

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 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,<sup>20</sup> 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 unfilled 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 was approved in the NE-SMD proceeding.<sup>21</sup> 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.

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

<sup>21</sup> 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).

<sup>20</sup> This date coincides with the start of the Capability Year for assigning UCAP requirements to NEPOOL participants.