103 FERC ¶ 61,304
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, and Nora Mead Brownell.

New England Power Pool and ISO New England, Inc.	Docket Nos. ER02-2330-004, ER02-2330-006, ER02-2330-007, ER02-2330-008 and EL00-62-054
ISO New England, Inc.	Docket No. ER00-2052-001
ISO New England, Inc.	Docket No. EL00-62-036

ORDER ON REHEARING AND
ACCEPTING IN PART AND REJECTING IN PART
COMPLIANCE FILINGS

(Issued June 6, 2003)

1. In this order, the Commission grants in part and denies in part requests for clarification and/or rehearing filed in response to our order on the Standard Market Design filed by the New England Power Pool Participants Committee (NEPOOL) and ISO New England, Inc. (ISO-NE). We also accept in part and reject in part three compliance filings regarding that market design. Customers in New England will benefit from this order because it further facilitates the implementation of effective market rules in New England.

BACKGROUND

2. On September 20, 2002, the Commission issued an order accepting a new Standard Market Design for New England (NE-SMD).[1] Among other provisions, in order to send correct market signals as to congestion, NE-SMD implemented Locational

---

[1] New England Power Pool and ISO New England, Inc., 100 FERC ¶ 61,287 (2002) (September 20 Order).

Marginal Pricing (LMP) for New England. We also accepted a plan by which ISO-NE would designate areas in New England as Designated Congested Areas (DCAs), and create a "safe harbor" bid within those areas based on the price needed to recover the annual cost of a new combustion turbine unit (proxy CT) over the number of hours it would be expected to operate during the year.

3. Several parties sought rehearing. On December 20, the Commission issued an order granting rehearing in part and denying rehearing in part, and accepting two compliance filings.[2]

4. A request for reopening the record and reconsideration of that order was filed by the Connecticut Department of Public Utility Control (CT DPUC). Timely requests for clarification and/or rehearing of the December 20 Order were filed by Central Maine Power Company (Central Maine), the Maine Public Utilities Commission, Maine Public Advocate, Rhode Island Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, and the Attorney General of Rhode Island (Maine/RI Commissions), Massachusetts Department of Telecommunications and Energy (Mass DTE), National Grid USA (National Grid), NEPOOL, Northeast Utilities Service Company and Select Energy (NU), the NRG Companies (NRG), NSTAR Electric and Gas Corporation (NSTAR), TransCanada Power Marketing, Ltd. (TCPM), and Vermont Department of Public Service (VDPS).

5. Responses to CT DPUC's request for reopening and reconsideration were filed by Central Maine, ISO-NE, Mass DTE, and Maine/RI Commissions. Responses to the requests for clarification and/or rehearing were filed by the Attorney General of Connecticut (CTAG), ISO-NE, and NU.

6. NEPOOL and ISO-NE made compliance filings on December 20, 2002 (Docket No. ER02-2330-004),[3] January 21, 2003 (Docket No. ER02-2330-007), and January 28, 2003 Docket No. ER02-2330-008). The December 20 filing was published in the Federal Register with interventions, comments and protests due on or before January 10, 2003.[4] The January 21 compliance filing was published in the Federal Register with

[2]New England Power Pool and ISO New England, Inc., 101 FERC ¶ 61,344 (2002) (December 20 Order).

[3]This was a compliance filing to the September 20 Order.

[4]68 Fed. Reg. 764 (2003).

interventions, comments and protests due on or before February 11.[5] The January 28 compliance filing was published in the Federal Register with interventions, comments and protests due on or before February 18.[6] On February 7, 2003, ISO-NE filed a supplement to its January 28 filing, in which it sought the authority to suspend the operation of the DCA threshold.[7]

7. Motions to intervene in this proceeding were filed by the Maine Public Advocate, the Attorney General of Massachusetts (Mass AG), Bay State Consultants, CT DPUC, and Energy Options Consulting Group. Comments to the December 20 compliance filing were filed by the New England Conference of Public Utilities Commissioners (NECPUC). In response to the January 21 compliance filing, the Connecticut Municipal Energy Cooperative (CMEEC) moved to intervene, National Grid filed a protest, and PG&E National Energy Group et al. (PG&E) filed an answer to National Grid's protest. Protests and comments regarding the January 28 compliance filing were filed by CTAG, CT DPUC, CMEEC, ISO-NE and NEPOOL, Mass AG, Mass DTE, New England Suppliers (NE Suppliers), NU, NSTAR, PSEG Power LLC et al. (PSEG), and, filed separately, the Massachusetts towns of Billerica, Brookline, Burlington, Everett, Framingham, Haverhill, Marlborough, Revere, Sharon and Stoneham, and Robby Robertson as an individual, and Greater Lowell Technical High School (collectively, Massachusetts Parties) and the Governor of Maine. The Northeast States for Coordinated Air Use Management (NESCAUM) and the Union of Concerned Scientists also filed comments regarding ISO-NE's demand response program.

DISCUSSION

Procedural Issues

8. The notices of intervention and the timely, unopposed motions to intervene serve to make the intervenors parties to the proceeding in which they moved to intervene. See 18 C.F.R. § 385.214 (2002). Given the early stage of this proceeding and the absence of undue delay or prejudice, we find good cause to grant the untimely, unopposed motions

---

[5] 68 Fed. Reg. 5014 (2003).

[6] 68 Fed. Reg. 6733 (2003).

[7] ISO-NE and NEPOOL subsequently filed the emergency suspension authority as a revision to Market Rule 1 under Docket No. ER03-550-000 (the Suspension Proposal), accepted by the Commission on April 22, 2003 in New England Power Pool, 103 FERC ¶ 61, 079 (2003).

to intervene in the proceedings in which they moved to intervene. Since the Massachusetts Parties, the Governor of Maine, NESCAUM and the Union of Concerned Scientists did not file motions to intervene, they are not parties to this proceeding, but we have nonetheless considered the materials submitted by them in reaching our ruling.

9. Under Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2)(2002), an answer may not be made to a request for rehearing absent authorization by the decisional authority. We will accept the answers to CT DPUC's motion for reopening and reconsideration, the answers to the requests for rehearing, and PG&E's answer to National Grid's protest to the January 21 compliance filing because they have provided material that has assisted us in considering this matter.

Analysis

10. We will grant rehearing and clarification in part and deny it in part, and accept the compliance filings in part and reject the compliance filings in part, as follows.

I. DCAs

11. **Section 205 question.** NU argues that the DCA filing should have been made under Section 205 of the Federal Power Act (FPA).[8] It argues that the Commission recognized the Section 205 requirement — that underlying formula calculations must be made available to those affected by formula rates — when in the December 20 order it stated that the Commission notes "that ISO-NE and NEPOOL must make an informational filing to allow us to approve (1) what areas are designated as DCAs, and (2) the CT proxy price for each DCA."[9] NU argues that the implementation of the DCA proposal should not take place until after the Commission has reviewed both the DCA and suspension proposals as Section 205 filings.[10]

---

[8]16 U.S.C. 824d (2003).

[9]December 20 Order at P 22.

[10]NU argues that the Commission should allow interested parties sufficient time to participate in the Suspension Proposal and maintains that full Section 205 protections be available to those parties. NSTAR and CMEEC have also filed comments regarding the Suspension Proposal. That proposal was accepted by the Commission in New England Power Pool and ISO New England, Inc., 103 FERC ¶ 61,079 (April 22, 2003) and we will therefore not address it here.

12. Commission response. Upon examination of ISO-NE's January 28 compliance filing, the Commission is persuaded that ISO-NE's designation of DCAs, for the future, should be a Section 205 filing. NU argues that the January 28 compliance filing "will dramatically impact the rates, terms and conditions of service in DCAs,"[11] and on that basis should be considered pursuant to Section 205. The January 28 compliance filing implements the mechanics of the DCA proposal by designating the DCAs and determining the precise CT proxy safe harbor bid for each DCA, and as such has the potential to have a meaningful impact on prices. In several cases, we have considered such implementation mechanisms to fall within the ambit of Section 205.[12] Thus, for the redesignations of DCAs that ISO-NE will conduct every year, we will require ISO-NE to file those redesignations under Section 205.

13. As to ISO-NE's January 28 filing, however, we will not grant NU's request for rehearing, which would, in effect, require ISO-NE to refile the January 28 filing before its DCA designations could be approved. Although ISO-NE made its January 28 filing as an informational filing, as described above, several parties filed protests, which we address below. Thus, market participants and others have been able to obtain Commission review of the January 28 filing, and we will not require ISO-NE to refile the same material, as to which the parties would then have to refile the same comments.

14. **Designation of DCAs.** NSTAR states in its request for rehearing that the commission errs by granting ISO-NE the discretion to determine which regions become a DCA and to set the CT proxy price, and argues for a "bright line" test so the determination of DCAs is transparent and constrained by objective criteria. TCPM questions the scope of the newly proposed DCAs, stating that ISO-NE did not clearly indicate that the proxy CT mechanism would not be limited to the most severely constrained areas in New England, pointing out that the ISO presented a proposal that would designate approximately 50 percent of the load in New England into DCAs.[13]

---

[11] NU request for rehearing at 15.

[12] Midwest Independent Transmission System Operator, Inc., 98 FERC ¶ 61,137 at 61,401 (2002) (Commission rules that proposed operating protocols "purport to govern fundamental duties of the Midwest ISO and the related obligations of Generators. It appears that the proposed Operating Protocols could significantly affect certain rates and services and as such are required to be filed pursuant to Section 205").

[13] TCPM also urges the Commission to not ignore the non-price barriers to entry in the DCAs, such as siting requirements, environmental constraints, and public opposition.

(continued...)

15. Commission response. The Commission has already approved the method by which ISO-NE designates DCAs and determines their geographic boundaries. In our September 20 Order we stated that:

> NEPOOL . . . will conduct an initial four-month stakeholder process during which members can participate in the designation of DCAs, and every year thereafter NEPOOL proposes to give notice of its DCA designations to its Markets Committee by September 30, and allow for two months of discussion and review before NEPOOL makes an informational filing with the Commission by November 1 of the upcoming year's designated DCAs.[14]

16. We reaffirmed our acceptance of ISO-NE's proposed process in the December 20 Order, noting that "ISO-NE and NEPOOL must make an informational filing to allow us to approve (1) what areas are designated as DCAs, and (2) the CT proxy price for each DCA,"[15] but not requiring a Section 205 filing (as discussed supra). Thus, to the extent that NSTAR is challenging our approval of the process by which ISO-NE designates DCAs and delineates their geographic boundaries, that challenge is now untimely. As to TCPM's rehearing request, TCPM is concerned primarily about harms that could occur to the New England market from the operation of the CT proxy mechanism; thus, since the CT proxy mechanism has now been superseded by the Devon proposal,[16] discussed infra, TCPM's concerns have become moot.

17. **DCAs as a Mechanism to Incent New Entry or Other Solutions to Congestion.** Several parties assert that DCAs, and the safe harbor pricing available within them, will not elicit new entry. NSTAR and Mass AG argue that setting DCA levels between \$80/MWH and \$90/MWH will not only fail to induce competitive bidding from suppliers but will also transfer wealth to suppliers without any benefit.

---

[13](...continued)
Further, TCPM argues that even if scarcity pricing eventually did induce new construction, for the two to four years needed for new capacity to go into service, existing generators would obtain excess profits.

[14]September 20 Order at P 43.

[15]December 20 Order at P 22.

[16]Devon Power LLC, 103 FERC ¶ 61,082 (2003) (Devon).

CTAG also argues that allowing price mark-ups without the threat of mitigation will result in the transfer of wealth from loads to generators. TCPM states the current and planned enhancements for generation and transmission will address the congestion issues, and the proxy CT proposal will not induce transmission owners to invest in upgrades to connect DCAs to neighboring uncongested areas because higher LMPs do not directly impact standalone transmission companies; rather, they will be borne by Load Serving Entities (LSEs) and end users.

18. Commission response. Those parties who argue that the DCA mechanism is flawed because it will not necessarily incent new entry are mis-stating its purpose. DCAs are "load pockets,"[17] regions that face particularly critical reliability problems during high demand periods, as well as heightened concerns about market power. Because of these characteristics, some generation assets in DCAs must receive sufficient income to remain available for reliability; and at the same time, ISO-NE must ensure that customers are protected from the exercise of market power. It is not the designation of such regions as a DCA that imposes these costs and difficulties on load; rather, it is the existence of the load pocket, whether designated a DCA or not. Thus, both the Commission's and ISO-NE's immediate concern is to protect customers from market power, while ensuring that generators required for reliability will remain economically viable (either through RMR contracts, or through a transparent market process), while at the same time the higher prices within DCAs should generate longer term solutions to the congestion in the load pocket, either through incenting entry or otherwise.

19. The DCA proposal, as originally put forth by NEPOOL and ISO-NE and as amended by the Commission in Devon, seeks to address all of these goals. While price signals will not necessarily guarantee generator entry, efficient entry of new generation and demand response requires prices that accurately reflect the value of additional supplies or conservation. Thus, the correct price signals sent through the DCA mechanism, when combined with appropriate scarcity pricing and/or a locational capacity mechanism, should ultimately bring about a decrease in congestion within the DCA.

20. As to protecting customers from market power, ISO-NE's original CT proxy mechanism established a safe harbor bid for units in DCAs designed to give seldom run,

[17]"A load pocket is an area of a system where demand for electricity exceeds the ability of the system by its transmission wires to import electricity into that area such that demand in the area must be met by generation located inside the area." KeySpan Energy Development Corporation v. New York Independent System Operator, 103 FERC ¶ 63,016 at P 46 fn. 17 (2003).

high cost units a greater opportunity to recover costs without concern for mitigation, but was also designed to prevent the exercise of market power by potentially mitigating bids that exceeded the price needed to attract efficient entry. The expectation was that this mechanism would permit these units to recover necessary costs through a market rather than through RMR contracts and would protect against the exercise of market power. We have fine-tuned this approach in Devon so as to allow seldom run, high cost units to recover their costs, but to provide even greater protection to customers from market power by applying tighter conduct and impact tests to other generators. Both the CT proxy mechanism and our revised Devon approach are methods that give greater emphasis to cost recovery through a market process rather than through contract payments not reflected in market prices.

21. That said, we recognize that concerns about market power cannot be dismissed. Our Devon revisions are designed as a short-term response to trade-offs between the need to support units needed for reliability, while protecting against the exercise of market power. Under Devon, generators in the DCA that normally serve load will be subject to the same mitigation as that applied to generators outside the DCA. Thus, the DCA designation only becomes relevant to mitigation when seldom run, high cost units are needed for reliability. Prices in DCAs may be higher than otherwise during those hours, but this would be offset by lower prices in other hours and by lower RMR contract costs. We view Devon as a transitional regime that is likely to be superseded, within a year. During the duration of the Devon regime, however, both ISO-NE's market monitor and market participants themselves will need to be vigilant to protect against market power, and we anticipate that they will be.

22. **Concentration of Generation Ownership.** NSTAR, TCPM and Mass AG argue that NEMA's underlying problem is a lack of ownership diversity which leads to non-competitive bidding conduct.[18] NSTAR and TCPM state that NEMA is a densely populated region subject to strict environmental regulation and without greenfield sites suitable for power facilities, and the sole available brownfield sites are owned by those suppliers that are already dominant in NEMA. TCPM, NU and Mass AG claim that this degree of market concentration gives a single participant sufficient market dominance to consistently set the market price at its location, which creates incentives to avoid, rather than develop, congestion solutions. NSTAR further submits that Northeastern Massachusetts (NEMA) may have a surplus of generation capacity for the summer of

[18]NSTAR asserts that three suppliers control 97 percent of NEMA's generation capacity. TCPM states that 92 percent of installed capacity in NEMA is owned and operated by two participants.

2003,[19] and asserts that ISO-NE and NEPOOL's analysis incorrectly assumes that congestion results from inadequate levels of generation, but that, in fact, it is bidding conduct that creates congestion.[20]

23. Commission response. The mitigation rules proposed by NEPOOL and ISO-NE and approved by the Commission effectively require all available generation in DCAs to bid competitively. Thus, the conduct and impact tests used as a basis for mitigation are directly focused on the kinds of bidding conduct that concern NSTAR.

24. Although possible barriers to entry may remain a general concern for New England parties (and state decisions on issues such as siting will have consequences for entry), efficient pricing is nonetheless a prerequisite for efficient entry. Further, the Commission disputes parties' argument that no new generation will enter DCAs. As NSTAR points out, Sithe has built its new Mystic units in NEMA, and as to Southwest Connecticut (SWCT), ISO-NE has stated that:

> On February 27, 2002, ISO-NE issued a Request for Proposals soliciting approximately 80 MW in Southwest Connecticut either through load response or supply resources. The Request for Proposals resulted in 83.6 MW of additional system resources of which over 69 MW were temporary peaking generating units.[21]

25. The New England market rules and mitigation should provide accurate price signals to support entry of generation, as well as transmission and demand response. Thus, we believe that new generation will be willing to enter New England's DCAs,

---

[19]NSTAR argues that, in designating DCAs, ISO-NE and NEPOOL relied on historical data and, moreover, fail to acknowledge capacity additions. NSTAR submits that, if the retirement of the New Boston facility as well as the addition of Mystic Units 8 and 9 are considered, on a prospective basis congestion is likely to be diminished in NEMA. NSTAR asserts that projections for summer 2003 include 5,400 MW of peak load, 3,900 MW of transfer capacity into NEMA, and close to 3,300 MW of generating capacity.

[20]NSTAR states that an ISO-sponsored report undertaken by Laurits R. Christensen Associates, Inc. confirms its contentions that (1) bidding behavior creates congestion and (2) eliminating market power will largely eliminate congestion.

[21]ISO-NE Annual Markets Report, issued 9/12/03, at 3.

assuming that it perceives the correct economic incentives, and the DCA program will provide those incentives. As to the argument regarding the high prices charged to load, now that the CT proxy price has been superseded by the Devon mechanism, load will see high prices in the hours when high cost, seldom run units are operating, but lower prices in all other hours, so that overall prices to load may be less than would have been the case under the CT proxy mechanism. Further, even if, under this program, load does pay higher prices initially before new entrants come on line, we believe that those higher prices within DCAs will serve to attract new entry, and will ultimately result in improved reliability and enhanced supply in New England's most congested areas.

26. **Safe Harbor Pricing Proposal.** The Massachusetts Parties and the Governor of Maine filed letters to voice opposition to the use of safe harbor pricing in DCAs.[22] These intervenors further argue that the financial impact of the pricing proposed in the DCA scheme is estimated to be more than five times greater than the prices under NE-SMD rules that went into effect on March 1. These intervenors contend that the expanded costs do not originate from congestion but rather from price signals and that these costs cannot be mitigated through Financial Transmission Right (FTR) auction revenues. These intervenors question the application of the safe-harbor pricing mechanism to any generator, including low-cost base-load units, and argue that the proposal should be tabled until further questions can be answered. These intervenors contend that if the DCA concept is intended to benefit new gas peaking units that may be developed, then the rule should be redrawn to benefit such plants when operational. They also argue that the rules put into place on March 1 (i.e., LMP pricing) should be given an opportunity to work. NSTAR argues that the proxy CT formula "perversely" results higher safe-harbor thresholds for DCAs that have fewer hours of congestion than for DCAs that have more hours of congestion, which in effect penalizes efficient transmission operation. And finally, CTAG argues that requiring the re-establishment of the DCA mechanism annually will not allow participants sufficient time to build a revenue stream to support the installation of a new plant, since insofar as the DCA mechanism terminates upon the entry of new generation, it will eliminate the incentive to locate there.

27. Commission Response. We note that in our recent Devon order, we have altered the CT proxy safe harbor mechanism previously proposed and approved for New England's DCAs. Previously, within DCAs, parties could bid up to the safe harbor price (the incremental operating cost for a hypothetical combustion turbine generator (CT proxy), plus annual fixed costs based on the number of hours that unit would be expected to operate), without the possibility that their bids would be mitigated. In Devon,

---

[22]Some of these intervenors, as well as NSTAR, state that 63 percent of NEPOOL members voted to oppose the DCA concept at a February 5, 2003 meeting in Boston.

however, we have eliminated the CT proxy safe harbor as it applied to all units. Within a DCA, a Peaking Unit Safe Harbor (PUSH) bid is developed for each seldom-operated peaking unit (a unit that only had a 10 percent or lower capacity factor during 2002). The PUSH level for each such unit will be the sum of that unit's variable costs and its fixed costs for 2002, divided by the number of MWH supplied in 2002). If the unit is already covered by an RMR contract, the fixed-cost portion of that is adjusted downward to reflect whatever fixed payments the unit is recovering under its RMR contract.

28. Within a DCA, in hours when no PUSH bid is accepted and such peaking units are not operating, all units may be subject to mitigation like units outside DCAs. During the hours when one or more PUSH bids are accepted within a DCA, the highest PUSH bid will serve as the clearing price for all bids. Although each unit within the DCA will receive this highest PUSH bid during these hours, this PUSH level will not, however, serve as a safe harbor for units not eligible for PUSH bidding; if a unit not eligible for PUSH bidding bids up to this high level and the market monitor finds that bid excessive, the market monitor may still mitigate the bid.

29. Thus, a completely different safe harbor regime has now been created, which will to a significant degree address the concerns of parties here. While all generators within DCAs will still have the opportunity to earn high prices during hours when one or more units submitting PUSH bids are operating, they will have no incentive to bid above their marginal costs, since (a) they will still receive the high clearing price in those hours, and (b) they will continue to face the possibility of mitigation. This should address the concerns of the Massachusetts Parties and the Governor of Maine regarding the financial impact of safe harbor pricing within DCAs: while prices to load will be relatively high during the hours that PUSH bids are accepted, we anticipate that relatively few such hours will occur each year. Further, with regard to the assertion that such costs cannot be hedged through FTR purchases, inter-zonal congestion can be hedged with FTRs. However, as to intra-zonal congestion, the safe harbor mechanism described above will protect against the exercise of market power. Finally, we disagree with CTAG's contention that the periodic re-establishment of DCAs will not allow participants to count on a revenue stream for a sufficient time to motivate new entry. In the short term, we believe that the PUSH mechanism will provide sufficient opportunity for new entrants to recover their costs. Over the long term, the implementation of locational ICAP and scarcity pricing after the expiration of the temporary PUSH mechanism should provide sufficient stimulus to keep such new units operating.

30. **Alternatives to DCAs and the CT proxy proposal.** NSTAR, NU, CT DPUC, Mass DTE, Mass AG, PSEG, and NE Suppliers raise challenges to and propose various alternatives to ISO-NE's original DCA and CT proxy proposal. Since, in Devon, we

have eliminated the CT proxy price mechanism in favor of the PUSH bid price mechanism, and thus altered significantly the way that DCAs will operate, these issues have become moot, and we will not, therefore, address them.

II. RMR Issues

31. **CT DPUC's request for reopening.** CT DPUC asks the Commission to reopen the record and reconsider its decision to allocate the costs of each RMR contract to load within the Reliability Region that the RMR generator serves. CT DPUC points to new information warranting this step, namely, (1) the fact that the Commission has been mediating a negotiation among Connecticut participants for appropriate rate treatment for certain Connecticut generators because their units are required to maintain reliability, and (2) an assessment of Connecticut generation performed by ISO-NE in November 2002 after which it concluded that all 7,000 MWs of Connecticut generation are required to ensure reliability in Connecticut. According to CT DPUC, "the entire New England grid benefits from RMR contracts that keep certain Connecticut generators operating,"[23] and thus, the costs of RMR contracts in Connecticut should be socialized throughout New England. In answer to CT DPUC's request, Central Maine and the Maine/RI Commissions state that CT DPUC has not met the standards for reopening this proceeding. ISO-NE points out that the "new evidence" which CT DPUC cites is based on a draft ISO-NE report, not a final document, and does not provide a basis for revisiting the issue of allocation of RMR costs. Mass DTE states that local socialization is the only way to send proper price signals, and urges the Commission to reject CT DPUC's request.

32. Commission response. The Commission will deny CT DPUC's request for reopening and reconsideration. The new information to which CT DPUC points does not justify revisiting a final Commission determination. Even if, when ISO-NE finalizes its draft reliability assessment, it concludes that all or much of Connecticut generation is required for reliability in Connecticut, this would not lead to the conclusion that this generation was required for reliability throughout New England.

33. **Socialization of RMR contracts.** NRG seeks rehearing, arguing that, if the Commission permits socialization of the costs of transmission upgrades for SWCT for the next five years, it should similarly permit socialization of the costs of RMR units for the next five years. NRG asserts that equivalent treatment is necessary to ensure that generation and transmission compete on equal terms to address reliability problems, to implement the Commission's policy that solutions to congestion should be developed

[23] CT DPUC request to reopen at 3.

through market signals rather than regulatory choices. NRG also states that the construction of transmission upgrades to address the problem of load pockets will probably be more expensive than maintenance or construction of generating facilities.

34. Commission Response. The Commission will deny NRG's request. The Commission is providing socialized treatment for transmission upgrades for SWCT, solely for the next five years, in part as an incentive. It is hoped that the opening of this five-year window will motivate parties in SWCT to overcome the obstacles that have heretofore held them back from addressing their transmission constraints. RMR contracts, by contrast, are not an incentive program. To the contrary, the Commission intends RMR contracts for old, inefficient generators to be, at best, a stopgap measure until newer and more efficient generation is constructed. Put another way, the Commission has granted socialized treatment for transmission upgrades, for a limited time only, because it wishes to incent construction of additional transmission upgrades. But we do not wish to incent construction of additional generation that will require RMR contracts (cost-based or otherwise) rather than being efficient enough to recover their costs while charging market-based rates.

35. **Parameters for RMR contracts**. NSTAR, in its request for rehearing, states that the Commission has failed to establish appropriate parameters for RMR contracts. NSTAR argues that the Commission should have allowed the pool to exercise complete control over an RMR generator's facility, including its bidding conduct; that the Commission should have restricted the availability of RMR contracts to the minimum number of MWs needed for reliability purposes; that RMR generators should not be allowed to swing between market-based rates and cost-of-service rates; that RMR agreements should be ineffective until they are actually approved by the Commission; and that NEPOOL participants should be allowed to review ISO-NE's classifications of resources as being appropriate recipients of an RMR contract.

36. Commission response. In Devon, the Commission has provided additional guidance as to the use of RMR contracts within ISO-NE. We stated that "extensive use of RMR contracts undermines effective market performance . . . . Therefore, we believe that ISO-NE, rather than focusing on and using stand-alone RMR agreements, should incorporate the effect of those agreements into a market-type mechanism."[24] We further noted that "RMR contracts should be a last resort."[25]

[24]Devon at P 29.

[25]Id. at P 31.

37. DCAs in New England were identified to target a specific New England reliability problem that ultimately will be addressed by a locational capacity requirement and scarcity pricing. Transmission constraints defining DCAs sometimes require the maintenance and operation of very high cost, seldom run units within the DCAs to maintain reliability. ISO-NE was concerned that, absent some modification to its mitigation rules, these units might be forced to shut down since they may not operate over enough hours at a high enough price to remain economically viable. Related to this concern is the ability of scarcity prices to attract new, more efficient entry into these regions.

38. To respond to this concern, ISO-NE initially proposed that generators in DCAs have a more generous safe harbor bidding range with an upper limit established by a CT proxy. ISO-NE expected that its CT proxy mechanism would eliminate the need for most RMR contracts previously used to compensate many high cost, seldom run units, and give most generators an opportunity to recover costs in transparent spot markets. At the same time, the CT proxy would protect against the exercise of market power by setting a safe harbor bid at a level that would incent efficient entry.

39. Since authorizing the CT proxy mechanism for three designated DCAs, a number of suppliers in DCAs have requested cost-of-service RMR contracts. They complain that even at a CT proxy price, they operate for too few hours to remain economic. Other parties complain that the CT proxy mechanism permits higher prices when they are not warranted. As a result, the Commission has reviewed its decision on the CT proxy mechanism and in Devon directed that New England modify its CT proxy plan to better meet its goals of permitting high cost, seldom run units to recover costs through the market without resorting to RMR contracts and protecting customers against the exercise of market power. As discussed above, the modified mechanism gives only the highest cost units in DCAs that have a capacity factor of 10 percent or less the ability to bid at high levels without mitigation. For these units only, New England will develop a higher safe harbor bid that permits full recovery of all variable and fixed going forward costs over the few hours of expected operation. This revised mitigation plan serves only as an interim measure until New England implements is locational capacity requirement. The mechanism allows for higher prices, but only when the highest cost units are needed to serve the market. In all other periods, market clearing prices in DCAs should be less than the estimated CT proxies under the original NE-SMD proposal.

40. We anticipate that the change that we have ordered for ISO-NE's DCAs (from the use of the CT proxy mechanism to the use of the PUSH bid mechanism) should make RMR contracts less necessary, and less frequent. Within the new parameters provided in Devon, each application for an RMR contract should be evaluated on its own merits.

41. Lest any party wonder whether RMR contracts into which ISO-NE and other generators have already entered are vitiated by either Devon or this order, this is not the case. We note, however, that in Devon we stressed that RMR contracts should be as brief in duration as possible,[26] and it is our understanding that ISO-NE generally does not enter into an RMR contract for more than one year's duration. We encourage ISO-NE only to enter into RMR contracts for the minimum period it believes that the RMR unit will be required.

III. Market Monitoring and Mitigation

42. In its Appendix A to Market Rule 1, ISO-NE lays out its approach for monitoring and mitigating market power. This approach identifies resources potentially exercising market power by comparing their current energy supply offers with a proxy for what the resource would bid if it had no market power. When the supply offer significantly exceeds the proxy B referred to as the reference price B an investigation is triggered that may result in mitigation. The Commission accepted ISO-NE's mitigation proposal for periods when transmission constraints cause a unit to be dispatched above the level it would have been dispatched absent the constraint.

43. Appendix A also states that the ISO, in consultation with its Independent Market Advisor, will monitor the market for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified for the imposition of Mitigation Measures by the ISO. If the ISO, in consultation with the Independent Market Advisor, identifies any such conduct, it may make a filing under Section 205 with the Commission requesting authorization to apply appropriate Mitigation Measures. Any such filing must identify the particular conduct that warrants mitigation, propose a specific mitigation measure for the conduct, and present the ISO’s justification for imposing that mitigation measure.

44. In their request for clarification or rehearing, the Maine/RI Commissions request the Commission to clarify that it did not prohibit ISO-NE from continuing to use its reference bid and price screens to monitor bidding behavior in non-transmission constrained areas, and provide the results of ISO-NE's market monitoring obligation to the Commission and to state regulators. In its request for rehearing, NSTAR protests that

[26]"In the December 20 Order the Commission added that it expects ISO-NE to enter into RMR agreements with only those units that are needed for reliability and that the Commission expects that the agreements will be in effect only for the period during which the units are needed for reliability," Devon at P 30, citing the December 20 Order at P 33.

the Commission has allowed ISO-NE excessive discretion to consult with generators prior to imposing mitigation. NSTAR asserts that when a generator exhibits bidding behavior that exceeds the threshold test and materially impacts the clearing price, mitigation must be imposed regardless of any explanation that a generator may provide. NSTAR additionally asserts that the process inappropriately relies solely on the judgement of ISO-NE that a generator should or should not be mitigated, and thus lacks transparency. NSTAR states that the Commission has rejected similar proposals for the New York Independent System Operator.[27]

45. Commission Response. We will grant the clarification requested by Maine/RI Commissions, and state that we did not prohibit ISO-NE from continuing to use its reference bid and price screens to monitor bidding behavior in non-transmission constrained areas. We also require ISO-NE to provide the results of ISO-NE's market monitoring obligation to the Commission and to state regulators. We did not intend that the Market Monitor be restricted in the performance of its obligation.

46. With regard to the issue raised by NSTAR, we find that ISO-NE does not have excessive discretion in applying the mitigation measures in Appendix A. We disagree with NSTAR's assertion that there can be no circumstance under which a resource's supply offers, increment offers, demand bids, decrement bids or offers for Installed Capability (ICAP), among others, can trigger mitigation thresholds and be legitimate. NSTAR cites to NYISO to support its assertion that the Commission limits discretion in applying mitigation, but the findings in that order are distinguishable from the situation here. In NYISO, the Commission rejected the proposal to allow NYISO to impose certain conditions upon bidders because:

> The ISO has not established specific thresholds or bright line tests that would trigger the conclusions that market power has been exercised. The plan states that the ISO will choose one or more of the mitigation measures to the minimum extent necessary to mitigate price effects, but what constitutes this minimum is left to the discretion of the ISO. Moreover, the proposal includes no provision for an affected participant to appeal the ISO's decision to the Commission.[28]

---

[27]New York Independent System Operator, 89 FERC ¶ 61,196 at 61,605 (1999) (NYISO).

[28]NYISO, 89 FERC at 61,605.

47. We find that ISO-NE has established specific thresholds and bright line test sufficient to trigger the conclusion that market power has been exercised.[29] We also note that while Market Rule 1, Appendix A states that ISO-NE will "request an explanation of the conduct" whenever practical before imposing mitigation measures, this is not equivalent to a consultative or negotiated process. Further, consistent with the Commission's order in NYISO, ISO-NE has included an Alternative Dispute Resolution (ADR) process for review of any ISO-imposed mitigation measure.

48. With regard to transparency, in addition to an annual report, Section 11.2.1 of Appendix A provides for monthly reports of the market's performance and Section 11.2.2 provides for a quarterly report for regulators. We would expect to see all instances of the imposition of mitigation listed in the monthly, quarterly and annual reports. We do not require complete transparency of ISO-NE's mitigation, as some of the information is competitively and commercially sensitive. We find ISO-NE's statement that these reports will be subject to confidentiality protections to be consistent with the NEPOOL Information Policy, which prevents the inappropriate dissemination of competitively sensitive data, and an acceptable limitation on transparency.

IV. Allocation of Costs for Transmission Upgrades

49. In the December 20 Order, the Commission denied the requests of Connecticut parties to delay the implementation of LMP in Connecticut pending a resolution to transmission constraints in SWCT. We found that "[d]elaying LMP would delay the benefits to New England of sending more accurate price signals about the costs of delivering electricity to the various locations in that area" and that "more accurate price signals will encourage more efficient supply and demand decisions in both the short and long run."[30]

50. We also found, however:

> As a matter of equity, it would be reasonable to adopt measures that could moderate the financial impact of LMP on Connecticut consumers without blunting LMP price signals. One measure would be to reduce congestion by building a defined set of transmission upgrades into Southwest

[29] NEPOOL FERC Electric Rate Schedule No. 7, Market Rule 1, Appendix A – Market Monitoring, Reporting and Market Power Mitigation.

[30] December 20 Order at P 35.

> Connecticut, identified at the start of the implementation of LMP, and to assign a portion of the upgrade costs to other New England customers.[31]

51. We noted that we had permitted a similar mechanism for the customers in Northeastern Massachusetts (NEMA), and permitted socialization, for an interim period, of transmission upgrades into NEMA so as to moderate the price impacts of LMP to NEMA customers.[32] Thus, we stated:

> To aid in the transition to LMP, we encourage ISO-NE to work with New England market participants to identify and construct a defined set of transmission upgrades into Southwest Connecticut, and we commit to allowing the costs of such upgrades that are placed in service within 5 years from the date of this order to be spread among customers throughout New England.[33]

52. We stated that "[t]his rate treatment will also apply to those upgrades that are already planned or under construction as of the date of this order, such as the transmission upgrades in ISO-NE's 2002 Transmission Expansion Plan to address problems in Southwest Connecticut, as to which Phase 1 is planned to be completed in 2004 and Phase 2 is planned to be completed in 2006."[34] We further noted that the socialization of transmission upgrades in this fashion would be consistent with our further ruling in the December 20 order that the costs of demand response will also be spread system-wide.

53. Several parties seek rehearing of this ruling, arguing that this treatment may not be justified for multiple reasons, and that the Commission has departed from its policy of recovering costs from those who caused the costs to be incurred, and that the Commission's decision here grants benefits to SWCT customers at the expense of customers throughout the rest of New England.

54. With regard to our ruling that NEPOOL must develop a cost allocation methodology for transmission upgrades other than those for SWCT, the Maine/RI Commissions and Mass DTE ask us to clarify that we are not altering our long-held

---

[31] Id. at P 36.

[32] Id. at P 36 n.14.

[33] Id. at P 36.

[34] Id. at P 36 n.15.

position that transmission upgrades should be paid for by those parties who benefit, and that we should make clear that we would reject a mechanism that automatically socializes transmission upgrade costs, even if such a proposal should emerge from a NEPOOL stakeholder process.

55. Commission response. On May 20, 2003, the Commission held a technical conference in Boston, Massachusetts, to discuss with states and market participants reasonable timetables for addressing wholesale market design issues discussed in the Commission's SMD White Paper and ways to tailor the final rule to benefit customers. During the course of that conference, the Commission was informed that ISO-NE is evaluating new proposals for an appropriate cost allocation mechanism for transmission upgrades that reflect a regional policy decision based on a mutually acceptable sharing of costs among states. The Commission was informed that the Regional State Committee will try to achieve consensus among the states on a cost allocation plan. If they can reach such an agreement, this plan would be filed by ISO-NE. If not, then another cost allocation plan would be filed by ISO-NE based on NEPOOL decisions. In either case, a plan is expected to be filed with the Commission before October 2003.

56. In light of this development, we will not rule at this time on the pending requests for rehearing and clarification regarding any issues as to the allocation of costs for transmission upgrades, both in SWCT and elsewhere in New England. We recognize that New England's states and market participants are in the best position to develop solutions to the problems of cost allocation that will be acceptable to all parties, and we urge the parties to work toward developing consensus on this question. We anticipate that the regional process described above will bear fruit relatively shortly, and for this reason, we will hold in abeyance all of the pending requests for rehearing on these cost allocation issues, and rule on them in a subsequent order.

V. Demand Response Issues

57. In their January 21 compliance filing, ISO-NE and NEPOOL filed changes to Market Rule 1 with regard to demand response issues, as follows.

58. In response to the Commission's direction in paragraph 48 of the December 20 Order, that "[a]s to allocating the costs associated with the Real-Time Demand Response Program, system-wide, we will allow such allocation as an initial matter, in order to encourage the development of demand response programs," NEPOOL and ISO-NE changed Section 1.4 and 2.3 of Appendix E. The revisions allocate the costs of all of the Load Response Programs system-wide instead of on a zonal basis. Although the December 20 Order only specified that the allocation of costs for the Real-Time Demand Response Program be changed, ISO-NE expressed concern that "different cost allocation

methodologies for different Load Response Programs would be exceedingly burdensome on its operations."[35] The NEPOOL Participants Committee approved this recommendation.

59. In paragraph 45 of the December 20 Order, the Commission directed the bid ceiling for the Day-Ahead Demand Response Program be raised from $500/MWH to $1,000/MWH. The compliance filing changed Section 2.3 of Appendix E to reflect this directive.

60. In paragraph 47 of the December 20 Order, the Commission directed NEPOOL "to make a filing revising its demand response programs to reflect the results of the NEDRI process." The New England Demand Response Initiative (NEDRI) process has debated changes to the ISO-NE's Load Response programs. In response to the Commission's directive, ISO-NE and NEPOOL focused on the preliminary recommendations that were contained in early draft reports of a NEDRI report on Regional Demand Response.[36] The specific NEDRI-related changes contained in the compliance filing are in Sections 1.1, 1.3, 3.3 and 3.5 of Appendix E to Market Rule 1. In Section 1.1, the annual fee assessed on non-Participants who take part in the Load Response Program has been reduced from $5,000 per year to $500 per year. In Section 1.3, the duration of the program has been increased to three years until February 28, 2006. In Section 3.3, the minimum guaranteed payment to participants in the 30-minute Real-Time Demand Response Program has been changed from $150/MWH to $500/MWH, and in Section 3.5 the minimum guaranteed payment to participants in the 2-hour Real-Time Demand Response Program has been changed from $100/MWH to $350 MWH.

61. NEPOOL filed a motion for clarification or request for rehearing of the December 20 order. According to NEPOOL, the Commission did not "clearly set forth the scope of the NEDRI revisions that NEPOOL must submit,"[37] and seeks clarification as to "whether the [Commission] requires NEPOOL to submit more than these preliminary recommendations, and specifically to include other provisions that are not related to the Load Response Program or any or all proposals that ultimately may arise

[35]January 21 compliance filing at 8 fn. 8.

[36]The final version of the NEDRI report and recommendations was not complete until January 15, 2003, which was after the January 10, 2003 NEPOOL Participants Committee meeting.

[37]NEPOOL request for rehearing at 2.

from the NEDRI process, whenever issued."[38] NEPOOL requests rehearing if the Commission intended to require NEPOOL to submit NEDRI-based revisions to the Load Response Program beyond those recommendations adopted in the January 21 compliance filing. NEPOOL also seeks clarification that NEPOOL's adoption of NEDRI's extension of the sunset date for the Load Response Program does not preclude NEPOOL and ISO-NE from refining the program prior to this date.

62. Two commenters addressed the system-wide allocation of all costs of the real-time demand response program. Central Maine seeks rehearing of the December 20 Order's requirement to socialize demand response costs, on the basis that socialization violates cost causation principles. According to Central Maine, real-time demand response programs that are operated on a zonal basis will benefit only customers within that load zone. Hence, socialization will lead to "perverse" results, like participation of end users who do not provide value to the program. The Maine/RI Commissions seek clarification that the socialization of costs of such programs is for a limited period and asks the Commission to specify an end date for this rate treatment.

63. In its comments on NEPOOL and ISO-NE's January 21 compliance report, NECPUC provides a copy of the final NEDRI report, issued on January 15, 2003, and asks the Commission to clarify that all parties are permitted to comment not solely on the specific revisions to the Load Response Program included in NEPOOL's compliance filing, but on the entirety of the report. NECPUC does not take any position on the recommendations contained in the report. NESCAUM urges that the Commission adopt as a package all of the recommendations developed by NEDRI with respect to the ISO-NE proposed demand response programs for summer 2003, and included in NEDRI's January 15 report. In particular, NESCAUM requests that the recommendations related to environmental compliance and reporting be included in NEPOOL's compliance with the December 20 Order. NESCAUM supports a requirement that customers deploying on-site generation affirm their compliance with applicable environmental permitting requirements, or provide a written waiver from state air regulators indicating that a permit is not required before they are allowed to participate in economic demand response programs. In addition, NESCAUM also supports NEDRI's recommendation that ISO-NE collect and share data with state air regulators on the actual operation of on-site generators in various demand response programs so that regulators can assess environmental impacts. The Union of Concerned Scientists supports NESCAUM's position.

[38] NEPOOL request for rehearing at 9.

64. Commission response. The Commission rejects NECPUC's request for a clarification that all parties are permitted to comment on the entirety of the NEDRI report. The directive in the December 20 Order was for NEPOOL to reflect the results of the NEDRI process in its compliance filing. Hence, the extent to which NEPOOL reflected these results was already subject to comment in this proceeding.

65. The Commission also rejects as both premature and outside of the Commission's jurisdiction NESCAUM's request that the recommendations related to environmental compliance and reporting be adopted. Environmental compliance is primarily the role of state air quality regulators. While other independent system operators (ISOs), particularly NYISO, have incorporated restrictions on the operation of emergency generators in their demand response programs, the adoption of these restrictions did not require Commission direction or approval. Similarly, it is beyond the Commission's jurisdiction to direct ISO-NE to collect and share data with state air quality regulators.

66. In response to the rehearing requests of Central Maine and the Maine/RI Commissions, we will deny the requests and provide clarification. As we stated in a recent order on the allocation of demand response program costs to network load, "the primary benefits of demand response programs are improved market operation and reliability, and the primary beneficiary of those is load."[39] We believe as an initial matter, and to provide impetus for these types of programs, a system-wide allocation program is appropriate. We also recognize, however, that some demand response programs may have a more targeted value to some loads than to others. In this regard, we grant the Maine/RI Commissions' request for clarification and direct the system-wide allocation continue until the extended sunset date included in the January 21 compliance filing, February 28, 2006. We will expect ISO-NE and New England parties to use the experience and insights gained from three summer capability periods of demand response operation and evaluation, and the transmission cost allocation discussions that will occur between now and then to develop a new demand response cost allocation proposal for the period after February 28, 2006, to be submitted to the Commission by December 1, 2005.

67. The intent of the December 20 Order was to require NEPOOL to reflect the results of the NEDRI process. The Commission's direction was not open-ended. The results that NEPOOL was directed to reflect are the recommendations specific to ISO-NE contained in the Regional Demand Response Programs chapter of the NEDRI Final

---

[39] ISO New England, Inc., 102 FERC ¶ 61,202 at P 17 (2003).

Report.[40] Within this limited time, NEPOOL was only able to review and consider a preliminary version of these recommendations. In response to NEPOOL's Motion for Clarification, the Commission accepts the revisions contained in the January 21 compliance filing as responsive to the December 20 Order, and will not require a continuing obligation for NEPOOL to be subject to any future demand response recommendations for ISO-NE beyond those included in NEDRI's Final Report.

68. NEPOOL and ISO-NE are to be commended for incorporating multiple NEDRI recommendations in its compliance filing. We accept all of the portions of the January 21 compliance filing that deal with demand response. These changes should foster greater participation in the programs and create additional demand response in the New England market. Nevertheless, NEPOOL only submitted the changes arising from NEDRI's preliminary recommendations that "it concluded were required."[41] The Commission has identified several additional recommendations in the preliminary report that were not considered by NEPOOL during their deliberations.[42] These additional NEDRI recommendations need to be considered by NEPOOL because they represent the results of an extensive, well-informed and expansive stakeholder process. Recommended revisions to ISO-NE programs include (1) inclusion of more flexible bidding processes by removing the requirement that no bid can be smaller than one MW, (2) implementation of an effective, location-based ICAP resource credit, and (3) development of an "economic, price-driven" day-ahead market demand response program by 2004. Additionally, NEDRI’s January 15 final report included two new recommendations that were not included in the preliminary recommendations: (1) allowing fixed bids each month or capability period in the Day-Ahead Demand Response program instead of the daily bidding requirement, and (2) permitting demand resources to enroll in both the Day-Ahead and Real-Time Demand Response programs. The Commission believes the above recommendations have value and directs NEPOOL to consider them for implementation in or before the summer of 2004. The Commission directs NEPOOL to submit a compliance filing no later than December 31, 2003 indicating whether NEPOOL has approved these recommendations and how the current programs will be revised, if necessary, for implementation by March 31, 2004.

---

[40]New England Demand Response Initiative, Regional Demand Response Programs (January 15, 2003).

[41]NEPOOL request for rehearing at 9.

[42]New England Demand Response Initiative, Price-Responsive Load Programs, November 14, 2002.

69. In the meantime, NEDRI offered two additional recommendations that are worth implementing now without formal NEPOOL approval. First, ISO-NE is directed to prepare and submit an "independent" in-depth process and impact evaluation and market assessment of its 2003 demand response programs by December 31, 2003, and to provide a similar evaluation by the end of each calendar year until and including December 31, 2005. Second, NEPOOL and ISO-NE must expand the role of the ISO-NE Demand Response Working Group through regularly scheduled meetings and broader participation.

70. In response to NEPOOL's request for clarification, NEPOOL's adoption of NEDRI's extension of the sunset date for the Load Response Program does not preclude NEPOOL and ISO-NE from refining the program prior to the new sunset date.

VI. ICAP

71. National Grid requests rehearing on the development of a locational ICAP mechanism required by the September 20 and December 20 Orders. National Grid believes that the Commission should reverse the requirement that NEPOOL consider adoption of a locational ICAP mechanism or, at a minimum, clarify that this requirement does not preclude the development of a regional deliverability requirement. National Grid observes that the Commission's decision in the September 20 Order was premised in part on the belief that NEPOOL and NYISO would be joining to form a Regional Transmission Organization (RTO). National Grid also states that a deliverability requirement consistent with that of PJM is more in line with the objectives of the resource adequacy discussion in the Commission's standard market design notice of proposed rulemaking[43] than the locational mechanism for ICAP in use in NYISO.

72. National Grid distinguishes between a locational requirement and a deliverability requirement. National Grid argues that, under a locational requirement pursuant to which the ICAP resource and load must be in the same load pocket, there would be no incentive to incorporate the load pocket into the regional market. A locational requirement would thus create disincentives to the enlargement and interconnection of markets because a locational requirement will increase the insularity of load pockets by restricting the import of capacity and weakening incentives for the development of transmission capacity. Thus, National Grid argues, the use of a locational ICAP

[43] Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 100 FERC ¶ 61,138 (2002) (SMD NOPR).

requirement in NEPOOL may interfere with the Commission's objectives for the elimination of geographically limited markets contained in the SMD NOPR.[44]

73. Commission Response. While National Grid correctly observed that we had in mind a possible New England/New York RTO in the September 20 Order, we noted in the December 20 Order that the boards of ISO-NE and NYISO had by then withdrawn their request to form a single Northeastern RTO.[45] The Commission's concern is that the location of an ICAP resource and the location of the load, as well as the transmission system between the two, should be taken into account in determining whether a resource can qualify to supply capacity to a given load. This is currently a major shortcoming of the NEPOOL market that is affecting energy prices within constrained areas. It also affects the coordination of external capacity resources with the neighboring market in New York, as evidenced by the issues in the implementation of Unforced Capacity Deliverability Rights (UDRs) in NYISO,[46] thereby perpetuating a major seam between the two markets. We grant National Grid's requested clarification that the Commission did not intend to preclude any particular mechanism that will achieve these goal and the goals contained in the SMD NOPR.

74. The Commission initially took the position that, rather than requiring NEPOOL to develop a locational ICAP mechanism only to have it replaced by another in order to comply with a final SMD rulemaking, it would be more prudent to wait. This was the Commission's main reason for not requiring NEPOOL to develop a resource adequacy mechanism immediately and instead requiring that NEPOOL develop a locational mechanism together with the other northeastern ISOs within the context of the development of a Northeastern RTO in accordance with a final SMD rulemaking.[47] However, we are now observing that the issues of ICAP deliverability and generator compensation are becoming more critical as NE-SMD moves through implementation,

[44]In the compliance filing made by ISO-NE on March 20, 2003 in ER02-2330-011 the ISO states that it anticipates implementing locational ICAP in 2004 and that it has discussed a schedule with the NEPOOL Market Committee and will make a filing with the Commission by the end of 2003. See March 20 compliance filing at 12.

[45]December 20 Order at P 102.

[46]See New York State Electric & Gas Corporation, 101 FERC ¶ 61,037 at P 13-14 (2002).

[47]September 20 Order at P 101.

given the proliferation of RMR contracts,[48] and we are now of the view that the NEPOOL market may be better served by having a resource adequacy mechanism in place sooner. As NE-SMD proceeds through implementation, it appears that there is a significant need for location-specific capacity payments and a widespread cross section of participants continue to call for a location-specific mechanism.

75. As a result, in Devon we directed ISO-NE to develop and implement a mechanism that implements location or deliverability requirements in the ICAP market. In Devon, we ordered that this mechanism is to be filed no later than March 1, 2004 for implementation no later than June 1, 2004 (coinciding with the start of the capability year). We additionally reiterate that it is the Commission's intent that this mechanism be developed in accordance with previous discussions, be compatible with neighboring control areas in order to eliminate continuing seams issues. In developing this mechanism, ISO-NE and NEPOOL should continue to include progress in the stakeholder process in its ongoing compliance filings and status reports regarding NE-SMD.

VII. Nodal/Zonal Issues

76. NE-SMD instituted prices based on LMP which are initially nodal for supply, but zonal for loads.[49] Zonal prices will be calculated for the Day-Ahead and Real-Time markets using a load-weighted average of the LMPs at the nodes within each Load Zone. NEPOOL and ISO-NE state that they have adopted zonal rather than nodal pricing for load because of features unique to New England.[50] In the December 20 Order, the

---

[48]See Devon, supra, and PPL Wallingford Energy LLC, PPL Wallingford Energy, LLC,103 FERC ¶ 61,185 (2003).

[49]ISO-NE states that its software will support nodal pricing for load once the necessary procedures, protocols, hardware and software for such pricing are in place in New England. ISO-NE's transmittal letter in July 13, 2002 filing, Docket No. ER02-2330-000, at 2.

[50]NEPOOL and ISO-NE state that nodal pricing cannot be used for load until improvements are made to the metering and reporting infrastructure in New England. Currently, customer load is mapped to each pricing zone and then allocated to Load Assets, which are the various suppliers serving load within that zone. To implement nodal pricing, the transmission and distribution companies that serve as meter readers in New England will have to remap customer load to separate nodes, rather than to separate suppliers. ISO-NE and NEPOOL anticipate that this process will take approximately 18

(continued...)

Commission directed ISO-NE and NEPOOL to offer nodal pricing to customers where it is technologically feasible to do so.

77. ISO-NE has indicated that there are practical, technical and logical impediments to allowing nodal pricing and zonal pricing simultaneously in the same geographic subregion. Accordingly, technical feasibility has been interpreted by ISO-NE to mean implementation of nodal pricing as soon as possible on a zone-by-zone basis, but not within an existing zone. ISO-NE seeks clarification that the December 20 Order does not require implementation on a piecemeal basis within a zone.

78. NU seeks rehearing regarding the potential for unintended consequences of offering nodal pricing to some customers before the infrastructure is developed that would support nodal pricing for all New England customers. NU alleges that allowing nodal pricing within a framework of zonal pricing could incent load at low price nodes to seek competitive suppliers, leaving those who stay with higher average zonal prices. For this reason, NU supports the Commission's decision regarding a minimum 18-month implementation period and requests reconsideration of the Commission's directive that ISO-NE and NEPOOL offer nodal pricing to customers in advance of that period. As a corollary, NU requests that any offer of nodal pricing to load be preceded by a minimum of one year's notice, so that existing contracts not be adversely affected and the market has the opportunity to prepare for the resultant cost shifts.

79. Commission Response. We will grant the clarification sought by ISO-NE and deny that sought by NU. We find a potential for adverse market consequences present when nodal pricing is offered within a zone to only a subset of the customers, and we will therefore not require piecemeal implementation of nodal pricing. We find, however, that NU has submitted only an assertion that such consequences could result from a move to nodal pricing on a zone by zone basis. NU's request for a one-year notice period before transition to nodal pricing is unnecessary. Nodal pricing was discussed in the July 15, 2002 filing of the ISO-NE SMD Proposal as being a key feature of the ISO-NE SMD market design which was missing in the original startup of ISO-NE SMD, but to be implemented as soon as possible. NU may consider itself on notice of the transition to nodal pricing now.[51]

---

[50](...continued)
months starting from the implementation of NE-SMD on March 1, 2003. Until then, they urge the use of zonal pricing for load.

[51]NSTAR questions the approval of subdividing Massachusetts into three pricing
(continued...)

VII. Allocation of ARRs

80. In response to our September 20 Order, ISO-NE and NEPOOL revised their proposal for allocating Auction Revenue Rights (ARRs) so as to allocate ARRs to Congestion Paying LSEs. The term "Congestion Paying LSE" is defined as:

> A Participant or Non-Participant that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service or Long-Term Point-to-Point Transmission Service under the NEPOOL Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with NEPOOL System Rules, in which case the Congestion Paying LSE shall be the Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the NEPOOL System Rules.[52]

81. In the December 20 order, we accepted the proposal of ISO-NE and NEPOOL to allocate ARRs to Congestion Paying LSEs because we concluded that the proposal would allow load to receive the benefits of ARRs. We reasoned that one type of Congestion Paying LSE is an entity that is a Transmission Customer that pays an embedded cost charge for its Transmission Service, and that is responsible for paying Congestion Costs. It was our understanding that each entity serving energy to load would pay congestion costs, either by virtue of purchasing energy in ISO-NE's spot market or by paying transmission congestion charges for transmission service to move bilaterally-contracted energy to load. As a result, every Transmission Customer that pays an embedded cost charge for its Transmission Service and that serves energy to load is a Congestion Paying LSE, and would be eligible to receive ARRs. We reasoned that the other type of Congestion Paying LSE is an entity in a retail-choice state that takes over, from a Transmission Customers that pays for an embedded cost charge for its

[51](...continued)
zones. NSTAR raised this issue in its request for rehearing of the September 20 Order, and the Commission addressed it in the December 20 Order at P 85. We will not, therefore, address this issue again.

[52]Transmittal letter of the October 21, 2002 NEPOOL Report on Compliance at 6. This definition is also now found in Market Rule 1 of the NEPOOL Standard Market Design, Section 1 - Market Operations, Substitute Original Sheet No. 5.

Transmission Service, the responsibility to supply energy to the load formerly served by the Transmission Customer. We concluded that competition among retail service providers would cause the benefits of the ARRs to be flowed through to retail loads.

82. We directed ISO-NE and NEPOOL to file a statement explaining whether our understanding is correct. On January 21, 2003, ISO-NE and NEPOOL made a compliance filing which stated, among other things, that our understanding of the term "Congestion Paying LSE" appears to be correct with one clarification. That is, that internal bilateral contracts in NEPOOL are financial in nature and that they simply transfer the obligation to serve a load as reflected in ISO-NE's settlement system.

83. National Grid argues in its request for rehearing that the Commission should reject the compliance filing's allocation of ARRs to Congestion Paying LSEs because this allocation does not ensure that those who directly pay embedded cost transmission charges (or the retail loads that ultimately bear the embedded costs) receive the benefits of ARRs. National Grid states that transmission customers that pay transmission embedded costs but have entered into an agreement to transfer load responsibility (such as to a retail service provider) may be denied an allocation of ARRs. Moreover, National Grid disagrees with the conclusion in the December 20 order that competition among retail service providers would induce retail service providers to flow the benefits of ARRs to retail loads, for two reasons. First, many energy suppliers that would be allocated ARRs have contracted with load under long-term fixed-price agreements executed before the concept of ARRs was introduced in New England. Second, many retail markets are not yet sufficiently competitive to force retail service providers to flow the benefits of ARRs through to their retail loads.

84. Commission Response: We will deny National Grid's request to reject the compliance filing's allocation of ARRs to Congestion Paying LSEs, and we accept the portion of the January 21 compliance filing dealing with the allocation of ARRs. As we noted in the December 20 order, while some entities that do not directly pay embedded cost transmission charges would be allocated ARRs, the retail loads served by these entities ultimately bear the embedded costs of the transmission system, and we expect that these retail loads will receive the benefits of the ARRs. While some of the retail loads may be served under contracts with fixed prices that will not initially reflect the benefits of ARRs, this situation is temporary. As National Grid notes, when these contracts expire, their provisions can be renegotiated to reflect the benefits of ARRs. Moreover, as ISO-NE and NEPOOL explained in their original proposal, allocating ARRs to retail service providers ensures that ARRs follow load, and thus increases the ability of new entrants to compete with traditional utilities for the right to serve retail load.

IX. Operating Reserves Allocator

85. In the December 20 Order, the Commission directed ISO-NE and NEPOOL to (1) clarify the difference between Real Time Load Obligation Deviation and Real Time Adjusted Load Obligation Deviation, beyond that offered in Section 3.2.1 of the tariff; (2) distinguish between internal bilateral transactions for load and internal bilateral transactions for energy; and (3) elaborate on the flexibility Real Time Load Obligation Deviation affords generators selling to marketers. In the January 21 compliance filing, ISO-NE and NEPOOL reiterated their view that Real Time Load Obligation Deviation (RTLOD) is preferable to Real Time Adjusted Load Obligation Deviation (RTALOD) as an Operating Reserve cost allocator. Additionally, ISO-NE and NEPOOL filed Attachment 3, which intended to clarify terms. National Grid protested the compliance filing. In its protest, National Grid argued that RTALOD is the appropriate allocator. National Grid among other things argues that using RTLOD to allocate Operating Reserves costs would impose costs on participants who do not participate in the real time market.

86. The Commission finds that ISO-NE has not complied with the December 20 Order directives, since the January 21 compliance filing did not sufficiently clarify the process for allocating Operating Reserves costs. The Commission directs ISO-NE and NEPOOL to submit, within thirty days of the issuance of this order, a compliance filing as directed below.

87. The Commission also directs ISO-NE and NEPOOL in that same filing to address National Grid's protest where it states that using RTLOD to allocate Operating Reserves costs would impose costs on participants who do not participate in the real time market. Specifically, ISO-NE and NEPOOL must explain whether RTLOD would impose costs associated with Operating Reserve Charges on a party not transacting in internal bilaterals for load or internal bilaterals for market (energy) – in other words, whether, if a party had no RTLOD, it could be assessed Operating Reserves charges. ISO-NE and NEPOOL should address the step-by-step example of the allocation process provided by National Grid in its protest and, if they find it to be incorrect, to provide an equivalent correct example. Specifically, National Grid, in that example, indicated that a participant was able to transfer real time market obligations to another participant through an internal bilateral for market (energy) transaction. The Commission directs ISO-NE and NEPOOL to address the accuracy of this statement.

88. The Commission further directs ISO-NE to expand on the purpose of Internal Bilaterals for Market (energy) and to state what this transaction allows a participant to do. ISO-NE and NEPOOL are also directed to explain the impact, if any, Internal

Bilaterals for Market (energy) have on a participant's responsibility to Operating Reserves Charges – in other words, whether a particular participant that had no RTLOD and transacted in real time Internal Bilaterals for Market (energy) could be assessed Operating Reserves charge costs.

89. Finally, the Commission directs ISO-NE and NEPOOL to address why it would be appropriate to charge participants costs associated with emergency energy costs according to RTALOD and charge relevant participants Operating Reserves costs based on RTLOD.

X. Docket No. ER02-2330-004

90. On December 20, 2002, in accordance with the directives in the September 20 Order, ISO-NE filed a status report on the implementation of NE-SMD. This report discusses the efforts under way at that time to implement NE-SMD by March 1, 2003. Additionally, the report discusses the status of various enhancements that the Commission specifically addressed in the September 20 Order including efforts to implement full nodal pricing, Qualified Upgrade Awards process, information process and eligibility rule for resources that are ineligible to set the clearing price, a resource adequacy market, an operating reserves market, and a cost allocation mechanism for transmission upgrades. No comments were filed in response to this status report.[53] The Commission therefore accepts the report.

XI. Old Dockets

91. The Commission will here rule on two pending filings that have in part been rendered moot by subsequent events.

92. Docket No. EL00-62-036. In an order issued on August 27, 2001,[54] the Commission required NEPOOL to revise Sections 18.4 and 18.5 of the Restated NEPOOL Agreement to ensure that ISO-NE will have exclusive responsibility for approval of transmission upgrades. In

[53] NECPUC filed comments on February 3, 2003 under this subdocket; however, the comments address demand response issues contained in the January 21 compliance filing in Docket ER02-2330-007 and we address these comments in that section of this order.

[54] New England Power Pool, 96 FERC ¶ 61,228 (2001).

an order issued on August 28, 2001,[55] the Commission required NEPOOL to make changes in the Restated NEPOOL Agreement to ensure that the revenues from the ICAP deficiency charge are allocated among those participants whose minimum monthly ICAP capability is equal to or greater than their ICAP responsibility. On October 3, 2001, NEPOOL made a filing to comply with these two directives. The October 3 filing was noticed in the Federal Register with interventions, comments and protests due on or before November 14, 2001.[56]

93. Massachusetts Municipal Wholesale Electric Company (MMWEC) filed a protest regarding the new transmission upgrade provisions, asserting that the Commission placed on NEPOOL only the obligation to ensure that ISO-NE would have responsibility for approving transmission upgrades, but that NEPOOL in its compliance filing inappropriately went beyond that obligation to make ISO-NE responsible for approving plans for "(i) any new or materially changed plan for additions to, retirements of, or changes in the capacity of any supply and demand-side resources or transmission facilities rated 69 kV or above subject to control of such Participant, and (ii) any new or materially changed plan for any other action to be taken by the Participant which may have a significant effect on the stability, reliability or operating characteristics of its system or the system of any other Participant." ISO-NE, in its comments, states that the proposed language is appropriate, since it must evaluate all competing options (such as interconnection of new generation) before being able to approve transmission upgrades. ISO-NE also states that the proposed changes would fulfill the commitments entered into by NEPOOL participants and ISO-NE as a result of the negotiations that resulted in the current NEPOOL governance structure, and that the decisions made under Sections 18.4 and 18.5 have competitive implications and are therefore more appropriately made by the independent system operator than by market participants.

94. As to the change that the Commission required as to the allocation of ICAP deficiency charge revenues, ISO-NE stated that no change to the Restated NEPOOL Agreement is required, because the change was already reflected in Section 11.6.2 of the NEPOOL Market Rules that ISO-NE filed on September 27, 2001.

95. Commission decision. The Commission will accept the October 3, 2001 compliance filing as to the directive regarding Sections 18.4 and 18.5 of the Restated NEPOOL Agreement. We are persuaded by ISO-NE's arguments that it is the appropriate authority to approve planning for transmission upgrades and changes to supply and demand-side resources. We will, however, reject that portion of the compliance filing that deals with a deficiency charge for ICAP, since it has been superseded by our acceptance of ISO-NE's and NEPOOL's new Market

---

[55] ISO New England, Inc., 96 FERC ¶ 61,234 (2001).

[56] 66 Fed. Reg. 53602 (2001).

Rule 1, which allocates deficiency charge revenues to all participants with Unforced Capacity (UCAP) obligations that are not deficient going into the UCAP deficiency auction, and to all participants with a surplus going into the deficiency auction.[57]

96. Docket No. ER00-2052-001. In its March 31, 2000 filing in Docket Nos. EL00-62-000 and ER00-2052-000, ISO-NE stated that it would adjust the Reliability Regions it proposed in that filing after discussions with participants. ISO-NE made a filing in Docket No. ER00-2052-001 on May 1, 2000, stating that it has come to its attention that page 38 of Appendix C of ISO-NE's filing is inconsistent with that statement, because it provides that the NEPOOL Participants Committee, rather than ISO-NE, will make those adjustments. ISO-NE therefore proposed to correct this mis-statement and confirm that such Reliability Region adjustments will be made by ISO-NE, and therefore refiled page 38 to Appendix C consistent with this intent. The May 1 filing was noticed in the Federal Register with interventions, comments and protests due on or before May 22, 2000.[58] No protests were filed. The Commission accepts ISO-NE's May 1 filing.

The Commission orders:

(A) The requests for clarification and/or rehearing are granted in part and denied in part, as discussed above.

(B) The compliance filings are hereby accepted in part and rejected in part, as discussed above.

(C) Within 30 days of the date of this order, ISO-NE and/or NEPOOL must file a proposal for a stakeholder process to determine an appropriate set of transmission upgrades for SWCT to receive socialized cost treatment, and an appropriate percentage of the costs of each such project to be socialized, as discussed above.

(D) Within thirty days of the issuance of this order, ISO-NE and NEPOOL must make a compliance filing addressing National Grid's concern that the use of RTLOD to allocate Operating Reserves costs imposes costs on participants who do not participate in the real time market, as discussed above.

[57] December 20 Order at P 78, 80.

[58] 65 Fed. Reg. 31161 (2000).

(E) ISO-NE is directed to continue the system-wide allocation of demand response costs until the extended sunset date included in NEPOOL's and ISO-NE's January 21 compliance filing.

(F) No later than December 31, 2003, ISO-NE and/or NEPOOL must file a compliance report describing the status of each of the five NEDRI recommendations regarding demand response discussed above: (1) inclusion of more flexible bidding processes by removing the requirement that no bid can be smaller than one MW, (2) implementation of an effective, location-based ICAP resource credit, (3) development of an "economic, price-driven" day-ahead market demand response program by 2004, (4) allowing fixed bids each month or capability period in the Day-Ahead Demand Response program along instead of the daily bidding requirement, and (5) permitting demand resources to enroll in both the Day-Ahead and Real-Time Demand Response programs. In the compliance report, NEPOOL will indicate whether NEPOOL has approved these recommendations and how the current programs will be revised, if necessary, for implementation by March 31, 2004.

(G) No later than December 31, 2003, ISO-NE and/or NEPOOL must file an independent in-depth process and impact evaluation and market assessment of its 2003 demand response programs, as discussed above. ISO-NE must provide a similar evaluation by the end of each calendar year until and including December 31, 2005.

(H) No later than March 1, 2004, NEPOOL and ISO-NE must file to place into service a locational resource adequacy mechanism that is compatible with neighboring control areas no later that the start of the Capability Period that starts on June 1, 2004.

(I) No later than December 1, 2005, ISO-NE must file with the Commission a new demand response cost allocation proposal for the period after February 28, 2006.

(J) NEPOOL and ISO-NE are directed to expand the role of the ISO-NE Demand Response Working Group through regularly scheduled meetings and broader participation.

By the Commission. Commissioner Brownell concurring in part with a separate statement attached.

(S E A L)

Linda Mitry,
Acting Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Pool and ISO New England, Inc.	Docket Nos. ER02-2330-004, ER02-2330-006, ER02-2330-007, ER02-2330-008 and EL00-62-054
ISO New England, Inc.	Docket No. ER00-2052-001
ISO New England, Inc.	Docket No. EL00-62-036

(Issued June 6, 2003)

BROWNELL, Commissioner, concurring in part

1. For the reasons set forth in my partial dissent in the Commission's September order on New England's market design, 100 FERC ¶61,287 (2002), I support this order's recognition of the need to take into account the location and deliverability of a resource in determining whether that resource can qualify to supply capacity to a given load and to have such a locational resource adequacy mechanism in place sooner than that contemplated in the September order.

Nora Mead Brownell