103 FERC ¶ 61,082
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Devon Power LLC, et al. Docket No. ER03-563-000

ORDER ACCEPTING, IN PART, REQUESTS FOR RELIABILITY MUST-RUN CONTRACTS AND DIRECTING TEMPORARY BIDDING RULES

(Issued April 25, 2003)

1. In this order, we will deny the requests filed by Devon Power LLC, Middletown Power LLC, Montville Power LLC, Norwalk Power LLC (collectively Applicants) and NRG Power Marketing Inc. (NRG) for Reliability Must-Run (RMR) contracts that recover the full cost-of-service, and instead permit these RMR agreements to recover only certain going-forward maintenance costs. In addition, we direct ISO New England, Inc. (ISO-NE) to establish temporary bidding rules that permit selected RMR peaking units to raise their bids so as to recover their fixed and variable cost-of-service through the market, and change, as necessary, the market rules to allow these bids (when accepted) to set the energy price. These temporary rules are to remain in effect until ISO-NE makes a filing and places into effect certain changes to the market prior to the 2004 summer peak season as identified below. This action will benefit the New England market by establishing locational prices that more accurately reflect the value of additional supply, transmission, and/or demand response resources into the marketplace.

Background

2. On September 20, 2002, the Commission issued an order accepting a new Standard Market Design for New England (NE-SMD) which replaces New England Power Pool's (NEPOOL) former market rules with a new Market Rule 1.[1] Appendix A to Market

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

Rule 1 includes an approach for monitoring and mitigating market power.[2] The Commission stated that this approach identifies resources potentially exercising market power by comparing their current energy supply offers with a proxy for what the resources would bid if they had no market power. The Commission added that when a supply offer significantly exceeds the proxy (referred to as the reference price), an investigation is triggered that may result in mitigation. The Commission further contended that the degree to which a supply offer may exceed the reference price before triggering an investigation depends on whether transmission constraints affect a unit's dispatch or whether it is located in a chronically constrained area identified as a Designated Congestion Area (DCA).

3. In the September 20 Order, the Commission noted that units within DCAs which must be run at certain times to alleviate transmission congestion, and so are likely to have market power at those times, may be classified as RMR units. The Commission accepted a CT Proxy proposal that sets a DCA threshold to serve as a safe harbor bid.[3] The Commission added that if RMR units are not adequately compensated under the CT Proxy safe harbor price, they may apply for a special compensation arrangement under specified RMR contracts. Exhibit 4 to Appendix A of Market Rule 1 contains a pro forma cost-of-service agreement. The Commission also found that RMR fixed costs represent the costs of relieving congestion in specific regions and therefore should be reflected in the cost of energy in those regions.[4]

4. On December 20, 2002, the Commission issued an order[5] that granted in part and denied in part requests for rehearing filed in response to the Commission's September 20 Order. The Commission also accepted two compliance filings made in response to the September 20 Order.

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[2] September 20 Order at PP 16-18.

[3] The CT Proxy proposal, described in Appendix A to Market Rule 1, is based on the estimated price to recover the annual cost of a new combustion turbine unit (CT) for the region over the number of hours it is expected to operate during the year (estimated to be the number of hours the DCA is constrained). This CT Proxy serves as the safe harbor bid for all units in the DCA.

[4] September 20 Order at P 61.

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

5. In the December 20 Order, the Commission approved the CT Proxy proposed by ISO-NE that the CT Proxy price may serve as a safe harbor during all hours, and bids that exceed the CT Proxy safe harbor will be subject to the mitigation review that applies to transmission-constrained periods.

6. Also in the December 20 Order, the Commission reiterated that ISO-NE has the authority to negotiate RMR agreements as are needed to ensure system reliability. The Commission noted that the conditions under which the ISO may enter into RMR agreements are, of necessity, flexible in order to meet the changing demands of the markets. The Commission expected ISO-NE to exercise vigilance to ensure that only those units that are needed to ensure reliability receive RMR contracts, and that those contracts will not be in effect indefinitely but will be limited to the periods during which the units are needed for reliability. The Commission further stated that RMR agreements will be filed with the Commission in accordance with the Commission's rules and regulations and will be effective on the date approved by the Commission.[6]

7. On February 26, 2003, the Applicants filed four cost-of-service agreements, negotiated between NRG and ISO-NE, that pertain to generating units designated by ISO-NE as RMR units. The agreements cover 1,728 MW of capacity located within the Connecticut and Southwest Connecticut (SWCT) DCAs. Applicants contend that while the effort to keep these generators operating arose under the prior NEPOOL rate regime, the recently activated NE-SMD market may not adequately allow these generating units to recover their investments, due in-part to the lack of a locational resource adequacy mechanism and the use of the CT Proxy market mitigation mechanism within DCAs.

8. On March 25, 2003, in response to an emergency motion filed by Applicants, the Commission issued an order that allows ISO-NE to begin collecting funds that are to be disbursed to the Applicants to perform specific maintenance projects so that the units remain available for the upcoming summer peak period.[7]

<u>Notice of Filings, Protests, and Interventions</u>

9. Notice of Applicants' filing was published in the Federal Register, 68 Fed. Reg. 11541 (2003), with comments, protests, or interventions due on or before March 12, 2003. Timely motions to intervene were filed by PPL Wallingford Energy, LLC; PPL EnergyPlus, LLC; Pinpoint Power, LLC; and PG&E National Energy Group LLC.

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[6]December 20 Order at P 33.

[7]Devon Power LLC, 102 FERC ¶ 61,314 (2003).

10. Timely motions to intervene with protests were filed by ISO-NE, the Connecticut Department of Public Utility Control (CT PUC), the Connecticut Attorney General's Office (CTAG), Dominion Energy Marketing Inc. (DEMI), Connecticut Industrial Energy Consumers (CT IEC), National Grid USA (National Grid), Northeast Utilities Service Company (NU), The United Illuminating Company (UI), NSTAR Electric & Gas Corporation (NSTAR), New England Consumer-Owned Entities (NE COE), and the Connecticut Office of Consumer Counsel (CT OCC). NU also filed a supplement to its protest.

11. Timely motions to intervene with comments (or limited comments) were filed by NEPOOL, PSEG Companies, and Mirant Americas Energy Marketing L.P. On March 25, 2003, KeySpan-Ravenswood LLC (KeySpan) filed a motion to intervene out of time. The notices of intervention and the timely, unopposed motions to intervene serve to make the intervenors parties to this proceeding. 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 intervention of KeySpan and accept their comments. Additionally, the Commission rejects a motion filed by DEMI to consolidate this proceeding with PPL Wallingford Energy LLC, et al., Docket No. ER03-421-000, which is currently pending before the Commission.

12. Applicants, pursuant to Rules 212 and 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§385.212 and 385.213 (2002), filed an answer to the protests filed by NU, CT PUC, NE COE, CT IEC, UI, and DEMI on March 12, 2003. Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R § 385.213 (2002), generally prohibits the filing of an answer to a protest. Accordingly, we are not persuaded to allow the Applicants answer and we will reject it.

Discussion of RMR Issues

Demonstrated Need

13. CT PUC, UI, CTAG, CT IEC, NE COE, National Grid USA (National Grid) and NSTAR urge rejection of these agreements by the Commission. Intervenors — CTAG, NSTAR — argue that in order to receive approval for cost-of-service treatment the prospective generator must show that: (1) the unit(s) are needed for reliability; and (2) the unit(s) would be retired if no RMR contract were approved. CTAG and NSTAR assert that the Applicants have not shown that they intend to retire units in the absence of cost-of-service agreements and that the ISO-NE letter does not specify a need for the Applicants' units. CTAG states that covering NRG's entire Connecticut fleet with these

RMR agreements would remove 40 percent of the generation in SWCT from the market. Furthermore, CTAG argues that NRG's Interconnection Agreement with CL&P requires NRG to operate its Norwalk and Cos Cob units until fall 2003 — well past the effective date of the proposed cost-of-service agreements — thus effectively ruling out retirements before then.[8]

14. DEMI, UI, National Grid and CT OCC state that the only evidence to support the need for the RMR proposal is a letter from ISO-NE, which provides no more detail than stating that largely all of Connecticut's existing generation resources are needed for reliability.[9] NE COE emphasizes that ISO-NE did not analyze whether Applicants' cost recovery under NE-SMD would enable them to operate and maintain the units. CTAG argues that any proposal for cost-of-service rate treatment should apply only to generating units that are absolutely necessary, not to entire generating fleets. Similarly, CT OCC speculates that some of NRG's units may merit RMR status but questions whether NRG's entire fleet requires such status.

15. Intervenors further submit that the Applicants' proposal fails to discuss system conditions that justify the proposed cost-of-service agreements and fails to identify potential alternatives. DEMI argues that the Commission should require the Applicants to produce evidence supporting the ISO's determination and such evidence should identify the specific reliability concern, the number of days in which this concern is present, as well as the specific manner in which each NRG units responds to the reliability need.

16. UI argues that cost-of-service agreements do not ensure generation owners return on investment. UI and others assert that NRG’s economic hardship is due primarily to its own investment decisions made in the competitive marketplace and that retail customers or suppliers of standard offer service should not be responsible for poor investment decisions. NE COE submits that a more appropriate analysis would examine whether the DCA CT Proxy threshold price would be sufficient to cover the Applicants' going forward costs, enabling them to operate the facilities needed for reliability.

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[8]CTAG Protest at 10.

[9]Attachment 1 to the Applicants' proposal is a letter, dated February 26, 2003, from Kevin Kirby of ISO-NE to Joseph M. DeVito of NRG Energy, Inc. It states: "...the ISO-NE has conducted a reliability assessment for Connecticut for the years 2003 and 2006 and has determined that absent any transmission improvements or new resources, largely all of the existing resources in Connecticut are needed for reliability, including the NRG units."

Market Implications

17. Numerous intervenors — CT OCC, NE COE, CT DPUC, UI, CT IEC, CTAG — are concerned that approval of NRG's proposal will create incentives for other generation owners to file for cost-of-service agreements, which could have ramifications for Connecticut and NEPOOL wholesale electric markets. Moreover, several intervenors including National Grid argue that having a large percentage of Connecticut's generation operating under cost-of-service agreements could compromise and mute the price-signals needed to induce the expansion of generation, transmission, and demand resources in areas such as Southwest Connecticut. CT IEC argues that approval of the agreements could significantly increase rates of Connecticut consumers. PSEG argues that NRG's proposal will create an "unlevel" playing field among generators, placing generating units that are not subject to cost-based ratemaking at a competitive disadvantage.

18. PSEG urges the Commission to direct ISO-NE and NEPOOL to file on or before June 2003, for implementation as soon as possible, but not later than January 1, 2004, market rules establishing locational capacity requirements similar to those already in effect in the New York ISO.

19. DEMI states that it was able to reduce its exposure to congestion charges through the acquisition of FTRs or other mechanisms as were other entities contracted to supply standard offer load for the balance of 2003. However, there is no such protection from the costs associated with cost-of-service agreements. DEMI argues that this would unfairly saddle it and others with costs they did not cause and — given that standard offer entities are prohibited from passing the additional costs through to load — would not serve to signal new investment. DEMI submits that the solution would be for the Commission to consolidate this proceeding with Docket No. ER03-421-000 and comprehensively address the circumstances that lead to ISO-NE's conclusion that largely all generation in Connecticut should be subject to cost-of-service agreements.

20. CT PUC urges the Commission to approve under RMR agreements "only an amount sufficient to maintain system reliability" — which would only cover deferred and scheduled maintenance outages to ensure dispatch availability for the Summer 2003 peak season. CT PUC asserts that the costs associated with the major maintenance outage expenses should be, on a very short-term basis, socialized through ISO-NE, but only to keep the units operating as a resource when needed for dispatch. Thus the CT PUC "urges the Commission to expeditiously grant approval to allow ISO-NE to provide NRG

with up to $25 million for reliability investments in addition to going forward costs necessary to ensure operation of the units and reliability of the system in SWCT."[10]

21. CT IEC argues that an RMR revenue stream should include: (1) compensation only for going-forward costs of operation; (2) payments for deferred maintenance administered via a mechanism that provides proper oversight that the maintenance is critical for reliability and not for economic purposes; and (3) provisions conditioning the continuance of RMR revenues upon the improved reliability of the generation units.

22. NSTAR argues that cost-of-service pricing should not be available to merchant facilities and the Commission should require the Applicants to reapply for market-based rates if the units are not retired at the conclusion of the cost-of-service agreements. NSTAR further argues that, should prices rise and Applicants take advantage of DCA bidding safe harbor provision, credits may well exceed ISO-NE's payment obligation, in which case, Applicants would retain the revenues. NSTAR argues that it is wrong for merchant generators to collect market prices in good years and resort to cost-of-service guarantees in lean years.[11]

23. NSTAR argues that the Applicants fail to identify a duration for the reliability need of these facilities. NSTAR asserts that the agreements should not be subject to automatic annual extension without action from ISO-NE. Moreover, NU and NSTAR submit that these contracts must be subject to annual review by the Commission and not allowed to continue indefinitely.

24. UI argues that the cost-of-service agreements do not give the ISO sufficient flexibility to respond to changing circumstances, for example, implementation of NE-SMD or new resources being introduced into SWCT. UI and NU urge the Commission to reduce the termination notice period from 120 days, as proposed by the Applicants, to 60 days in order to permit the ISO to terminate the agreement if there is no longer a need for the resources. NSTAR asserts the cost-of-service agreements should list identical provisions for ISO-NE termination (Sections 2.1.2 and 2.2.1 of the Applicants' proposed cost-of-service agreements stipulate 60 days and 120 days notice, respectively) and in any case 60 notice is reasonable, as was found in *Sithe New Boston*.[12]

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[10]CT DPUC Motion at 6.

[11]NSTAR Protest at 8.

[12]*Sithe New Boston LLC,* 98 FERC ¶ 61,164.

25. CT DPUC asserts that the Commission should direct ISO-NE and NEPOOL to make filings, on an emergency/expedited basis, to revise or amend NE-SMD in order to ensure adequate levels of compensation for generators providing needed reliability products and to incent market participants to build infrastructure, implement demand-side management programs, or take other appropriate measures to reduce the need for NRG's units or provide for appropriate compensation to these units.

26. CT DPUC further argues that since Connecticut ratepayers will pay most, the Commission should order that the ISO NE be required to examine the reliability need for any of these units upon written request by the CT DPUC and issue a finding within 60 days of such a request.

Commission Response

27. The RMR agreements filed by the Applicants in this proceeding were negotiated with ISO-NE in accordance with MRP 17.3. The Applicants state that they are not required to establish the need for these agreements because they were negotiated under the authority of ISO-NE.[13] ISO-NE states that it has conducted a reliability assessment for Connecticut for the years 2003 and 2006 and has determined that, absent any transmission improvements or new resources, largely all of the existing resources in Connecticut are needed for reliability.[14] ISO-NE further states that the appropriate format to be used for cost-of-service agreements is the pro forma RMR agreement that is a part of Market Rule 1.[15]

28. ISO-NE is concerned that, under its current market rules and mitigation policies, some generators needed for reliability in load pockets – i.e., in DCAs – may be unable to recover their full fixed and variable costs and not be available for reliability. Ultimately, New England proposes to allow for such cost recovery with a combination of scarcity pricing and location-specific capacity payments. Until these features are implemented, however, ISO-NE has proposed (and the Commission has accepted) relaxed mitigation rules for units in DCAs with the intent to provide for sufficient cost recovery. In particular, under Market Rule 1, generators in DCAs would be permitted to submit bids

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[13]Application at fnt.6.

[14]Application at Attachment 1.

[15]Market Rule 1, Appendix A, Exhibit 4, Original Sheet Nos. 260-287. Market Rule 1 was approved by the Commission as part of the September 20 Order approving NE-SMD (100 FERC ¶ 61,287, 2002).

up to the level of the fully allocated cost-of-service of a new combustion turbine, the "CT Proxy" bid. This safe harbor bid includes a fixed cost adder designed to recover the fixed costs of a new CT over the total number of hours of congestion in the DCA. However, NRG states that its units operate during far fewer hours, and if it receives only the CT Proxy price for the power it supplies, it will fail to recover its costs.[16] NRG asks the Commission to approve temporary RMR contracts for its units that would pay them their full cost-of-service until ISO-NE is able to implement locational ICAP or some other form of locational capacity requirement.

29. RMR contracts suppress market-clearing prices, increase uplift payments, and make it difficult for new generators to profitably enter the market. That is because under current market rules, generators operating under a cost-of-service RMR contract must offer power under a Stipulated Bid Cost that includes stipulated marginal, start-up and no-load costs. The units are then entitled to a monthly fixed cost payment to the extent that revenues earned from the energy market, including any payments for start-up and no-load costs, do not recover allowable capacity costs and fixed O&M costs. As a result, expensive generators under RMR contracts receive greater revenues than new entrants, who would receive lower revenues from the suppressed spot market price. In short, extensive use of RMR contracts undermines effective market performance. In addition, suppressed market clearing prices further erode the ability of other generators to earn competitive revenues in the market and increase the likelihood that additional units will also require RMR agreements to remain profitable. 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.

30. The Commission discussed the subject of RMR agreements when ruling on the NE-SMD proposal in the September 20 Order. The order reaffirmed previous rulings that ISO-NE has the authority to enter into cost-of-service RMR agreements, the flexibility to address specific RMR situations when entering into agreements, and the requirement to file the agreements for review by the Commission.[17] 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

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[16]NRG states that the average overall capacity factor of the facilities subject to the proposed agreements is 8 percent. Filing at 5.

[17]100 FERC ¶ 61,287 at P 50.

agreements will be in effect only for the period during which the units are needed for reliability.[18]

31. The Commission believes that RMR agreements should be a last resort and that the proliferation of these agreements is not in the best interest of the competitive market as they affect other suppliers participating in this market, especially those suppliers operating within the same DCA. Implementation of NE-SMD provides some of the needed price signals in this regard; however we believe, as many commenters in this proceeding as well as the NE-SMD proceeding have noted, a location-specific capacity requirement or a deliverability requirement is needed so that energy markets alone are not the only way for suppliers in DCAs to recover costs.[19] We believe that the current situation in NEPOOL may not allow suppliers in DCAs an adequate opportunity to recover their costs and that a location-specific capacity requirement must be in place. ISO-NE and NEPOOL need to expeditiously address the issue of resource adequacy within the DCAs as well as other transmission constraints in New England that include areas affected by export constraints as well.

32. On the basis of the foregoing discussion, we will deny the Applicants' request to recover their full cost-of-service through an RMR contract and instead: (1) direct the recovery of only forward maintenance costs through the RMR; and (2) direct ISO-NE to modify its market power mitigation mechanism to permit selected high cost but seldom run units in DCAs to raise their bids so as to recover their fixed and variable costs through the market (a Peaking Unit Safe Harbor Bid). These temporary rules are to remain in effect until ISO-NE makes a filing and places into effect certain changes to the market prior to the 2004 summer peak season as identified below. In this regard, we have changed only the form in which the Applicant's will be able to recover their fixed and variable costs, i.e., use of a safe harbor bid within the market rather than an RMR contract.

33. Upon further review of Market Rule 1, we will, pursuant to Section 206 of the Federal Power Act, 16 U.S.C. 824e, revise that Market Rule. Specifically, first, we find that Market Rule 1 shall include temporary mitigation rules to be effective June 1, 2003

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[18] 100 FERC ¶ 61,344 at P 33.

[19] In the September 20 Order we directed NEPOOL to develop a locational mechanism together with the other Northeastern ISOs. At that time, the assumption was that the region was pursuing a Northeastern RTO. Consequently, the Commission did not provide a date certain when it expects the mechanism to be in place, only that it be implemented in accordance with a final SMD rule.

that increase the safe harbor energy bids (used in the mitigation process in determining acceptable bids) to a level that includes both a variable cost component and a fixed cost adder for capacity in each DCA that had a capacity factor of 10 percent or less during 2002 (Peaking Units). The fixed cost adder for each such unit should be designed to recover the unit-specific fixed costs (adjusted downward, in the case of units covered by RMR contracts, to account for the costs recovered in the RMR contract) over the number of megawatt hours supplied in the preceding year. The safe harbor energy bids for these units would be the sum of the unit's variable cost and the adjusted fixed cost adder.

34. Our reason for increasing the safe harbor energy bids of these units is to provide a market mechanism for high cost, seldom run units to recover their fixed costs. Since ISO-NE dispatches energy in order of energy bids, capacity with a capacity factor of 10 percent or less for the year is likely to be among the most expensive energy-producing capacity in the DCA. When such capacity is called upon to produce energy, demand is likely to be pressing upon the total capacity in the DCA, and thus, higher prices are likely to be economically justified. The current CT Proxy is designed to allow a new CT to recover its fixed costs over all hours of congestion in a DCA. Units that produce energy in substantially fewer hours, such as the Applicants' units, are not likely to be able to recover all of their fixed costs under the current CT Proxy.

35. Second, we find that the Market Rule shall provide that the energy bids of peaking units are eligible to determine LMP. As a result, when a peaking unit is called, all sellers will be able to receive a high market price and recover fixed costs. This feature will encourage entry by new generators. We will direct ISO-NE to make compliance filings to reflect these changes in Market Rule 1.

36. Third, we will eliminate the current CT Proxy mechanism. Under our modified mitigation approach, energy bids above a unit's safe harbor energy bid would be subject to possible mitigation. However, since our new Peaking Unit Safe Harbor energy bid mechanism will permit higher bids and prices during the small number of hours when demand approaches total capacity, we find there is no need to permit other generators to bid up to the current CT Proxy in order to attract new investment. Moreover, permitting these other generators to bid up to the current CT Proxy could permit them to exercise market power by increasing prices when supplies are not scarce. Therefore, we will eliminate the current CT Proxy mechanism. By eliminating the current CT Proxy mechanism, we expect energy prices to be lower during periods of ample supply, when the units eligible for the higher Peaking Unit Safe Harbor energy bids are not needed.

37. Additionally, we will direct ISO-NE to file no later than March 1, 2004 for implementation no later than June 1, 2004,[20] a mechanism that implements location or deliverability requirements in the ICAP or resource adequacy market as discussed in the September 20 Order so that capacity within DCAs may be appropriately compensated for reliability.

Discussion of RMR Agreements

Changes to the Pro Forma Agreements

38. ISO-NE opposes two revisions made by the Applicants to the *pro forma* agreement: (1) the Reliability cost-of-service Tracker as described in Section 5.1.3 and (2) the non-performance penalty, outlined in Section 3.4. In both cases the ISO urges the Commission to suspend the filing to permit the parties to devise an acceptable provision through settlement discussions.

39. National Grid states that Section 3.1.2 of the Applicants' proposed tariff appropriately protects against the receipt of revenues in excess of the cost-of-service and regulated return via an offset provision. However, National Grid believes that Section 3.3.2, which specifies the actual revenue crediting mechanism, references an offset of only those amounts received from the NEPOOL market. National Grid argues that the Commission should require modifications to Section 3.3.2 which make clear that it does not limit the scope of the revenue offsets provided for in Section 3.1.2.

40. NU states that the Applicants have revealed in this filing, for the first time, that they have been collecting revenue since September 2001 as part of unfiled Voluntary Mitigation Agreements (VMAs). NU argues that the Applicants should be required to divulge the exact amounts of payments, where those used to maintain plants, and whether the VMAs should be considered as offsets to the operating costs of the plants. NU also argues that the Applicants owe in excess of $10 million for station service to plants. NU asserts that permitting the Applicants to collect for station service would violate cost causation principles in the cost-of-service agreements.

41. DEMI lists several instances where provisions of the cost-of-service agreements proposed by NRG diverge from those of the pro forma cost-of-service agreements, which

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[20] This date coincides with the start of the Capability Year for assigning UCAP requirements to NEPOOL participants.

was approved in the NE-SMD proceeding.[21] DEMI argues that NRG neither identified nor offered an explanation or justification for these differences. DEMI submits that these changes may be unjust and unreasonable and urges the Commission to review the proposed agreements' provisions to determine if they are just and reasonable.

42. CT IEC and National Grid oppose granting Applicants the right to terminate their cost-of-service agreements. CT IEC states that this is fraught with potential for abuse in that the Applicants' units are strategically located and are important for preserving reliability. CT IEC argues that the Applicants may be tempted to exploit their position and threaten termination of the cost-of-service agreements in an effort to squeeze additional revenues from Connecticut load.

43. NSTAR and DEMI argue that Section 6.2 of the pro forma cost-of-service agreements provides for ISO-NE discretionary termination if a force majeure event continues in excess of thirty days whereas the cost-of-service agreements proposed by the Applicants have no such provision.

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[21]Section 2.5 of the cost-of-service agreements acknowledges that the unit owner, its agent and certain affiliates may file a petition under Chapter 11 of the Bankruptcy Code during the term of the cost-of-service agreements and specifies certain provisions that would apply in the event that such a petition is filed.

1. Section 3.1.2 of the cost-of-service agreements amends the pro forma RMR agreement's treatment of installed capacity (ICAP) revenue credits and instead specifies price levels for certain time periods in lieu of the pro forma contract's requirement that all ICAP revenues be offset against payments to the resource under the agreements.

2. Section 3.2.2 of the cost-of-service agreements amends the pro forma agreement's definition of Fuel Index Price, which is a component of the Stipulated Bid cost-of-service, by allowing NRG and ISO-NE to renegotiate the Fuel Index Price if either party believes the Fuel Index Price calculated by ISO-NE does not accurately reflect NRG's actual cost of fuel.

3. Certain provisions of the cost-of-service agreements depart from the pro forma by allowing NRG to substitute performance by one unit when another unit is unable to perform, see Section 5.2.2(b), and, in certain circumstances, to recover from the ISO the costs of bringing a substitute unit into service, see Section 5.2.2(e).

44. National Grid states that Section 2.2.3 of the Applicants' proposed cost-of-service agreements — which is not contained in the pro forma agreement — permits the Applicants to terminate the cost-of-service agreement, subject to consent of ISO-NE. National Grid argues that the proposed agreements offer no specific terms or conditions as to when the agreements may be terminated and no justification for departure from the pro forma agreement. National Grid believes that this appears to enable the Applicants to terminate the agreements when they so desire.

45. NE COE protests the absence of a provision preventing Applicants from delisting a resource. NE COE states that under Market Rule 1, generators are permitted to delist a resource from the day-ahead and real-time markets, which a generator typically undertakes to be able to sell in New York markets. NE COE argues that generators receiving support under cost-of-service agreements should not be permitted to remove the relevant facilities in seeking sales outside of New England. Moreover, NE COE submits that the Applicants' units are needed to meet reliability and thus there is no reason to permit Applicants to delist.

Cost-of-service Tracker

46. Numerous intervenors express opposition to the Applicants' proposed section 5.1.3, entitled Reliability Projects that is not included in the pro forma agreement. This Section provides a cost tracking provision to compensate the Applicants for the costs of specifically identified Reliability Projects to ensure that the Applicants complete this needed maintenance in order to keep the facilities in operation so that they are available when called upon by the ISO. Generally speaking, intervenors do not oppose the theory behind the tracker. However, many parties object to the lack of oversight, which, if in place, could ensure that the funds are spent on the intended maintenance and will also serve to protect the funds collected by ISO-NE in the event of an NRG bankruptcy petition. DEMI opposes the absence of prior review or approval of the costs; CT DPUC and NU urge the Commission to direct that funds be placed in escrow; CT IEC states that there are no measures to ensure funds will be dedicated to necessary expenditures; and National Grid argues that costs flowing through the tracker should be identified and that the tracker mechanism should be modified to limit the Applicants to recovery of an amortized portion of any multi-year maintenance or capital investment. NEPOOL, while not taking a formal position on the proposed reliability agreements, asks the Commission to carefully consider the implications of a potential bankruptcy filing by one or more of the applicants on the advance payment provisions for the major maintenance expenses.

Commission Response

47. The Commission addressed the cost-of-service tracking mechanism for Reliability Projects in the March 25 Order. The units under the proposed RMR agreements are needed this year for reliability. They need to undergo maintenance in order to operate, and NRG may not be able to raise the funds to pay for maintenance costs without an assured revenue source, such as would be provided by an RMR contract. However, it appears that these units do not need to be guaranteed their full cost-of-service to remain in operation. The cost-of-service tracking provisions contained in Section 5 of these agreements assures payment only of going forward maintenance costs. This is a provision that may not be applicable to all RMR agreements; however, we consider it applicable here because the Applicants may not otherwise be in a financial position to fund maintenance in advance of revenue. The escrow modification we ordered in the March 25 Order will alleviate concerns that the funds collected from participants are used for maintaining these units. While we deny the remainder of the RMR agreements, this provision will ensure the units are maintained and operational. Because the bid ceiling discussed above would provide the units with an opportunity to recover their fixed costs, we direct ISO-NE and the Applicants to modify the agreements so that the amounts paid by NEPOOL participants in accordance with Section 5, Reliability Projects will be credited against the fixed cost-of-service portion of the new reference price bid ceiling.

Delivery Standard

48. Several intervenors take issue with NRG's proposal to reduce the delivery standard according to Section 3.4.2 of the proposed cost-of-service agreements.[22] ISO-NE indicates that it cannot accept the proposed standard absent empirical evidence that such a revision is appropriate.[23] NU submits that ratepayers should not be required to pay for RMR service if they receive a diminished reliability benefit and further suggests considering a reduction of the Applicants cost-of-service recovery if they cannot meet the

[22]Section 3.4.2 of the Applicants proposed cost-of-service agreements states that a unit shall be deemed to be in full compliance if the unit delivers in any hour at least 95% of the requested MW or not more than 5 MW less than the requested MW. The pro forma cost-of-service agreement, provides for at least 97% and not more than 2 MW less than the requested MW.

[23]ISO-NE states that necessary evidence has not been provided and supports the 97% or not less than 2 MW standard required in the pro forma agreement in Market Rule 1.

ISO-NE designated performance standards. CT OCC asserts that NRG's request is completely inappropriate especially in the context of the company's rather high cost-of-service recovery requests. CT IEC concludes that NRG hopes to secure the most amount of money for the least amount of output based on NRG's statement that the facilities may not be able to meet the reduced performance standard. CT IEC argues that in order to ensure reliability in Connecticut, which is the goal of cost-of-service agreements, the Applicants' generating units must meet their performance goals and any failure to do so must be strictly penalized. NSTAR argues that the Applicants must not be allowed to undermine ISO-NE's need to know what it can count on and when in a constrained dispatch. NEPOOL, without taking a formal position, asks the Commission to carefully consider the deviation from the pro-forma agreement with regard to the diminished performance standard.

Commission Response

49. The Commission is not convinced by the Applicants' statements that the non-performance penalty standards contained in Section 3.4.2 of the agreements need to be changed from the pro-forma agreements. We therefore deny this change.

Cost-of-service

50. ISO-NE has not reviewed rate-related information and states that it does not take any position on the appropriateness of rates requested by the Applicants. However, ISO-NE does confirm that the units specified "are necessary to support reliability in Connecticut and [the ISO] is prepared to execute cost-of-service agreements with the Applicants."[24] Further, the ISO is prepared to "execute the Agreements in substantially the same from as they have been submitted," subject to any changes ordered by the Commission.[25]

51. Numerous intervenors — DEMI, NU, CT CPUC, CT IEC, CTAG, NSTAR and CT OCC — believe NRG's proposed rates exceed the bounds of "just and reasonable" ratemaking and call for suspending the filing and setting it for hearing. Intervenors also address specific items of NRG's filed cost-of-service including the proposed return on equity of 14 percent, cost of capital (NRG proposes 9.05 percent cost of credit),

[24]Comments of ISO-NE at 3.

[25]The Commission notes that the ISO-NE raises concerns regarding the deviations from the pro-forma RMR agreement that the applicants proposed in the filing—the Cost Tracking mechanism and the reduction in the performance standard.

accumulated deferred income taxes, depreciation (NRG uses 6.6 years to calculate accumulated depreciation), net negative salvage value (NRG has increased its depreciation base by $92,420,000), operations and maintenance expenses, interconnection rights, and recovery of an acquisition premium.

Commission Response

52. Applicants filed proposed rates to recover the costs of all subject generating units in each power plant, i.e., separate rates for Devon, Middletown, Montville, and Norwalk. Under this approach all of the units under each RMR Agreement would have received the same rate regardless of which unit(s) run at the plant. The rejection of the agreements and the Commission's changes to the mitigation rules discussed above renders as moot the cost-of-service analysis for the original intended purpose of developing specified rates for the recovery of fixed and variable costs of each plant. Under the Commission's directive, a Peaking Unit Safe Harbor bid ceiling with a fixed cost adder will need to be developed for each unit or plant to replace the CT Proxy for these peaking units based on the amount of generation produced during the previous year, i.e. 2002. The cost-of-service analyses filed by the Applicants will therefore need to serve as the basis for the determination of the Peaking Unit Safe Harbor.

53. Interveners have raised several issues regarding the cost-of-service analysis including rate of return, depreciation rates, and accumulated deferred income taxes (ADIT). In addition, the Commission performed a cost-of-service analysis for each Agreement based on the information provided in the filing. The Commission identified several cost-of-service items that were not fully supported by the Applicants in their filing and made adjustments as follows: a return on equity of 13.39% (based on Commission Staff's preliminary analysis), the addition of ADIT, and the elimination of net negative salvage and associated depreciation expenses. The Commission's analysis supports fixed charges of: $21,154,792 for the Devon units; $17,687,684 for the Norwalk Harbor units; $19,327,732 for the Montville units; and $45,262,975 for the Middletown units. These values, subject to adjustment for all revenues received from other sources, are to be used to develop fixed cost adder and the initial Peaking Unit Safe Harbor bid ceilings for these units.

54. Issues that are driving how the Commission will deal with the filed costs-of-service include: the need for intervenors to comment; the need for the Peaking Unit Safe Harbor to be implemented in short order; and the inability to order refunds because of the interaction between Peaking Unit Safe Harbor and the market price of electricity. The safe harbor bids by definition are approximations; and therefore, the Commission will provide an avenue for intervenors to comment in order to accommodate the above

driving factors. The Commission will allow the costs-of-service with the adjustments discussed above to serve as the basis for developing initial Peaking Unit Safe Harbor to be placed into effect with the market mitigation measures described above. We will allow parties to comment specifically about the costs-of-service as they pertain to the development of the Peaking Unit Safe Harbor bid levels as well as to allow the Applicants to comment on and to support the items that the Commission adjusted in developing the above fixed charges within 30 days. The Commission will set an expedited timetable for the resolution of any issues. Changes to the costs-of-service resulting from this process will be reflected in recalculated reference prices that will go into effect on a going forward basis from the date of an order that establishes revised Peaking Unit Safe Harbor levels.

The Commission orders:

(A) The proposed agreements are hereby accepted for filing, as revised as directed in ordering paragraph B below, suspended to become effective February 27, 2003, subject to refund and the escrow arrangements consistent with the March 25 Order.

(B) Applicants are hereby directed to file revised agreements within 30 days of the date of this order, that provide only for the recovery of costs related to the Reliability Projects as discussed in the body of this order.

(C) ISO-NE is hereby directed on or before May 30, 2003, to make a compliance filing to revise the Proxy CT mitigation measures contained in Market Rule 1 and to develop Peaking Unit Safe Harbor bid ceilings as discussed in the body of this order.

(D) ISO-NE and NEPOOL are directed to file revised ICAP rules no later than March 1, 2004, as discussed in the body of this order.

(E) The Secretary is hereby directed to publish a copy of the order in the Federal Register.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.