118 FERC ¶ 61,157
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
New England Power Pool

Docket No. ER07-365-000

ORDER ACCEPTING TARIFF CHANGES
AND REQUIRING COMPLIANCE FILING

(Issued February 28, 2007)

1. In this order, the Commission accepts proposed tariff changes jointly filed by ISO New England, Inc. (ISO-NE) and the New England Power Pool Participants Committee (NEPOOL) to revise ISO-NE's Market Rule 1 to formalize the processes and methodologies used to determine the Installed Capacity Requirements (ICR) for the New England Control Area, and requires a compliance filing with regard to those changes.

Background

2. In 2006, the Commission approved a settlement agreement pursuant to which New England market participants will develop a forward capacity market (FCM Settlement).[1] In order to accommodate the FCM Settlement, ISO-NE and NEPOOL have revised portions of the process for developing the ICR.

3. The ICR is the amount of resources needed to meet the reliability requirements defined for the New England control area: it is a projection of the minimum amount of capacity required to serve load (*i.e.*, peak demand for electricity) reliably in the New England region. The ICR is the total number of MW that Load Serving Entities (LSEs) will be required to purchase through the Forward Capacity Auctions, and thus a primary

[1] *Devon Power, LLC* (*Devon Power*), 115 FERC ¶ 61,340, *order on reh'g and clarification*, 117 FERC ¶ 61,133 (2006) (jointly, FCM Orders).

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determinant of capacity prices. The ICR is determined in accordance with existing resource planning reliability criteria, the goal of which is to ensure that resources are planned and installed such that the probability of disconnecting non-interruptible customers due to deficiency will be, on the average, no more than once in ten years.[2]

4. The method for determining ICR is not currently described in the market rules. Historically, ISO-NE, with input from participants, established ICR values prior to the beginning of the ISO-NE power year (on a MW basis for each month of the power year).[3] These values were filed annually with the Commission pursuant to the ISO-NE tariff.[4] Each market participant had a capacity responsibility in each month to procure a proportional share (based on the participant's share of peak load) of the applicable ICR value. A participant was able to satisfy its capacity obligation through several means, including bilateral contracting, ISO-administered auctions, owning generation facilities, and demand-side resources.

5. Pursuant to section 205 of the Federal Power Act (FPA), on December 22, 2006, ISO-NE and NEPOOL jointly submitted proposed revisions to the ISO-NE tariff that are designed to memorialize the processes and methodologies used to determine the ICR. ISO-NE and NEPOOL state that the proposed revisions neither significantly change the existing methodology to calculate ICR nor alter the reliability criteria with which the ICR

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[2]ISO-NE's and NEPOOL's proposal also contains new parameters and measurements for related elements of New England's market design, including Local Sourcing Requirements (the minimum amount of capacity that must be located within an import-constrained load zone), and the Maximum Capacity Limits (the maximum amount of capacity that can be procured in an export-constrained load zone to meet the ICR) for use in the FCM. Transmission constraints limit the amount of capacity that can be transferred into import-constrained sub-regions. Thus those sub-regions must procure a minimum number of MWs from within the sub-region to meet system-reliability requirements. As part of the ICR process, ISO-NE will determine the Local Sourcing Requirement and the Maximum Capacity Limit prior to each forward capacity auction.

[3] ISO-NE's Power Year runs from June 1 through May 31 of the following year.

[4] ISO-NE Tariff, former Market Rule 1 at section III.8.1 (*see ISO New England, Inc.*, 115 FERC ¶ 61,149 at P 2 n. 2 (2006) ("Under section III.8.1 of Market Rule 1 . . . the ISO calculates the IC Requirements each Power Year and, after consultation with stakeholders (as required by the Participants Agreement), ISO-NE must file the [Installed Capacity] Requirements with the Commission pursuant to section 205 of the FPA").

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must comply.[5] The proposed revisions do, however, alter existing processes for establishment of the ICR, as necessary to accommodate the FCM. Under FCM, ISO-NE will hold auctions for capacity three years in advance, and so ICR will similarly need to be calculated in advance by using "assumptions . . . regarding the resources that will be available resources and the forecasted load for the relevant time period."[6] ISO-NE has utilized the Westinghouse/ABB Capacity Model Program in establishing New England's annual ICR values, and has formulated assumptions regarding generating and demand response resources, system load forecasts, and the reliability benefits from direct connection to the neighboring power systems of Quebec, New York and the Canadian Maritimes (tie benefits) which it has incorporated into those models.[7] The modeling to be conducted pursuant to sections III.12.6, III.12.7, III.12.8, and III.12.9 of the proposed tariff revisions is a comprehensive process, such that the respective results of the modeling in those sections cannot be used independently.[8]

6. ISO-NE and NEPOOL state that the proposed revisions to Market Rule 1 are not comprehensive: some details of calculating ICR and Local Sourcing Requirements will be reflected in the ISO's annual filing of ICR values as part of the FCM process. For example, the proposed provisions anticipate that generator availability metrics will evolve over time and that detailed generator availability assumptions will be reflected in the annual filings. These annual filings will provide a forum in which the Commission will review whether the ICR and Local Sourcing Requirement values are just and reasonable, and interested stakeholders will continue to have the opportunity to raise their concerns at that time. ISO-NE and NEPOOL state that the ICR rules proposed in the instant filing will define the process for calculating ICR, whereas the annual filings will identify the assumptions used to calculate the ICR for a given period and identify the resulting numerical values.

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[5] The reliability criteria used for calculating ICR comport with the requirements of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC).

[6] Transmittal at 2.

[7] The Westinghouse Model is a computer program that calculates system Loss of Load Expectation (LOLE) using probabilistic mathematics based on a range of potential load and capacity conditions.

[8] For purposes of the modeling in those sections, demand resources will be treated in a manner comparable to supply resources.

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7. ISO-NE and NEPOOL conducted an extensive stakeholder process. The proposed market-rule revisions were considered by stakeholders and received an 80.55 percent vote in support from the NEPOOL Participants Committee.

8. ISO-NE and NEPOOL request that the Commission allow the proposed revisions to become effective on March 1, 2007. ISO-NE and NEPOOL state that participants need to have some certainty as to the ICR, Local Sourcing Requirements and Maximum Capacity Limits that will be in effect for the initial forward capacity auction.[9]

Protests and Comments

9. The filing was noticed in the Federal Register,[10] with interventions, comments or protests due by January 16, 2007. NEPOOL, Constellation Energy Commodities Group *et al.* (Constellation), the New York State Reliability Council (NYSRC), H.Q. Energy Services (U.S.), Inc. (HQUS), Consolidated Edison Energy, Inc. (Con Ed), the Long Island Power Authority (LIPA), Exelon Corporation (Exelon) and the Connecticut Department of Public Utility Control (CT DPUC) filed timely motions to intervene and protests or comments. National Grid USA (National Grid), Milford Power Company, the Massachusetts Department of Telecommunications and Energy, the New York Independent System Operator, Dominion Energy Marketing *et al.*, New England Conference of Public Utilities Commissioners, Northeast Utilities Service Company, NRG Companies and NSTAR Electric and Gas Company filed timely motions to intervene.

10. ISO-NE, NEPOOL and National Grid, *et al.*, filed motions for leave to answer and answers to the protests and comments above. United Illuminating Company also sought leave to intervene out of time. LIPA opposed ISO-NE's motion to file an answer; alternatively, if the Commission allows ISO-NE's answer, LIPA moves for the establishment of a technical conference to clarify what it characterizes as ISO-NE's violation of the FCM Settlement, and the basic functioning of the FCM operations with respect to imports and exports of capacity. The NYSRC also filed motion for leave to file an answer, and an answer to ISO-NE's answer.

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[9] Under the Settlement Agreement, the first forward capacity auction is intended to occur in early 2008 for a Capacity Commitment Period beginning June 1, 2010.

[10] 72 Fed. Reg. 775 (2007).

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Discussion

Procedural Matters

11. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214 (2006)), all timely filed motions to intervene and any motions to intervene out-of-time filed before the issuance date of this order are granted. Granting late intervention at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2006), prohibits an answer to an answer unless otherwise ordered by the decisional authority. We will accept ISO-NE's, NEPOOL's, National Grid's answers because they have provided information that assisted us in our decision-making process. We deny LIPA's motion for a technical conference, on grounds discussed *infra*. We are not persuaded to accept the NYSRC's answer to ISO-NE's answer, and therefore reject it.

Analysis

Jurisdiction and Standard of Review

Protests

12. In its protest, the CT DPUC asserts that the Commission does not have jurisdiction to establish a methodology for the determination of ICR, since that would exceed the authority granted to the Commission by Congress in the FPA. The CT DPUC argues that the FPA expressly directs that the Commission "shall not have jurisdiction . . . over facilities used for the generation of electric energy." The CT DPUC argues that, while the Commission has the authority to establish the price of capacity or how capacity requirements will be allocated among LSEs, it does not have jurisdiction to dictate the amount of ICR that must be purchased. The CT DPUC asserts that the New England states have demonstrated cooperation in developing regional capacity requirements and that acceding to the New England states' authority to set resource requirements will not jeopardize regional reliability.

13. ISO-NE and NEPOOL note that litigation regarding the Commission's authority to establish the ICR is currently pending before the U.S. Court of Appeals for the District of Columbia Circuit.[11] These proposed rules governing the establishment of the ICR values

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[11] *See Connecticut Department of Public Utility Control* v. *Federal Energy Regulatory Commission (CT DPUC)*, Docket No. 05-1411.

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were developed presuming that the Commission's determination of its authority over the ICR would be sustained by the Court. ISO-NE and NEPOOL state that, to the extent that the Court concludes otherwise, revisions to the ICR-related Market Rule provisions will be developed and filed with the Commission in the future. In their answers, ISO-NE and NEPOOL additionally note that the CT DPUC participated extensively in the stakeholder process that led to NEPOOL's determination of ICR, and it is thus inappropriate to consider CT DPUC to have been deprived of the opportunity to participate in the development of ISO-NE's ICR methodology.

14. Con Ed argues that the correct standard of review for the Commission's consideration is not whether the proposed filing is “just and reasonable.” Con Ed argues that this standard or review applies to utility rates, not system adequacy or reliability standards. Con Ed contends that the ICR methodology is subject to the Administrative Procedure Act’s “substantial evidence” standard. According to Con Ed, the "just and reasonable" standard as applied in the cases cited by ISO-NE arose in the context of utility rates, and that, since ICR is a reliability standard rather than a utility rate, it is not subject to the "just and reasonable" standard.

Commission Decision

15. The Commission finds that it has jurisdiction to consider the proposed mechanism for the determination of ICR. As noted above, the question of the Commission's jurisdiction over ICR is already on appeal in the D.C. Circuit. As the Commission stated in its order accepting the FCM Settlement, however, the FCM settlement "establish[es] a mechanism and market structure for the purchase and sale of installed capacity at wholesale in interstate commerce and to determine the prices for those sales, bringing it squarely within the Commission’s jurisdiction under the FPA."[12] Thus, in this context, the ICR is one of the principal determinants of the price of capacity and, hence, falls within the Commission's jurisdiction to review "any rate, charge or classification" charged by a public utility for electric transmission or sales subject to agency jurisdiction, and "any rule, regulation, practice, or contract affecting such rate, charge or classification."[13] ISO-NE's mechanism to determine ICR is a "practice . . . affecting" the price of capacity, and as such falls within the Commission's jurisdiction.

16. This determination is consistent with prior court decisions regarding the Commission's jurisdiction over capacity requirements and charges. *See Municipalities of*

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[12] *Devon Power* at P 201.

[13] FPA section 206(a), 16 U.S.C. § 824e(a).

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Groton v. *FERC* (*Municipalities of Groton*),[14] in which the U.S. Court of Appeals for the D.C. Circuit upheld the Commission's jurisdiction to review the capability responsibility charges made by NEPOOL to each NEPOOL member for that member's share of capacity responsibility for the pool's peak load, and stated that the charges came within "the Commission's inclusive jurisdictional mandate – which reaches . . . practices . . . 'affecting' [jurisdictional] transmissions or services."[15] The D.C. Circuit similarly held that the Commission had jurisdiction over the allocation of capacity and costs of a nuclear plant among multiple operating companies of an integrated utility system, because "while [provisions allocating capacity] do not fix wholesale rates, their terms do directly and significantly *affect* the wholesale rates at which the operating companies exchange energy."[16]

17. This view is also consistent with the Commission's recent order conditionally accepting the market redesign for the California Independent System Operator (CAISO),[17] in which the Commission addressed similar jurisdictional concerns. In response to the assertion that resource adequacy requirements were outside of the Commission's purview, the Commission stated:

> [W]here an interconnected transmission system is operated on a regional basis as part of an organized market for electricity . . . all users of the system are interdependent, particularly with respect to reliability, *i.e.*, one participant's reliability decisions can impact the reliability of service available to other participants and the related costs the other participants must bear. . . . We find that, in situations where one party's resource adequacy decisions can cause adverse reliability and costs impacts on other participants in a regionally operated system, it is appropriate for us to

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[14] 587 F.2d 1296 (D.C. Cir. 1978).

[15] *Id.* at 1302.

[16] *Mississippi Industries* v. *FERC*, 808 F.2d 1525, 1542 (emphasis in original), *vacated in part on other grounds*, 822 F.2d 1103 (D.C. Cir. 1978).

[17] *Cal. Indep. Sys. Operator Corp.* (*CAISO*), 116 FERC ¶ 61,274 (2006), *reh'g pending*.

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> consider resource adequacy in determining whether rates remain just and reasonable and not unduly discriminatory.[18]

18. The Commission further stated that "resource adequacy plays an important role in addressing whether Commission-jurisdictional wholesale prices reflect the exercise of market power or the scarcity of supply."[19] Noting that it was also approving bid caps for energy markets in California, the Commission stated:

> These bid caps are premised on the notion that bids above these levels may not reflect true scarcity pricing, but rather the exercise of market power or abuse that results in rates that are not just and reasonable. This premise is only valid, however, if there is some mechanism – other than energy price increases – to encourage the construction of new generation where and when needed. Consequently, in the absence of a workable resource adequacy program, it would be difficult for us to approve such bid caps. Without a workable program, the bid caps would simply inhibit new supply, and thereby harm customers, rather than protecting customers from the exercise of market power or abuse.[20]

19. Similar considerations apply in New England. The ICR requirement in issue here is an integral component of the charges that ISO-NE makes to its member LSEs.[21]

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[18] *CAISO* at P 1113, *citing Cal. Indep. Sys. Operator Corp*., 115 FERC ¶ 61,172, at P 36 (2006) and *Gainesville Utils. Dep't* v. *Fla. Power Corp*., 402 U.S. 515, 529 (1971) (Commission has the "responsibility to the public to assure reliable efficient electric service").

[19] *CAISO* at P 1114.

[20] *Id.*

[21] As the CT DPUC acknowledges,

> ICR plays a pivotal role under the FCM Settlement in determining how much capacity New England's electric customers must procure. A key feature of the FCM Settlement is that the amount of capacity purchased in the [Forward Capacity Auction] will equal one hundred percent of ICR. Thus, to the extent that ICR is greater than the amount needed to ensure reliability, customers will buy more capacity than is just and reasonable.

CT DPUC protest at 4, *citing* FCM Settlement, section 11.III.C.

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Because ISO-NE will determine a single ICR requirement for its entire system (later to be subdivided among its LSEs), the Commission is required to review ISO-NE's ICR methodology to ensure that these charges, which are levied on all LSEs, are determined in a just and reasonable manner. Additionally, ISO-NE, like CAISO, has bid caps in its energy markets, and similarly in New England, absent an affirmative mechanism to elicit the construction of new supply, those bid caps would simply harm customers by discouraging such construction, rather than protecting customers from the exercise of market power or abuse.

20. The CT DPUC asserts that the FPA expressly states that the Commission does not have jurisdiction over facilities used for the generation of electric energy, and thus the Commission has no jurisdiction to establish a methodology for determining ICR. This argument is inapposite. The Commission is not asserting jurisdiction over generating facilities. It is asserting jurisdiction over an essential component of the charge for wholesale capacity in interstate commerce. In doing so, the Commission is not requiring that any individual state build generation or that any participant satisfy its capacity obligation via a particular resource or set of resources. Furthermore, the Commission notes that under the previous capacity market design in New England, a participant was not limited to generation resources in satisfying its capacity obligation. Participants were able to satisfy their capacity obligations via a variety of resources, including bilateral purchases of capacity, demand-side resources and combinations thereof. The Commission notes that the FCM Settlement Agreement provides for procurement of that same variety of resources, and thus does not require states to construct new generation resources. Finally, ISO-NE and NEPOOL state that the proposed provisions are not intended to supplant ISO-NE’s annual filing of ICR values for Commission review. The Commission finds that it is just and reasonable for the Commission to consider ISO-NE’s projection of the minimum amount of capacity necessary to reliably serve load.

21. Moreover, as we stated in *CAISO*, the Commission's responsibility to assure that wholesale rates are just and reasonable does not mean that we cannot, when appropriate, accept state determinations regarding resource adequacy requirements. In *CAISO* we stated that we could, "in appropriate circumstances, defer to state and Local Regulatory Authorities to set" resource adequacy requirements.[22] In this case, however, there is no proposal for us to consider that has been put forward by all of the New England states. The CT DPUC argues that we should not determine the ICR, but there has been no agreement among the New England states to establish an ICR and, accordingly, the CT DPUC's argument would simply create a gap. While we could, in appropriate circumstances, accept an agreement among the states or other regulatory authorities

[22] *CAISO* at P 1117.

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within a multi-state transmission organization to establish a reserve margin or other resource adequacy component of wholesale charges if we determined the arrangement was just, reasonable and not unduly discriminatory, that is not the situation presented to us here. There is no agreement among the New England states to establish the ICR and therefore nothing to which we could defer. We therefore act today to establish an integral component of the jurisdictional charge for wholesale capacity within New England to ensure that wholesale rates are just, reasonable and not unduly discriminatory.

22. For similar reasons, the Commission further finds that the appropriate standard of review is whether the ICR mechanism is just and reasonable. Con Ed's suggestion that the Administrative Procedure's "substantial evidence" standard be used instead is based on a court decision involving not section 205, but section 18 of the FPA.[23] ICR, by contrast, is a primary component of the payment for capacity that ISO-NE charges – therefore, a component of a "rate, charge or classification" charged by a public utility under section 205. Thus, the appropriate standard of review is the "just and reasonable" standard of section 205.

Allocation of Interface Capacity between Tie Benefits and Firm Capacity Imports

23. Tie benefits represent the amount of emergency assistance that may be available from the interconnections with directly connected control areas.[24] According to ISO-NE, tie benefits are a result of resource and load diversity between two control areas; for example, when New York has excess resources at a time when New England's resources are tight, New York resources could support New England's load to the extent that transmission constraints allow. Under ISO-NE's proposal, tie benefits reduce the amount of ICR needed to ensure reliability. Thus, for example, if ISO-NE determines that it needs 30,000 MW of installed capacity in order to meet its reliability objective and it determines that tie benefits total 1,000 MW, the ICR would be 29,000 MW. In this case,

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[23] *Bangor Hydro-Electric Co*. v. *FERC*, 78 F.3d 659, 663 fn. 3 (D.C. Cir. 1996). In that case, which involved the Commission's granting of a license to a hydroelectric plant rather than the Commission's review of rates, the Court was considering a case involving section 18 of the FPA, 16 U.S.C. § 811, under which "[t]he Commission shall require the construction, maintenance, and operation by a licensee at its own expense of . . . such fishways as may be prescribed by the Secretary of the Interior or the Secretary of Commerce, as appropriate."

[24] New England is directly connected to New York, New Brunswick and Hydro Quebec.

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LSEs in the aggregate would need to acquire 29,000 MW of capacity through the FCM auction. The remaining 1,000 MW of capacity needed for reliability (the tie benefit) would be assumed to be available in an emergency from the neighboring control area without capacity payments made during the FCM auction.[25]

24. Section III.D.4(a) of the FCM Settlement Agreement provides that the total amount of tie benefits assumed over a particular interface, plus the import capacity resources over that interface, cannot exceed the physical transfer capability of that interface. ISO-NE states that the settlement agreement left open for debate how to allocate the interface capability between capacity import contracts and tie benefits, and there were competing stakeholder views on this issue. Thus, ISO-NE states that in order to maintain the tie benefits the total amount of capacity imports will be limited to the transfer capability with a particular control area, minus the tie benefits assumed over that interface. ISO-NE's rationale is that the transfer capability is paid for by ultimate consumers through Network Load charges, and thus, ultimate consumers should have the right to benefit from the reduced ICR that will result from the maintenance of free-flowing ties (*i.e.*, tie benefits) between two directly connected control areas. Thus, the proposed rules require that the total amount of imports from a particular control area, plus the tie benefits with that control area, cannot exceed the transfer capability with that control area.[26] At their December 8, 2006 meeting, the NEPOOL Participants Committee voted on an alternative approach that would have afforded imports a preference over tie

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[25] Though New England would not make capacity payments to the neighboring control area, New England would need to make energy payments to the neighboring control area to the extent that the neighboring control area provided energy to New England during an emergency.

[26] *See* Transmittal at 13 n. 28:

> In order for tie benefits to occur, a portion of the interface must be free from long-term capacity commitments. Firm capacity contracts require a portion of a tie to be reserved. Because the ISO cannot double count transfer capability, the transfer capacity for tie benefits is reduced and tie benefits themselves may be reduced also. Thus, firm capacity imports over ties effectively lowers the transfer limits available to support tie benefits.

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benefits clearing in the capacity auction at external interfaces other than the HQ Interconnection. That approach failed to garner the requisite level of support.[27]

Protests

25. Constellation and HQUS argue that capacity imports, supported by contractual obligations to deliver energy when called upon, should be able to have access to the transfer capability and thereby reduce the amount of transfer capability remaining available for tie benefits.

26. Constellation argues that the approach proposed by ISO-NE and NEPOOL, which limits the import transactions across ties with areas directly connected to ISO-NE's control area, compromises reliability, and that allowing parties with contractual obligations to access a transmission tie up to the total capacity transfer capability will allow parties to meet capacity requirements at least cost, and that taking away tie line capability will only make it increasingly difficult to import capacity into areas exhibiting the greatest needs. Constellation further argues that, given that New England's FCM will measure generator performance and availability during the most critical hours of the year for reliability assurance,[28] reliability concerns cannot be met simply by relying on open transmission ties and hoping that capacity becomes available over those transmission resources when called upon during critical hours. Constellation argues that participants' reliability needs are best served by enabling parties to contract for capacity over such transmission ties in advance of critical hours.

27. HQUS asks the Commission to reject the decision to include tie benefits from New York and New Brunswick AC transmission ties in the ICR-reform process. HQUS asserts that proposed section III.12.10 of Market Rule 1 would prohibit capacity imports from New York and New Brunswick in order to leave transmission capacity available for the maximum amount of probabilistic tie benefits, and that this practice prohibits real transactions with New York and New Brunswick in favor of a calculation of the

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[27] Preliminary Minutes of the December 8, 2006 NEPOOL Participants Committee meeting. *See* http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2007/jan52007/supp_notice_jan0507.pdf.

[28] Under the Forward Capacity Market, generation availability will be measured according to "shortage events." This approach is intended to measure generator performance during hours when capacity resources are determined to be most needed due to conditions on the system.

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probability that there will be capacity available in an emergency through reliance on transmission tie benefits. HQUS further argues that as a result of this practice, during a capacity emergency, system operators will rely on a calculation of capacity assistance that an adjacent control area could provide, as opposed to capacity actually under contract and which should, therefore, be more reliable.

28. HQUS further notes that Hydro Quebec Interconnection contracts for capacity have some precedence over tie benefits through the reduction of Hydro Quebec Interconnection Capability Credits (for a transmission owner who has sold its transmission rights). Thus, HQUS asserts that market rules treat the Québec transmission tie differently, allowing real capacity to displace transmission tie benefits, and argues that ISO-NE should treat imports from New York and New Brunswick similarly to the way it treats imports from Québec.[29]

29. National Grid states in its reply that, contrary to protesters' argument that capacity imports provide more reliability and value to market participants than tie benefits, the opposite is true: tie benefits are calculated using extensive probabilistic analysis and independent ISO-NE studies that consider all of the resources that could be present (or absent) at a time of shortage, not just the subset of import contracts, and that tie benefits will ultimately provide more reliability assistance to New England than import contracts.

Commission Decision

30. We will accept ISO-NE's proposal to set aside interface transfer capability for tie benefits. We agree with ISO-NE that since loads within New England jointly share the costs of the transfer capability, loads should jointly share the benefits of that capacity, including the tie benefits and the associated reduction in ICR. Constellation and HQUS object to ISO-NE's proposal to set aside transfer capability associated with the tie benefit; they recommend that the transfer capacity be eligible to support capacity imports even in cases where such imports reduce the tie benefit. But purchasing capacity imports that reduce tie benefits would needlessly increase aggregate capacity costs; it would

[29] As a separate issue, HQUS states that in orders since 2001, the Commission has permitted ISO-NE to assign Hydro-Québec Interconnection Capacity Credits (HQICCs) to the interconnection rights holders (IRHs) based on the IRHs' support of the Phase I/II facilities in New England, rather than based on contractual rights to capacity from Hydro-Québec. HQUS disagrees with this methodology and has pursued its counterarguments in the several prior HQICC proceedings. Since HQUS notes that it is raising this issue simply to note that it is reserving its right to raise this issue in future filings, the Commission will not address this argument here.

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increase capacity purchases from neighboring control areas with no corresponding reduction in the need for capacity purchases within New England, for the following reason.

31. Under ISO-NE's proposal, tie benefits reduce the amount of the ICR. Under the terms of the FCM Settlement Agreement, capacity imports from a specific neighboring control area plus tie benefits from that control area cannot exceed the transfer capability with that control area. Under the rules proposed in the instant filing, LSEs may use only the transfer capability in excess of tie benefits to import capacity. Constellation and HQUS propose that capacity imports, supported by contractual obligations to deliver energy when called upon, should be allowed even when they reduce the amount of tie benefits. But since tie benefits reduce the amount of the ICR, capacity imports that reduce the tie benefit would increase the ICR by the amount of the lost tie benefit. Thus, purchasing imported capacity that reduces the tie benefit would unnecessarily increase the amount of capacity that must be purchased and the associated costs of acquiring capacity by customers in New England.

Treatment of Specific Tie Benefits Provided by Cross-Sound Cable

Protest

32. LIPA asserts that ISO-NE's filing is unjustly discriminatory, in that it does not account in a similar manner for the tie benefits from similarly-situated transmission resources.

33. LIPA states that, under the proposed market rules, section III.12.9 of Market Rule 1 provides that tie benefits with neighboring control areas should be calculated by using a probabilistic methodology that quantifies firm capacity equivalents to express the probable amount of capacity that will be available on the interface. The Cross Sound Cable, an interface between New York and New England on which LIPA owns all of the firm transmission rights, will be subject to this definition. ISO-NE's market rules provide for a different methodology, however, for calculating the tie benefits provided by the Hydro-Quebec Phase II Interconnection (HQ Interconnection) between New England and the Hydro-Quebec control area – namely, a deterministic methodology that uses forecasted load and capacity for the Hydro-Quebec control area and the HQ

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Interconnection transfer limit as determined by ISO-NE to arrive at a specific amount of capacity that will be available for tie benefits on the HQ Interconnection interface.[30]

34. LIPA asserts that these two interties between New England and neighboring control areas are equivalent, in that they are both privately-owned, are both high voltage direct current (HVDC) facilities, function in the same manner (*i.e.*, both the HQ Interconnection and the Cross Sound Cable are direct current (DC) facilities, such that the direction of flows can be controlled), and should therefore have their tie benefits calculated in a similar way. LIPA argues that a similar methodology to measure the tie benefits for both of those facilities (*i.e.*, a deterministic measure that arrives at a definitive result, rather than a probabilistic measure that develops a probable result) is more appropriate for both the HQ Interconnection and the Cross Sound Cable than the probabilistic method for alternating current (AC) interface facilities, where the flows cannot be controlled, contained in the proposed ICR rules, and that it is discriminatory not to calculate the tie benefits provided by the HQ Interconnection and the Cross Sound Cable in a similar manner.

Commission Decision

35. The Commission denies LIPA's request. While LIPA correctly notes that the HQ Interconnection and the Cross Sound Cable are HVDC, controllable interconnections, there are other important differences between the two facilities.

36. ISO-NE is required to submit specific HQ Interconnection values, as required in a prior Commission order.[31] In that order, the Commission noted that the applicants provided that the deterministic method was appropriate there because all of the capacity transferred from the HQ control area to New England are sent through the HQ Interconnection. Thus, the determination of tie benefits available through the HQ Interconnection was based on the availability of all of the generating capacity from

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[30] The difference in treatment here means that parties utilizing the HQ Interconnection will have a higher degree of certainty as to the amount of capacity that will be available to them than parties utilizing the Cross Sound Cable. Thus, transmission capacity across the HQ Interconnection is likely to receive a higher price than transmission capacity across the Cross Sound Cable and other transfer facilities as to which there is a lesser degree of certainty.

[31] *New England Power Pool*, 111 FERC ¶ 61,132 (2005).

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Quebec that can be accessed through the HQ Interconnection, rather than on an estimate of the likelihood that New England would require emergency assistance.[32]

37. Equivalent treatment for the Cross Sound Cable, however, would ignore the fact that when capacity is transferred from New York to New England, that transfer occurs across the Cross Sound Cable and also across other transmission interfaces between the two control areas. Those other transmission interties are AC facilities,[33] so it is not possible to know in advance how much capacity will flow through those facilities. Therefore, it is similarly not possible to know in advance how much transmission capacity on the Cross Sound Cable will be necessary at any given time for emergency assistance. Given this difference, the Commission will not direct ISO-NE to quantify the tie benefits on the Cross Sound Cable in a similar way to its treatment of the HQ Interconnection.

Exports Across a Constrained Region

Protests

38. LIPA states that ISO-NE's filing fails to provide the Market Rules necessary to comply with section III.A.8 of the FCM Settlement Agreement, which states:

> Where zonal separation is determined to exist, Market Rules shall specify a process for an Export both from or through the import-constrained zone over tie lines to external regions.[34]

39. LIPA's interest in this issue stems from its contract with Bear Swamp Power Company LLC (Bear Swamp) to purchase firm capacity and energy from generating capacity located in Massachusetts, for delivery through Connecticut into Long Island by

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[32] *Id.* at P 8.

[33] Those additional facilities are: Pleasant Valley – Long Mountain 345 kV (398) Line, Alps – Berkshire Northfield 345 kV (393/312) Line, Rotterdam – Bear Swamp 230 kV (E205W) Line, Northport – Norwalk Harbor 138 kV (1385) Line, Whitehall – Blissville 115 kV (K37) Line, Hoosick – Bennington 115 kV (K6) Line, and Plattsburgh-Sandbar 115 kV (PV-20) Line. *See* 1992-1996 NYPP – NEPOOL Transfer Limit Study, http://www.iso-ne.com/trans/sys_studies/rsp_stud/other/tfer_limit_study92-96_nypp_nepool.pdf.

[34] LIPA protest at 7, *citing* FCM Settlement Agreement, section III.A.8 at 20.

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way of the Cross Sound Cable (on which LIPA holds 330 MW of firm transmission rights). LIPA argues that properly accounting for capacity that is exported through a constrained zone should result in increasing the Local Sourcing Requirement in the constrained region, but that ISO-NE's filing fails to do so. LIPA also quotes from the testimony of ISO-NE witness, Mark Karl in the *Devon Power, LLC, et al.*, proceeding. There, Mr. Karl testified that firm capacity exports could be accommodated by changing the market rules to allow the export to "buy through" the congestion in the capacity market between the Rest-of-Pool zone and an import-constrained zone such as Connecticut. LIPA is concerned that ISO-NE would be free to prevent such exports, in violation of the FCM Settlement Agreement. Indeed, LIPA states that it has been informed by ISO-NE that the ISO may intend to curtail firm capacity exports during periods of transmission constraints. LIPA also argues that curtailing such firm exports would be a violation of interregional agreements, the provisions of which were approved by the Commission in 2001.[35]

40. ISO-NE and NEPOOL disagree with LIPA, arguing that the provisions in the ICR filing are consistent with the FCM Settlement Agreement. ISO-NE states that the proposed ICR rules appropriately consider any exports by not including capacity associated with an accepted Administrative Export De-List Bid in the calculation of the Local Sourcing Requirement or the ICR. In ISO-NE's view, this latter provision is sufficient to ensure that New England does not rely on capacity obligated for export to a neighboring control area. ISO-NE contends that it is not appropriate, or required by the FCM Settlement Agreement, for a capacity export that originates from a resource located outside of an import-constrained zone to result in an increase in the Local Sourcing Requirement for the import-constrained zone. ISO-NE argues that purchasing capacity from a resource located in an unconstrained zone merely provides a right to use that capacity within the unconstrained zone; it does not provide a priority right to export across any specific path, including a constrained path.

Commission Decision

41. We agree with LIPA that the proposed rules in the instant filing do not provide a process for an Export through an import-constrained zone over tie lines to external regions, as required by the FCM Settlement Agreement. We disagree with ISO-NE that merely excluding such de-listed export capacity from the capacity that may be used to satisfy the ICR and Local Sourcing Requirement is sufficient to meet the FCM Settlement Agreement's requirement. While such exclusion would ensure that New England does not rely on exported capacity in meeting its ICR and Local Sourcing

[35] *See New England Power Pool*, 97 FERC ¶ 61,213 (2001).

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Requirement, as ISO-NE argues, that result does not provide a process to allow entities to export capacity through import-constrained zones.

42. We agree with ISO-NE that an entity purchasing capacity from a resource located in an unconstrained zone is not entitled to export the capacity using constrained transmission capacity for which the entity has not paid for (or otherwise acquired) transmission capacity rights. But ISO-NE's filing provides no process for an entity to acquire such transmission capacity rights. There may be alternative processes that may satisfy the FCM Settlement Agreement's requirement. For example, where transmission constraints could prevent capacity from being exported, one solution might be a process that allows entities to acquire capacity market transmission rights over the applicable congested transmission path at a just and reasonable price. The process described by Mr. Karl of "buying through" the congestion in the capacity market between zones might be such a process.[36] Another process might involve allowing an entity such as LIPA to sell its New England capacity into the FCM auction in the applicable unconstrained zone and to purchase an equivalent amount of capacity in an import-constrained zone (*i.e.*, Rest-of-Connecticut, in LIPA's case) in the FCM. LIPA could then move the purchased capacity over the tie line (*i.e.*, the Cross Sound Cable) into Long Island without relying on congested transmission capacity in New England. Such a purchase would be in addition to the capacity purchased to meet the capacity requirements of LSEs in the import-constrained zone. As a result, the minimum amount of capacity required to be purchased in the FCM in the import-constrained zone would exceed the Local Sourcing Requirement by the amount of the purchase for export. There may be other options that would satisfy the FCM Settlement Agreement's requirement.

43. We will not specify in this order how the FCM Settlement Agreement's requirement must be satisfied, but we will require that ISO-NE file to propose a process for such exports within 180 days of the date of this order.[37] We do not agree with what appears to be LIPA's recommendation to increase the Local Sourcing Requirement of the import-constrained area by the amount of the export at no cost to the exporter. To the extent that such capacity exports involve use of constrained transmission capacity, the exporter should pay a just and reasonable price for the transmission capacity.

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[36] To the extent that an entity acquired transmission capacity market rights through an import-constrained zone, the Local Sourcing Requirement in the import-constrained zone may need to increase, since less capacity could be imported from unconstrained zones to meet the reliability needs of loads within the import-constrained zone.

[37] The Commission's decision here renders moot LIPA's request for a technical conference.

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Use of "As Is" versus "At Criterion" Standard

Protests

44. ISO-NE states that “as is” and “at criterion” are two ways of modeling neighboring areas to determine the tie benefits modeled in the ISO-NE Installed Capacity Requirements LOLE model. “As is” assumes that neighboring areas will have resources and demands equal to those forecasted for the capacity period. These forecasted resources and demands could be more or less than those needed to meet the reliability standard of 0.1 LOLE. “At criterion” assumes that neighboring areas will have enough resources so that each area separately meets the reliability standard of 0.1 LOLE based on forecasted load for the capacity period.

45. ISO-NE proposes to use “at criterion” for the 3-year ahead capacity period and “as is” for the reconfiguration auction 2 months prior to the capacity period. ISO-NE argues that "at criterion" assumptions are appropriate for the long-range planning associated with the 3-year-ahead auction because there is much less certainty that a capacity surplus or deficiency will exist in a neighboring area. By contrast, according to ISO-NE, since the reconfiguration auction will occur only two months before the Power Year, "as is" assumptions are likely to more accurately reflect the resources that will actually be available during the Power Year.

46. The NYSRC is concerned with ISO-NE’s proposal to assume "as is" assumptions for capacity levels in neighboring control areas in the process of determining New England’s annual ICR. The NYSRC argues that this modeling approach will result in unreasonably low New England ICR, diminish the reliability of neighboring control areas, such as New York, and would result in New York ratepayers subsidizing New England. For example, NYSRC contends that modeling the New York control area under “as is" assumptions produces a capacity margin of approximately 30 percent rather than 16.5 percent design level for 2007. Finally, the NYSRC is concerned that the ISO-NE filing makes no reference to a Joint Tie Benefit study that has been undertaken jointly by the NYSRC/NYISO and ISO-NE, which includes an evaluation and determination of the level of emergency assistance that New York and New England can provide to one another. The NYSRC asserts that the Commission should direct ISO-NE to reconsider the use of the “as is” approach and to submit its proposal for discussion in the context of the Joint Tie Benefit study.

47. The NYSRC is equally concerned with ISO-NE’s proposal to ignore firm export capacity commitments when determining ICR and locational requirements. The NYRSC states that the curtailment of firm capacity contracts is inconsistent with NYISO market rules and may jeopardize ISO-NE participation in the NYSIO market. The NYSRC

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argues that this issue should be resolved jointly as part of ongoing NYSRC/NYISO/ISO-NE Joint Tie Benefit study.

48. National Grid in its reply comments states that it is appropriate to use the "as is" measurement as the capacity period approaches because that approach more closely reflects the reality of the capacity available to New England from neighboring control areas, including both capacity excess and capacity shortages.

Commission Decision

49. We agree with ISO-NE that it is appropriate to use “as is” for the Annual Reconfiguration Auction two months before the Capacity Commitment period. This allows the reconfiguration auction to more accurately reflect the ICR needed to ensure that there is enough generation to reliably meet load in New England without over-relying on neighboring capacity and without overcharging New England customers for unnecessary capacity. We do not agree with NYSRC’s argument that this will be detrimental to reliability in New York. As ISO-NE explained in its reply comments, the “as is” criterion will still limit tie benefits to the physical capacity of the tie lines minus firm capacity imports, and it only allows increased use of tie benefits to the extent that there is capacity available above the “at criterion” level in neighboring areas. In addition, we recognize that a new generator generally cannot be built within a two month period, so the “as is” criterion is reasonable for this short time period. By contrast, there is more uncertainty as to what generators will be built or retired in the three-year period where the “at criterion” assumption is used, and thus use of the "at criterion" assumption is a reasonable approximation of the expected capacity situations in neighboring areas for the 3-year forward auction.

50. We also agree with the ISO-NE that the Joint New England/New York reliability study is to provide guidance, and ISO-NE is not obligated to operate according to the assumptions of the study. We recognize this as an important effort, and encourage the ISOs to continue to jointly study the impacts of their tie benefits assumptions.

Internal Constraints

Protests

51. Con Ed argues that the proposed ICR methodology ignores internal transmission constraints when calculating the level of tie benefits used to determine the overall system-wide ICR. Con Ed notes that in determining Local Sourcing Requirements, the proposed rules consider internal transmission constraints and argues that the same consideration should be made when determining the level of tie benefits. Con Ed argues that the proposed ICR rules ignore the possibility that the available resources may be

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constrained by internal transmission limits, and therefore unable to transmit their output to the necessary load centers. Con Ed further argues that this approach automatically assumes that there will be support available from the broader ISO-NE market and will produce an understated ICR. Finally, Con Ed contends that ISO-NE has conducted studies that clearly demonstrate that tie benefits are heavily dependent on internal transmission constraints.[38]

52. In its answer, ISO-NE argues that the Commission should deny Con Ed's protest. ISO-NE asserts that Local Sourcing Requirements will be used to ensure that there is adequate capacity in import-constrained zones. ISO-NE states that during the calculation of Local Sourcing Requirements, tie benefits are assumed to accrue in the New England zone to which the interface interconnects. Thus, ISO-NE asserts, capacity is distributed in such a way to alleviate internal constraints.

Commission Decision

53. The Commission will not direct ISO-NE to revise its proposed approach to calculating the level of tie benefits at this time. Con Ed has raised this issue in previous proceedings in which ISO-NE has filed the annual ICR level. In the proceeding covering the 2006/2007 power year, Con Ed made substantially the same argument. In that proceeding, the Commission not only found that the resulting ICR level was just and reasonable, it did not direct ISO-NE to model internal constraints into the determination of tie benefits.[39] ISO-NE and NEPOOL assert that the proposed rules in the instant filing merely modify existing ICR processes in order to accommodate the FCM. Con Ed has not demonstrated why its requested approach to calculating tie benefits is required to accommodate the FCM, particularly given that the Commission has previously found that the approach embodied in the proposed rules has produced just and reasonable results.

Additional Issues raised by CT DPUC

Protest

54. CT DPUC challenges a number of definitions and concepts contained in the ISO-NE/NEPOOL filing. The Commission's rulings on those challenges are below.

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[38] Con Ed states that in a 2003 presentation, ISO-NE indicated that summer tie benefits could range from 50 MW to nearly 3,000 MW, depending on the extent to which ISO-NE modeled constraints. *See* Con Ed protest at 6.

[39] *ISO New England, Inc*. 115 FERC ¶ 61,149 (2006).

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1. Definition of Existing Capacity Resource

55. Among the modifications to the ISO-NE tariff is the addition of a definition for an "Existing Capacity Resource" as :

> any resource that does not meet any of the eligibility criteria to participate in the forward Capacity Auction as a New Capacity Resource, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

56. The CT DPUC argues that the FCM Settlement Agreement provides that a new capacity resource may elect to be treated as an Existing Capacity Resource. Thus, the CT DPUC asks that the proposed definition be revised to state that a new capacity resource may be required to be treated as an Existing Capacity Resource pursuant to contract requirements or for other reasons, and seeks the addition of the following language at the end of the last sentence above:

> . . . or that is not within 12 months of its requested commercial operations date but is required pursuant to contract or otherwise elects to be treated as an Existing Capacity Resource.[40]

57. In its answer, ISO-NE argues that the intent of the proposed definition is to allow a new capacity resource to be treated as an Existing Capacity Resource in the Forward Capacity Market, and additionally, that the forthcoming rules governing the operation of the Forward Capacity Market will provide a description of how a new capacity resource can be classified as an Existing Capacity Resource if it elects to do so as required contractually or otherwise.

58. The Commission finds that the definition proposed by the CT DPUC appears to reflect the intent of the FCM Settlement Agreement, and the definition provided by ISO-NE in its filing does not accomplish this purpose. Moreover, the Commission notes that ISO-NE and the CT DPUC appear to agree that the definition of an Existing Capacity Resource should reflect the idea that a new capacity resource may elect to be treated as an Existing Capacity Resource for contractual or other reasons. The Commission directs ISO-NE to revise the definition of an Existing Capacity Resource either as proposed by the CT DPUC or in such a way that it clearly articulates that a new capacity resource may elect to be treated as an Existing Capacity Resource. We will therefore require ISO-NE

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[40] CT DPUC protest at 13.

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and NEPOOL to revise the definition of an Existing Capacity Resource, as discussed above, within 30 days of the date of this filing.

2. Definition of Permanent De-list Bid

59. Another modification to the ISO-NE tariff is the addition of a definition for a "Permanent De-list Bid." The proposed definition states that a Permanent De-list Bid "is a bid submitted in the Forward Capacity Auction by an Existing Capacity Resource to permanently de-list capacity." The CT DPUC asserts that the definition proposed in the instant filing is merely a tautology and provides no definition for permanently de-listed capacity. The CT DPUC argues that the FCM Settlement Agreement, at section 11.III.D.3, provides an accurate and useful definition and that the proposed definition should be modified to comport with the FCM Settlement Agreement.

60. In its answer, ISO-NE states that a detailed definition of Permanent De-list Bids will be provided in the FCM market rules, so the CT DPUC's request that the Commission order the ISO to adopt a more detailed definition of "Permanent De-List Capacity" should be denied.

61. The Commission agrees with the CT DPUC and finds that the definition as proposed by ISO-NE is insufficient. We further find that the language within the FCM Settlement Agreement provides for a fuller description of Permanent De-list Bids. While it may be true that ISO-NE will file a more detailed definition in a subsequent filing, that filing has not yet been presented to the Commission and, as such, we cannot rely on that subsequent filing in place of a fuller definition for the purposes of the proposed rule. We will therefore require ISO-NE and NEPOOL to provide a fuller description of Permanent De-list Bids, as discussed above, within 30 days of the date of this filing.

3. Modeling Capacity Zones Using "As is" Assumptions

62. As discussed above, the proposed rules in the instant filing describe the establishment of Local Sourcing Requirements, which identify the minimum number of MWs an import-constrained sub-region must procure in an FCM auction. The CT DPUC notes that none of the proposed rules in the instant filing expressly specifies that resources in the import-constrained sub-regions and the rest of the New England control area will be modeled using "as is" assumptions. The CT DPUC states that its understanding is that, with regard to proposed section III.12.6, the use of "as is" assumptions is implicit, but it argues that the Commission should state that ISO-NE will use "as is" assumptions for the purposes of modeling all resources in all auctions, except for the modeling tie benefits for specified auctions. The CT DPUC asserts that the use of "at criterion" assumptions for resources in Connecticut and the rest of the New England control area could be extremely detrimental for Connecticut.

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63. In its answer, ISO-NE states that there is no need for the requested clarification. ISO-NE notes that, under proposed section III.12.2 of the ICR Rules, all resources (pursuant to section III.12.7) will be included in the modeling assumptions for determining Local Sourcing Requirements. ISO-NE states that this includes all resources that are expected to be available plus additional units that may be needed to meet the LOLE criterion. ISO-NE argues that these provisions describe a calculation that is (as much as is possible more than three years in advance) an "as is" calculation based on the best estimate of resources that are expected to be available.

64. The Commission will not direct ISO-NE to make the requested changes. The Commission agrees with ISO-NE's answer and finds that the proposed rules reflect the use of "as is" assumptions in modeling capacity zones. Section III.12.2.1 of the ICR Rules states that, for the purposes of calculating import-constrained zones, the load zone under study (as well as the rest of the New England control area) will include "all load and all resources electrically located within the zone."

4. Transmission Interface Limits

65. Section III.12.5 of the proposed rules states that:

> The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

66. The CT DPUC asserts that transmission interface limits are a crucial input for determining Local Sourcing Requirements and argues that material aspects of that analysis should not be relegated to ISO-NE's Manuals and Administrative Procedures. CT DPUC argues that the basis for ISO-NE's determination of interface limits, whether in the tariff or in manuals and administrative procedures, should be subject to Commission review and stakeholder challenge under section 205 of the FPA. Thus, the CT DPUC asserts, the Commission should clarify that any change to ISO-NE's manual or administrative procedures that affects its analysis of transmission interface limits substantially affects rates and must be filed with the Commission under section 205.

67. In its answer, ISO-NE states that the CT DPUC's request should be denied. ISO-NE states that it will continue to make its annual ICR-values filings with the Commission. ISO-NE asserts that in establishing the ICR values, there will be a detailed review before stakeholders and the Commission of the various factual determinations reflected in the annual filing. Thus, ISO-NE concludes, any and all points of contention

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regarding the annual ICR filing, including the determination of transmission interface limits, can be addressed at that time.

68. The Commission will not direct ISO-NE to file changes to manuals or administrative procedures that affects analysis of transmission interface limits with the Commission under section 205. The Commission finds that, insofar as ISO-NE and stakeholders continue to develop and file with the Commission annual ICR values, the CT DPUC will have an opportunity to address transmission interface limits that are inputs into the determination of ICR values. Moreover, the Commission notes that the proposed rules provide for participation from state regulatory agencies in a portion of the ICR development process that affects transmission interface limits. Section III.12.5 of the proposed rules states that prior to each auction, ISO-NE will update transmission interface limits, accounting for "any additional transmission projects and elements of transmission projects that are added to the network model." The proposed rules further state that during the process of making transmission infrastructure determinations to be included in the network model, ISO-NE will "consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies." The Commission finds that the combination of the annual ICR filing and the opportunity for state regulatory agencies to participate in the process affords them sufficient opportunity to address any interface issues. Thus, a further filing is not required.

5. Establishing the Network Transmission Model

69. Section III.12.6.2 of the proposed rules lists the initial milestones that transmission projects must meet in order to be considered in service. ISO-NE will determine whether transmission projects or elements of transmission projects meet all of the following requirements:

a) A "critical path schedule" for the transmission project, provided to ISO-NE that shows that the transmission project will be in-service no later than the first day of the relevant capacity period;

b) At the time of review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule;

c) At the time of review, engineering is on schedule as shown on the critical path schedule;

d) At the time of review, land acquisition, if required, is on schedule as shown on the critical path schedule;

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e) Certification from a transmission company's officer that the schedule is achievable and the owner intends to build in accordance with that schedule; and

f) For a transmission project that meets the initial threshold milestones specified above, ISO-NE will consider the other factors and "any other relevant information" to determine whether to include the transmission project in the network model for a specific capacity period.

70. The CT DPUC asserts that these criteria are too rigid and may exclude transmission resources that will, in fact, be in place to reduce ICR or a Local Sourcing Requirement, which may result in customers being required to purchase a greater amount of capacity than is truly necessary. The CT DPUC is primarily concerned that criteria (b)-(d) could be used to exclude a transmission project from the network model based solely on immaterial deviations from its projected schedule. The CT DPUC argues that delays in siting, permitting, engineering, and land acquisition may not necessarily change a project's in-service date. Thus, the CT DPUC continues, in adopting an inflexible rule that automatically disqualifies projects from consideration if any of these activities are behind schedule, ISO-NE would ignore the real impact delays in those activities may have on project completion.

71. Moreover, the CT DPUC asserts that in imposing an absolute set of criteria for including a transmission project in the network model, ISO-NE's proposed rule would disregard the significance of any schedule slippage and may not consider a project because of a very small delay that is insignificant for the overall project. The CT DPUC also contends that many projects have contingency plans, which allow them to recoup delays (*e.g.*, by adding extra workers or hours) and fulfill the project schedule. The CT DPUC states that ISO-NE's proposed rule would mechanically exclude any project that misses any milestone date without regard to its real consequences for the project. The CT DPUC asserts that section III.12.6.3 allows ISO-NE some flexibility in evaluating probable in-service dates and asks that the Commission to move factors (b)-(d) from to section III.12.6.3 so that ISO-NE can apply appropriate flexibility to assess whether a transmission project will be in-service by the start of the relevant capacity period.

72. In its answer, ISO-NE argues that threshold requirements in proposed section III.12.6.2 are not overly restrictive and that the CT DPUC's request should be denied. ISO-NE states that these criteria were carefully drafted so as to enable the ISO to ensure the accuracy of the in-service dates of the projects upon which its transmission network model will be based. Furthermore, ISO-NE contends that were it to forecast a particular date and the transmission resource failed to be in place in time, system reliability could be severely imperiled. Finally, ISO-NE contends that, given that transmission projects lack the financial assurances of generation projects in the New England, it is even more necessary to subject such projects to a well-defined standard.

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73. The Commission will not direct ISO-NE to modify its tariff as requested by the CT DPUC. The Commission finds that the proposed milestones identified in section III.12.6.2 represent reasonable and identifiable initial markers to determine whether a transmission project may be included in the network model. Moreover, the Commission finds that they provide adequate certainty with regard to creating the network model and thus the actual ICR. The Commission finds that relaxing the proposed milestones would only serve to add uncertainty to the model. The Commission further finds that the milestones articulated in the proposed rule are not restrictive. We believe that a record that shows that siting and permitting, engineering and land acquisition processes are on schedule provides ISO-NE with an appropriate set of thresholds by which to judge the progress of transmission projects.

6. Definition of "Capacity Zone"

74. The CT DPUC claims that the definition of "Capacity Zone" in section III.1.3 of Market Rule 1 is potentially inconsistent with other parts of the proposed rules. Specifically, the CT DPUC notes that multiple sections[41] of the proposed rules each make the electrical location of a resource controlling, not its geographic location, as is asserted in the definition of "Capacity Zone." The CT DPUC therefore requests that the definition of "Capacity Zone" be changed to "an electrical sub-region of the New England Control Area, as determined in accordance with sections III.12.4 of this Market Rule."[42]

75. We disagree with the CT DPUC regarding the definition of "Capacity Zone." The CT DPUC is correct that the electrical location of a resource should be controlling in defining a Capacity Zone; however, Market Rule 1 already provides for an accurate definition of Capacity Zone. As ISO-NE points out in its Answer, proposed section III.12.4 of Market Rule 1 explains that Capacity Zones will be modeled as export-constrained, import-constrained and adjacent "Load Zones," which are defined as "Reliability Regions, except at otherwise provided for in section III.2.7 of this Market Rule."[43] "Reliability Regions" are regions "identified on [ISO-NE's] website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System,"[44] *i.e.*, the electrical

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[41] See sections III.12.2, III.12.2.2.1(d), III.12.2.2(a), and III.12.7.3.

[42] CT DPUC protest at 13.

[43] ISO-NE's Answer at 36, *citing* section III.1.3 of Market Rule 1.

[44] *Id.* at 37, *citing* section III.1.3 of Market Rule 1.

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location of a resource is controlling. We therefore reject CT DPUC's requested definition of "Capacity Zone" as unnecessary.

7. Definition of "Loss of Load Expectation"

76. The CT DPUC protests ISO-NE's definition of "Loss of Load Expectation." Specifically, the CT DPUC claims that ISO-NE has provided an incomplete definition of the term that fails to convey the full scope of the Northeast Power Coordinating Council resources adequacy design criterion. As such, the CT DPUC requests that the definition of "Loss of Load Expectation" be revised to reflect the same definition provided by the Northeast Power Coordinating Council.

77. We disagree with the CT DPUC that the definition of "Loss of Load Expectation" should be expanded to reflect the Northeast Power Coordinating Council definition *verbatim*. The ICR Rule explains ISO-NE's method for calculating the ICR in relation to Loss of Load Expectation criterion and is more complicated than the Northeast Power Coordinating Council definition. ISO-NE's definition of "Loss of Load Expectation" serves the purpose of the ICR Rule in explaining how ISO-NE has implemented the Loss of Load Expectation criterion. As such, it is unnecessary to require ISO-NE to conform its definition of "Loss of Load Expectation" to exactly match the Northeast Power Coordinating Council definition.

8. Calculation of Local Sourcing Requirements

78. The CT DPUC claims that in modeling external Control Area support from tie benefits, the proposed rule is not clear that Connecticut's Local Sourcing Requirement should reflect the locational tie benefits that accrue from the Cross Sound Cable and 1385 Cable. The CT DPUC claims that ISO-NE should clarify that the tie benefits attributable to the Cross Sound Cable and 1385 Cable are to be assigned to Connecticut in assessing the Connecticut's Local Sourcing Requirement, not to the entire New England region. The CT DPUC claims that the Cross Sound Cable and 1385 Cable provides a valuable reliability contribution to the Connecticut load zone specifically. The CT DPUC points out that the Initial Decision in *Devon Power*[45] recommended that ISO-NE "be required to calculate Connecticut's capacity transfer limits to reflect the reliability benefits provided by the Cross Sound and 1385 Cables."[46]

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[45] *Devon Power LLC*, 111 FERC ¶ 63,063 (2005) (*Devon Power* Initial Decision).

[46] CT DPUC Protest at 15, *citing Devon Power* Initial Decision at P 743.

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79. The Commission finds CT DPUC's requested clarification unnecessary. The ICR Rule already provides for the inclusion of tie benefits on the import-constrained side of the interface in the calculation of Local Sourcing Requirements, if any such tie benefits exist.[47] The proposed revisions to the ICR Rule further require ISO-NE to engage in a study of tie benefits at least once every three years, and the results of the study must be updated if conditions in the New England Control Area or neighboring Control Areas change.[48] We find the existing ICR Rules and the proposed changes to the ICR Rules sufficient to appropriately apply all applicable tie benefits attributed to the Cross Sound Cable or 1385 Cable in calculating Connecticut's Local Sourcing Requirement.

80. The CT DPUC also specifically requests that the Commission ensures that all tie benefits from the Cross Sound Cable and the 1385 Cable be applied solely to the calculation of Connecticut's Local Sourcing Requirement and not be considered a regional benefit to be applied to the entire New England region.

81. The Commission denies the CT DPUC's request for this ruling. First, a showing has yet to be made that the Cross Sound Cable and/or 1385 Cable provides a unique reliability benefit to the New England Control Area or the Connecticut Load Zone. While the Cross Sound Cable and 1385 Cable do provide transmission between New England/Connecticut and Long Island, capacity benefits of that tie can only accrue to New England if Long Island has an ample surplus of capacity. As explained by ISO-NE in its Answer, the New York ISO currently requires Long Island to satisfy 99 percent of its peak installed capacity requirements with local resources which leaves Long Island with only "marginal excess."[49] Long Island's thin capacity margin, combined with the lack of evidence that New England/Connecticut has enjoyed a unique reliability benefit from the Cross Sound Cable and/or the 1385 Cable, removes any base for specifically assigning tie benefits to the Connecticut Load Zone uniquely attributable to the Cross Sound Cable and/or 1385 Cable.

82. The Commission has consistently found that the Cross Sound Cable, in particular, has not been shown to provide any unique capacity reliability benefit to the New England Control Area. In the 2005 order accepting ISO-NE's ICR for the 2005/2006 power

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[47] Section III.12.2.1 of Market Rule 1.

[48] Proposed section III.12.9 of Market Rule 1.

[49] ISO-NE Answer at 24, citing testimony of LIPA witness Bolbrock in *Devon Power LLC*, Docket No. ER03-563-030, Tr. at 3791:19-25.

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year,[50] the Commission found that ISO-NE's study supported tie line benefits of 2000 MW for the 2005/2006 Power Year.[51] However, the Commission did not attribute any part of that 2000 MW tie benefit to a specific Load Zone; rather, the tie benefit was assigned to the entire New England region and the benefit itself was calculated considering all ties with the New York Control Area.

83. In the order on rehearing of the 2005 ICR Order, the Commission stated that "there is nothing in the record that indicates that any portion of the 600 MW tie line benefit assigned to [the New York Control Area] that was included in the February 2003 Tie Reliability Benefits Study was attributable to the Cross Sound Cable."[52]

84. The CT DPUC's reliance on the *Devon Power* Initial Decision in support of its position on tie benefits from the Cross Sound Cable and 1385 Cable is misplaced. In the *Devon Power* Initial Decision, the administrative law judge "recommend[ed] that the Commission direct the ISO to recalculate [capacity transfer limits] for [Connecticut] to reflect the reliability benefits provided by the cables."[53] This recommendation was grounded in the assumption that the ICR values established in the 2005 ICR Order ascribed tie benefits to the Cross Sound Cable and 1385 Cable. In fact, the 2005 ICR Order made no such finding. At no point in that order did ISO-NE determine tie benefits attributable to the Cross Sound Cable or the 1385 Cable, and at no point did the Commission accept such an assertion. Rather, the 2005 ICR Order accepted tie benefits attributable to all ties between the New York Control Area and the New England Control Area. The administrative law judge's recommendation in the *Devon Power* Initial Decision on which the CT DPUC seeks to rely, therefore, was based on an erroneous assumption that the Cross Sound Cable and 1385 Cable provide specific reliability

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[50] *See ISO New England, Inc.*, 111 FERC ¶ 61,185 (2005 ICR Order), *reh'g. denied*, 112 FERC ¶ 61,254, (2005), *appeal pending sub nom. Connecticut Department of Public Utility Control* v. *Federal Energy Regulatory Commission (CT DPUC)*, U.S.C.A., D.C. Circuit, Docket No. 05-1411.

[51] 2005 ICR Order at P 30.

[52] 112 FERC ¶ 61,254 at P 14.

[53] *Devon Power* Initial Decision at P 743.

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benefits to Connecticut,[54] rather than making a specific finding in that regard, as CT DPUC implies.

9. Determination of Capacity Zones

85. The CT DPUC asserts that section III.12.4(b) of the proposed ICR Rules will incorrectly establish the total amount of projected installed capacity that will be available at the start of the Capacity Commitment Period and does not reflect the terms of the FCM Settlement Agreement. Specifically, the CT DPUC claims that ISO-NE has failed to include Intermittent Resources and New Capacity Resources that are "on track for completion by the start of the first Capacity Commitment Period."[55] The CT DPUC claims that the FCM Settlement Agreement recognized the need for special rules in the ICR methodology applicable to Intermittent Resources.[56] The CT DPUC also claims that proposed section III.12.7.2 of the ICR Rules should be revised to include all resources, including Intermittent Resources and New Capacity Resources, that are expected to be in service by the first day of the relevant Capacity Commitment Period.

86. The CT DPUC's assertion that Intermittent Resources are not considered in the assessment of project installed capacity is unfounded. As ISO-NE points out in its Answer, Intermittent Resources are considered to be "Resources," as defined in Market Rule 1. A "Resource" is defined in Market Rule 1 as, among other things, "a generating unit;"[57] this definition includes Intermittent Resources. As such, all generating units, including Intermittent Resources, will be included in ISO-NE's assessment of projected installed capacity. It is therefore unnecessary to require ISO-NE to alter proposed Rule III.12.4(b) as requested by the CT DPUC.

87. The CT DPUC's claim that ISO-NE failed to comply with the FCM Settlement Agreement's requirement to include New Capacity Resources qualified by ISO-NE for the FCM that are on track to be completed by the start of the first Capacity Commitment Period in the calculation of ICR is also baseless. The proposed ICR Rules dictate that all Existing Capacity Resources will be included in the calculation of ICR. "Existing Capacity Resources" includes resources that are under construction and within 12 months

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[54] The *Devon Power* case was ultimately resolved through a settlement which did not address the specific contentions of P 743; *see* FCM Orders.

[55] CT DPUC Protest at 19.

[56] *Id.* citing FCM Settlement Agreement, section 11.II.E.1.a.

[57] Section III.1.3 of Market Rule 1.

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of the expected commercial operations date, subject to review by ISO-NE.[58] Thus, those new resources that are within 12 months of commencement of expected commercial operations will be treated as Existing Capacity Resources for the first Capacity Commitment Period.

88. We also disagree with CT DPUC's requested modification of proposed Rule III.12.7.2 to include all Intermittent Resources and New Capacity Resources that qualify for the FCM in the calculation of ICR. As explained above, Intermittent Resources are considered "Resources" and so will be included in the ICR calculation. New Capacity Resources, however, are resources that do not yet have an obligation to commence operations by the start date of the relevant Capacity Commitment Period; rather, these resources have simply made a show of interest. ISO-NE should not rely on resources that have yet to receive an obligation to provide capacity by clearing in an auction in calculating ICR. Doing so would introduce an unnecessary risk of overstating the actual reliability of the New England system by assuming a level of capacity supply that may not all be operational at the start of the Capacity Commitment Period. ISO-NE's proposed ICR Rule appropriately adopts a more conservative and reliable approach by including only those resources that have an obligation to provide capacity in the relevant Capacity Commitment Period. The CT DPUC's request for modification is therefore rejected.

10. Generation Modeling Assumptions

89. The CT DPUC protests ISO-NE's proposal to include in its network model only those new generating units that have

> a valid Interconnection Request for which a draft Interconnection Feasibility Study report has been submitted to the Interconnection Customer and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period whether or not such unit is participating in the Forward Capacity Market qualification process.[59]

90. The CT DPUC claims that ISO-NE's completion of a draft Interconnection Feasibility Study report is not a relevant criterion for determining whether a new resource will be in service by the start of a Capacity Commitment Period. The CT DPUC argues that ISO-NE's proposed Generation Modeling Assumptions will require a new generating

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[58] *Id.*

[59] Proposed section III.12.6(a)iii of Market Rule 1.

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resource to submit an Interconnection Request about four and a half years before the relevant Capacity Commitment Period in order to be included in ISO-NE's network model. The CT DPUC claims that many new generating units and capacity additions to existing facilities have a much shorter lead time and could not be reasonably expected to submit Interconnection Requests so far in advance.

91. The CT DPUC also argues that the requirement for a draft Interconnection Feasibility Study so far in advance of the Capacity Commitment Period may be inconsistent with the qualification criteria for the FCA since the FCA qualification rules do not require an Interconnection Request or Interconnection Feasibility Study.

92. The CT DPUC therefore asserts that the only relevant basis for determining whether a generating resource is expected to be in service for a Capacity Commitment Period should be qualification for the FCA, *i.e.*, if a unit has met the qualification requirements for the FCA, it should be included in ISO-NE's network model for purposes of determining ICR and Local Sourcing Requirements.

93. The CT DPUC's interpretation of the network model generated by proposed section III.12.6(a)iii of the ICR Rules seems to be based on a misunderstanding of the purpose of the network model. As ISO-NE explains in its Answer, the purpose of this portion of the ICR Rules is to set transfer limits and handle interconnection requests, not to determine which units are assumed to be available to meet a Local Sourcing Requirement. ISO-NE will address this issue in its forthcoming FCM rules filing.

94. Further, a draft Feasibility Study is necessary in order to produce an accurate network model. As ISO-NE explains in its Answer, a network model is essentially an electronic representation of the transmission system, including all transmission lines, breakers, and substations. Interconnections potentially alter the network model, depending on if any new equipment is added to the system, *e.g.*, additional breakers. These material changes to the transmission system may affect transfer limits and/or the feasibility of other interconnection projects. Only a draft Interconnection Feasibility Study conveys any material modifications to the transmission system as a result of a new generating unit's interconnection. Without that information, ISO-NE will be unable to accurately generate a network model. We will therefore reject the CT DPUC's request for modification of the proposed Generation Modeling Assumptions section of the ICR Rules.

11. <u>Tie Benefits Study</u>

95. The CT DPUC requests that the Commission require ISO-NE to perform a new tie benefits study if there is a change to the Northeast Power Coordinating Council-area electrical system that may materially affect tie benefits in the New England Control Area.

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96. The proposed ICR Rules already provide for the relief the CT DPUC is requesting. Under the proposed ICR Rules, ISO-NE must update its tie benefits study if ISO-NE "determines that New England Control Area or external Control Area system conditions may change the results from the study."[60] As such, we will reject the CT DPUC's requested modification as unnecessary.

The Commission orders:

(A) The Commission hereby accepts the filing, with the modifications discussed above.

(B) The Commisison hereby requires ISO-NE file to propose a process for such exports as LIPA's export of capacity from Bear Swamp, *supra*, or explain why that established by the proposed rules in the instant filing and the subsequent FCM rules would address LIPA's concerns, within 180 days of the date of this order.

(C) The Commission hereby requires ISO-NE and NEPOOL to revise the definition of an Existing Capacity Resource, and to provide a fuller description of Permanent De-list Bids, as discussed above, within 30 days of the date of this filing.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

[60] Proposed section III.12.9 of Market Rule 1.