points out that the DBD stated that a procedure to calculate tie benefits associated with specific ties between New England and external control areas was under development and would be incorporated as appropriate. NEPOOL states, therefore, that NSTAR's claim that section III.12.9 of Market Rule 1 deviates from the understanding in the DBD on this issue has no support in the language of the DBD. Finally, NEPOOL also contends that NSTAR misconstrues the probabilistic calculation of total tie benefits with the subsequent allocation of tie benefits.

64. Contrary to NSTAR's arguments, ISO-NE maintains, *inter alia*, that its tie benefits calculation methodology conforms to controlling authorities. According to ISO-NE, NSTAR maintains that for the HQ Interconnection, section III.12.9.2 of Market Rule 1 provides that ISO-NE must calculate the MW value of the tie benefits over the HQ Interconnection using a deterministic methodology. ISO-NE posits, however, that NSTAR selectively ignores that sections III.12.9.1 and III.12.9.2 of Market Rule 1 address ISO-NE's required methodology for allocating tie benefits—not the methodology for calculating overall tie benefits. Unlike the methodology for calculating overall tie benefits, the methodology for allocating tie benefits does use the deterministic methodology, but solely with respect to HQ Capability Credits; i.e. the probabilistic methodology determines the total tie benefits value, and from that total value, the HQ Capability Credits for the HQ Interconnection are allocated deterministically.

65. In its answer, ISO-NE also states that its methodology is in accordance with applicable Commission precedent. ISO-NE avers that no Commission order referenced by NSTAR supports or requires the tie benefits calculation approach that NSTAR seeks to impose. ISO-NE further states that NSTAR's hybrid approach would overstate the total tie benefits available to New England by assuming that the potential capacity available for sales from Québec would be dedicated to serving New England needs, while in reality control areas interconnected with Québec (*e.g.*, New York) would have equal right to expect emergency assistance from the same surplus. ISO-NE states that the use of this hybrid approach would increase the chances of producing erroneous total tie benefit projections. ISO-NE states that its approach to calculating total tie benefits does not suffer from these flaws because the probabilistic model better captures the range of possible outcomes.

66. In response to NSTAR's assertion that the proposed tie benefit levels used in the past are well below the maximum of 3,975 MW that the NPCC indicated was reasonable, ISO-NE explains that the value indicated to be reasonable by NPCC refers to the 2,000 MW of tie benefits used in the 2003 study, not the 3,975 MW. ISO-NE states that it has

calculated the tie benefits based on the best load and resource assumptions available for the 2010-2011 Capability Year; therefore, NSTAR's complaint regarding the "at criteria" methodology is inappropriate.

b. Commission Determination

67. We disagree with NSTAR's claim that calculating the total tie benefits in a manner consistent with Commission precedent and ISO-NE market rules results in a value of 2,250 MW, rather than the 1,860 MW that the Filing Parties propose. Moreover, NSTAR's proposal for calculating New England tie benefits would violate the ISO-NE Tariff and Commission precedent as explained below.

68. The Filing Parties have calculated tie benefits over the Hydro Québec interconnection in a manner consistent with the ISO-NE Tariff. The FCM Settlement Agreement requires that tie benefits attributable to the Hydro Québec interconnection be calculated on a deterministic basis.[36] The Commission accepted as just and reasonable the FCM Settlement Agreement, including use of deterministic modeling of tie benefits derived from the Hydro Québec interconnection.[37] Further, as discussed above, section III.12.9.2 of Market Rule 1 provides that tie benefits over the Hydro Québec interconnection be calculated using a deterministic methodology. Consistent with the ISO-NE Tariff, the Filing Parties have proposed 1,400 MW of tie benefits from the Hydro Québec interconnection, as calculated using a deterministic methodology.

69. The Filing Parties have also proposed a total amount of tie benefits for the entire New England control area consistent with the ISO-NE Tariff. As discussed above, section III.12.9 of Market Rule 1 requires that ISO-NE calculate tie benefits for the New England control area "using a probabilistic multi-area reliability model." The Filing Parties' proposal conforms to this requirement of the ISO-NE Tariff by calculating the total New England control area tie benefits from neighboring control areas on a probabilistic basis. Consistent with section III.12.9 of the ISO-NE Tariff, the Filing Parties have appropriately proposed a total amount of tie benefits available to the New England control area of 1,860 MW, as determined by a probabilistic methodology. Moreover, we disagree with NSTAR that this tariff section applies only to the New York and New Brunswick tie benefits. We find no language in this tariff section to support that position.

---

[36] FCM Settlement Agreement § III.B.3(a).

[37] *Devon Power LLC*, 115 FERC ¶ 61,340, *order on reh'g*, 117 FERC ¶ 61,333 (2006).

70. In numerous past orders accepting the New England Installed Capacity Requirement determination (including the calculation of tie benefits), 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.[38] Accordingly, we find that the Filing Parties' proposed calculation and allocation of tie benefits is consistent with Market Rule 1 and Commission precedent.

71. NSTAR's alternative proposal of assuming 2,250 MW of total tie benefits available to the New England control area ignores directives of the Commission and the requirements of the ISO-NE Tariff. As explained, ISO-NE is required to use a probabilistic analysis for calculation of total tie benefits for the New England control area, which results in 1,860 MW total tie benefits, not 2,250 MW. NSTAR's proposal would require the Filing Parties to violate section III.12.9 of Market Rule 1 and calculate total tie benefits for the New England control area in excess of the amount determined probabilistically, notwithstanding the stated purpose of the probabilistic analysis to comprehensively evaluate all possible uncertainties.

72. Furthermore, NSTAR's proposal is imprudent because it attempts to maximize the amount of tie benefits available to the New England control area, and in the process, overstates the tie benefits. It is unreasonable to assume 2,250 MW of the total tie benefits are available to New England over its interconnections with neighboring control areas, because NSTAR's proposal double counts a portion of the tie benefits by failing to deduct the 1,400 MW of tie benefits attributed to HQ Capability Credits. NSTAR's proposal counts some tie benefits twice: once to the holders of HQ Capability Credits and a second time to other load-serving entities (i.e., LSE) in New England.

---

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

73. We next turn to NSTAR's assertion that ISO-NE has changed its "at criteria" assumption to reflect a Loss of Load Expectation, not the planning required reserve margins of the various neighboring systems, and as a result, the amount of tie benefits as calculated in the 2010 Study (1,860 MW) is substantially lower than the amount calculated in the 2003 Study (2,980 MW). 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.

74. 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.

75. On a long-term basis, and as detailed elsewhere in this order, we would support a stakeholder process that would revisit the tie benefit methodology, including whether the deterministic approach for calculating HQ Capability Credits remains the most efficient approach under a locational capacity construct like FCM.

3. LIPA Comments

76. LIPA asserts that there is no justification for using different methodologies to compute the tie benefits of the Cross Sound Cable and Hydro Québec interconnections. LIPA states that the Cross Sound Cable and Hydro Québec interconnections are the only two major DC transmission facilities linking the New England Control Area with adjoining control areas. LIPA claims that DC facilities provide a more linear measure of tie benefits because the direction of the flows over the tie can be controlled, so it is appropriate to treat the Cross Sound Cable and Hydro Québec interconnections similarly in calculating tie benefits.

Commission Determination

77. We disagree with LIPA's assertion that the Cross Sound Cable and Hydro Québec interconnections should be treated similarly in calculating tie benefits simply because

they are DC facilities. As we have noted previously, there is a key distinction between the Cross Sound Cable interconnection and the Hydro Québec interconnection.[39] Capacity imported from the New York to New England control areas may travel across transmission interfaces other than the Cross Sound Cable. Those other transmission interfaces are AC facilities, so it is impossible to forecast with certainty the amount of capacity that will flow through the facilities. This characteristic of the Cross Sound Cable interconnection differs from the Hydro Québec interconnection. All capacity sent through the Hydro Québec interconnection flows only through the Hydro Québec interconnection, not through any other facilities. Thus, we have found that it is appropriate to calculate tie benefits over the Hydro Québec interconnection on a deterministic basis.[40]

C. Ongoing Proceedings against Commission Determination of Installed Capacity Requirement

78. As Attachment 4 to its filing, the Filing Parties included representations from the Connecticut Department of Public Utility Control, the New Hampshire Public Utilities Commission, the Rhode Island Public Utilities Commission, the Vermont Department of Public Service, and the Vermont Public Service Board (collectively, the Representation PUCs) regarding the Commission's jurisdiction, *vel non*, to establish the level of New England's Installed Capacity Requirement. They maintain their positions in other ongoing proceedings in which the Connecticut Department of Public Utility Control challenged ISO-NE's Installed Capacity Requirement filings. Notwithstanding their positions, the Representation PUCs support ISO-NE's recommended Installed Capacity Requirement value of 33,705 MW in the instant filing for the 2010-2011 Capability Year. Moreover, the Representation PUCs affirm that their statement is intended to "assure market participants that if the courts finally determine that the states—not the Commission—have jurisdiction to establish the [Installed Capacity Requirement] level," the Representation PUCs will not seek to overturn any Installed Capacity Requirement level accepted by the Commission and which has been used in New England's electricity markets prior to December 2, 2008, or the date of the court's final determination, whichever is earlier.

79. In an intervention and comments, the Massachusetts Attorney General maintains the position that the Commission lacks jurisdiction to establish Installed Capacity Requirement values for New England, but concurs with the positions of ISO-NE, NEPOOL, and the Representation PUCs.

---

[39] *ISO New England Inc.*, 118 FERC ¶ 61,157, at P 35-37 (2007).

[40] *Id.* P 36.

80. In a separate filing, the Maine Parties maintain that the Commission has no jurisdiction to determine Installed Capacity Requirement values because to assert such jurisdiction would exceed the authority that Congress granted in the FPA. The Maine Parties agree that it would be an inefficient use of resources to litigate the Installed Capacity Requirement jurisdiction issue for a third time in this proceeding. The Maine Parties state, however, that they do not waive this issue as it applies to this proceeding and incorporate by reference their arguments previously made.

Commission Determination

81. We note that the Representation PUCs, the Massachusetts Attorney General, and the Maine Parties, reaffirm their positions with respect to the Commission's jurisdiction to establish Installed Capacity Requirement for New England by reference to their arguments in other pending proceedings. As explained previously and at length in other Commission orders, the Commission maintains that it has jurisdiction over the Installed Capacity Requirement because it is a component of jurisdictional wholesale rates.[41]

D. Prospective Stakeholder Process

82. HQUS and BEMI do not take a position on the Installed Capacity Requirement or Capacity Credit values presented by the Filing Parties. Instead, they support the Filing Parties' discussion of the need for Commission endorsement of any stakeholder process to reform the methodologies for calculating HQ Capability Credits and for allocating tie benefits for power years beyond 2010-2011. They acknowledge the inconsistencies in 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, respectively.

83. HQUS and BEMI contend that a Commission mandate is necessary for any change to occur. HQUS and BEMI maintain that the Commission's guidance should be that stakeholders (1) must develop a consistent methodology to value the capacity benefit of all interties, but that they (2) should not address changes in the current tariff treatment of the HQ Interconnection. They also state that the Commission should require stakeholders to resolve these issues by a date certain that would allow incorporation of improvements in the calculation methodology in time for the second FCM auction in December 2008.

84. As an Interconnection Rights Holder, Central Vermont states that it supports the use of the stakeholder process to examine and resolve disagreements and consider alternative solutions for determining the Installed Capacity Requirement for future

[41] *See, e.g.*, *ISO New England Inc.*, 121 FERC ¶ 61,125, at P 33-39 (2007).

Capability Years, beginning with 2011-2012, as long as the rights of the Interconnection Rights Holders are recognized and the parties are open to compromise. Further, Central Vermont expresses no opinion here on the method used to develop the current Installed Capacity Requirement or Capacity Credit values.

85. LIPA similarly supports the proposal to use the stakeholder process to consider alternative proposals to equitably allocate tie benefits and to change the market rules. LIPA requests that the Commission signal its willingness to entertain a change in how tie benefits are presently established and to provide guidance on prospective market rules. LIPA specifically urges the Commission to support having ISO-NE investigate the way tie benefits are determined for all tie lines, including the ties that connect New England to New York from the different sub-areas.[42]

86. The Maine Parties agree that the Commission should direct ISO-NE and NEPOOL to undertake a stakeholder process to address the issue of tie benefits as they relate to the FCA.

87. In their answers, the IRH Management Committee and NSTAR contend that HQUS and BEMI are engaging in an impermissible collateral attack on previous Commission orders approving HQ Capability Credit calculations. The IRH Management Committee states that the Commission should not permit HQUS to use the stakeholder review process to change the Commission-approved methodology for calculating HQ Capability Credits. The IRH Management Committee states that any alternative method of allocating tie benefits developed as a result of a stakeholder review process must be consistent with the Commission's prior HQ Capability Credits orders—and such a process should not be permitted to change the Commission-approved methodology of calculating HQ Capability Credits. The IRH Management Committee avers that the Commission has ruled repeatedly that HQ Capability Credit values should be calculated based on the availability of generation resources in Québec and not based on the monthly need for those resources in New England. NSTAR concludes that HQUS and BEMI are attempting to reduce the value of the Interconnection Rights Holders' investment in the HQ Interconnection and reduce HQ Capability Credit entitlements by suggesting that tie benefits on the HQ Interconnection and, accordingly, HQ Capability Credits, be valued

[42] LIPA is a joint owner of the undersea 1385 cable—a 138 kV AC cable with a capacity of 286 MW in either direction—that directly connects Southwest Connecticut with Long Island, New York. LIPA has also executed a Firm Transmission Capacity Purchase Agreement with Cross Sound Cable Company, LLC through which LIPA holds capacity rights over the Cross Sound Cable from Long Island to New Haven, Connecticut.

based on a probabilistic methodology rather than a deterministic methodology. NSTAR and the IRH Management Committee state that they should not be forced to defend again, nor should the Commission have to reexamine, this well-established methodology for calculating HQ Capability Credits.

Commission Determination

88. The issue of HQ Capability Credits and the tie benefits that accrue to the New England control area because of the Hydro Québec interconnection has a significant history before the Commission. In the First HQ Capability Credits Order, the Commission found that "the [Hydro Québec] Interconnection has become critical to maintaining system reliability" and that "an outage of the [Hydro Québec] Interconnection is the single largest loss contingency planned for and secured against by ISO-NE."[43] The Commission stated that "the reliability benefits that the [Hydro Québec] Interconnection provides exist because of the Interconnection Rights Holders' contractual obligation to pay for all of the costs of the [Hydro Québec] facilities."[44] The Commission reasoned that Interconnection Rights Holders had exclusive access to Capability Credits due to contractual obligations in the Restated NEPOOL Agreement[45] and because the Interconnection Rights Holders paid for the Hydro Québec facilities through separate agreements, not through the New England Power Pool tariff.[46] The Commission found that tie benefits "should be calculated to reflect the actual reliability benefits associated with the [Hydro Québec] Interconnection and generation resources in Quebec."[47] Under the ICAP capacity construct, the Commission concluded that the HQ Interconnection must be treated in a manner consistent with NEPOOL's internal generation with respect to the level of Installed Capacity provided. Those parties that paid for the Hydro Québec facilities—the Interconnection Rights Holders—are assigned capacity credits based on that tie benefit calculation. This calculation and allocation methodology has remained in place since 2002, and has been affirmed in the FCM Settlement Agreement, ISO-NE's Market Rule 1, and in various Commission orders.

---

[43] First HQ Capability Credits Order, 99 FERC ¶ 61,187, at P 29.

[44] *Id.*

[45] *Id.* P 28.

[46] *Id.*

[47] First HQ Capability Credits Order on Rehearing, 100 FERC ¶ 61,227, at P 24.

89. The advent of the FCM regime has ripened the issue of tie benefit calculation methodology for New England stakeholder discussion. Especially pertinent for analysis is the appropriateness of the current methodology for calculating tie benefits from the Hydro Québec interconnection in light of the more stringent availability and deliverability requirements and locational aspect of the FCM, applicable to all accepted resources. Specifically, we agree with ISO-NE that it is not clear that the current deterministic tie benefit allocation for Hydro Québec takes into account uncertainties with future load and capacity or the sharing of the Québec resources with other control areas, especially in support of an auction that takes place three years in advance of the Capability Year. Further, as explained above,[48] while we agree with ISO-NE that it is not a concern for the first FCA, tie benefits may have a direct impact on whether or not a transmission constraint is expected to bind and thus may have an impact on capacity prices.

90. Several parties advocate commencing a stakeholder process to reconsider the current methodologies for determining and allocating tie benefits. Now that a locational capacity market is in place for New England, we would support a stakeholder process that revisits the tie benefit methodology. In support of a July 2008 filing to the Commission addressing the tie benefit calculation, we encourage 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 does not reflect an overly aggressive estimate of tie benefits based on unrealistic assumptions, i.e., that total New England tie benefits do not exceed the amount determined probabilistically. We will require the 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.

E. <u>Waiver of Notice Requirement</u>

91. The Filings Parties' requested effective date of December 10, 2007, falls on the sixtieth day after the filing date. Section 205 of the Federal Power Act, however, requires sixty days notice, which means that the effective date would be on the sixty-first day after filing, which here would be December 11, 2007.[49] Accordingly, ISO-NE's proposed values for the Installed Capacity Requirement, HQ Capability Credits, and related parameters will be effective December 11, 2007.

---

[48] *See supra* P 50-51, 53.

[49] 16 U.S.C. § 824d (2000).

The Commission orders:

(A) ISO-NE's proposed Installed Capacity Requirement and related values for the 2010-2011 Capability Year are hereby accepted for filing, to be effective December 11, 2007, as discussed in the body of this order.

(B) ISO-NE must make a filing with this Commission addressing the tie benefits methodology no later than July 2008, as discussed in the body of this order

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.