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 — Docket Nos. ER03-210-000 and ER03-210-001

ORDER ACCEPTING FILING

(Issued January 31, 2003)

1. In this order, the Commission rules on a filing by the New England Power Pool Participants Committee (NEPOOL) proposing amendments to the NEPOOL Open Access Transmission Tariff (OATT) and Restated NEPOOL Agreement (RNA), and NEPOOL's Market Rule 1 relating to the implementation of a standard market design for New England. We accept the filing, effective as of the date of this order. Our action here promotes the development of competitive power markets and the benefits that flow from such markets.

BACKGROUND

2. On July 15, 2002, NEPOOL and ISO New England, Inc. (ISO-NE) jointly filed their proposed Standard Market Design for New England (NE-SMD),[1] which, most significantly, will provide congestion pricing through the use of locational marginal pricing (LMP) and enable participants to hedge against congestion costs through the use

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[1]The standard market design submitted here for New England is not identical to the design contained in the Notice of Proposed Rulemaking issued by the Commission on July 31, 2002 (Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 100 FERC ¶ 61,138 (2002) (SMD NOPR)), in which the Commission proposed a standard market design for wholesale electric markets throughout the nation. NEPOOL and ISO-NE acknowledge that "further modifications to this New England SMD may be necessary to conform this market design with the outcome of the Commission’s proposed rulemaking on standardized transmission services and wholesale market design." Transmittal Letter at 1 n.3.

of Financial Transmission Rights (FTRs). As part of implementing NE-SMD, NEPOOL proposed to cancel the existing NEPOOL market rules (NEPOOL Rate Schedule 6) and replace them with a new Market Rule 1. The Commission accepted the NE-SMD filing on September 20, 2002,[2] and denied rehearing in part and granted rehearing in part on December 20, 2002.[3]

3. On November 22, 2002, NEPOOL made the instant filing to further revise the NEPOOL OATT, the RNA, and Market Rule 1. NEPOOL proposes to revise Market Rule 1 to remove the special pricing provisions for Maximum Generation Emergencies (a condition in which NEPOOL calls on all resources), changes to Operating Reserve Charges and to the agreements for reliability must run units, and changes to govern a failure to follow dispatch instructions with regard to distinguishing between types of resources. NEPOOL also proposes to move certain material relating to market operations, accounting, and calculation of Installed Capacity (ICAP) from its manuals to Market Rule 1. NEPOOL also here deletes obsolete provisions of the existing NEPOOL OATT, places the system of requiring advance reservations for Through or Out Service with a system of economic merit order scheduling for external transactions, and adds a new schedule for Special Constraint Service in which local reliability concerns require dispatch changes. Finally, NEPOOL makes conforming changes to the RNA. NEPOOL requests an effective date of January 31, 2003 for all of these changes.[4]

4. Notice of the November 22, 2002 filing was published in the Federal Register,[5] with interventions and protests due on or before December 13, 2002. Notice of the

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

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

[4]In NEPOOL's original November 22, 2002 filing, it asked for an effective date of January 21, 2003 for the filing. Subsequently, however, NEPOOL notified the Commission that it would not object to the Commission's not acting on this filing until January 31, 2002, and waived its right under Section 205 to an earlier ruling. It also agreed to an effective date of January 31, 2003. On January 10, 2003, NEPOOL amended its filing, providing a copy of an attachment inadvertently omitted from the prior filing.

[5]67 Fed. Reg. 71960 (2002).

January 10, 2003 filing was published in the Federal Register,[6] with interventions and protests due on or before January 21, 2003.

5. The Maine Public Utilities Commission (Maine Commission) filed a notice of intervention. Timely motions to intervene were filed by PPL Wallingford Energy LLC and PPL EnergyPlus LLC (PPL), Northeast Utilities Service Company and Select Energy (NUSCO), H.Q. Energy Services, U.S. (H.Q.), and Mirant Americans Energy Marketing, L.P., et al. (Mirant). Timely motions to intervene, comments and protests were filed by ISO-NE, PG&E National Energy Group (PG&E), Exelon Generation Company and Exelon New England Holdings, LLC (Exelon), Central Vermont Public Service Corporation and Vermont Electric Power Company (Vermont Utilities), TransÉnergie U.S. Ltd. and Cross Sound Cable Company (TransÉnergie), Duke Energy North America (DENA), Long Island Power Authority (LIPA), Cape Wind Associates LLC (Cape Wind), the New England Conference of Public Utility Commissioners (NECPUC) and MASSPOWER and the Pittsfield Generating Company (MASSPOWER). Motions to intervene out of time and comments were filed by the New England Renewable Power Producers Association (NERPPA) and FPL Energy LLC (FPL). NEPOOL and ISO-NE filed a joint answer to the protests. On January 17, 2003, Exelon submitted a motion for leave to file a response to NEPOOL's and ISO-NE's joint answer.

DISCUSSION

Procedural Issues

6. 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 their interest, the early stage of this proceeding and the absence of undue delay or prejudice, we find good cause to grant the untimely, unopposed interventions of NERPPA and FPL. 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 protest or an answer unless permitted by the decisional authority. We will permit NEPOOL's and ISO-NE's joint answer to the protests on the basis that it has provided factual information that has assisted us in ruling on this application. We will deny the response filed by Exelon to NEPOOL's and ISO-NE's joint answer on the basis that it has provided no new information to assist us in ruling on this application.

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[6] 68 Fed. Reg. 2537 (2003).

Analysis

7. **LMP Calculation and Congestion on the Cross Sound Cable.** The Cross Sound Cable (CSC) is a merchant transmission facility (MTF) providing service between New Haven, Connecticut and Shoreham, New York, constructed and owned by an affiliate of TEUS. Under proposed Section 25D of the NEPOOL tariff, NEPOOL proposes to schedule transmission service at the interface between the CSC and NEPOOL's PTF facilities[7] based on economic merit order. NEPOOL asserts that this system is more compatible with the regime of financial (rather than physical) transmission rights which NE-SMD seeks to promote.[8] However, interconnections between the CSC and NEPOOL PTF facilities will have advance reservation requirements and physical transmission rights obtained by contract. All of the physical capacity on the CSC has been purchased by LIPA. TEUS and LIPA both protest certain aspects of NEPOOL's treatment of the CSC in implementing Market Rule 1 relating to the calculation of LMP and scheduling rights across the MTF.

8. TEUS is concerned that NEPOOL will calculate FTRs and associated LMPs in a manner that does not reflect the true value of delivered energy across the CSC, and states that Market Rule 1 does not provide an appropriate and consistent framework for LMPs at both ends of the CSC. TEUS argues that because there is no basis for correctly calculating the values of FTRs, parties' physical rights must therefore be retained. TEUS states that, although NEPOOL intends to retain physical rights and intends that the flows over MTFs (including the CSC) will be limited to those with reservations and also that there will be no congestion in real-time,[9] TEUS is concerned that there are conflicting provisions in the NEPOOL tariff that undermine these intentions. Specifically, TEUS cites Section 7.2.2 of Market Rule 1, which provides for the creation of FTRs between any two points for which ISO-NE calculates and posts LMPs. According to these provisions, TEUS states, ISO-NE will create FTRs across the CSC. TEUS states that

[7]"Pool Transmission Facilities" or "PTF" are the pool transmission facilities defined in Section 15.1 of the Agreement, and any other new transmission facilities which the Reliability Committee determines, in accordance with criteria approved by the Participants Committee and subject to review by ISO-NE, should be included in PTF. The costs of PTF facilities are recovered from all NEPOOL members, based on the understanding that they serve all members. All other facilities are non-PTF, including merchant transmission projects such as the CSC.

[8]NEPOOL Transmittal Letter at 5.

[9]TEUS protest at 6.

ISO-NE will calculate the LMP on the NYISO side of the CSC (Shoreham node) by adding losses across the CSC to the NEPOOL side (New Haven node), but that this method will not reflect the true marginal price of electricity delivered at the Shoreham node, because there will be no congestion between Shoreham and New Haven. TEUS is concerned that the NEPOOL tariff will assign FTRs to the CSC and does not explicitly make the accommodations regarding the CSC that NEPOOL has stated that it will make.[10] TEUS requests that Section 2.6 of Market Rule 1 be revised to state that on an interim basis, ISO-NE will not calculate an LMP for the Shoreham node and will instead continue to use the current system of advance reservation and physical transmission rights.

9. LIPA also takes issue with the proposal to create a single node for the majority of the New York/New England interface, on the basis that averaging between two transmission organizations may not send proper price signals for the efficient interchange of energy between the two ISOs. LIPA explains that NEPOOL's currently proposed Section 2.7(e) to Market Rule 1 provides that ISO-NE will establish external nodes on the basis of factors including tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices and inter-regional trading impacts. LIPA believes that in addition to the above, ISO-NE should establish external nodes so as to maximize the use of the external interface through facilitation of market price signals while maintaining the reliable operation of the NEPOOL Transmission System. LIPA also asks the Commission to require the filing of all external node designations with the Commission for review and comment.

10. NEPOOL and ISO-NE state in response that the market is designed so that transactions across the CSC will be scheduled based on physical reservations subject to the physical limitations of the CSC and that, thus, there will never be congestion costs associated with these facilities. NEPOOL and ISO-NE further state that pricing at external nodes is consistent with the pricing at other nodes in NEPOOL and since the external interface’s transfer limit will never be exceeded, the next economic MW at the external node (the Shoreham side of the CSC) will be the same as that for the “next

[10]TEUS states that "NEPOOL acknowledges its intent to retain physical rights for certain transmission interconnections (including the CSC)," citing to the statement on page 12 of the Transmittal Letter to the instant filing in which NEPOOL states that "Non-PTF interconnections will continue to have advance reservation requirements and physical rights associated with them and their own specific contractual or open access tariff arrangements," footnote omitted. See TEUS protest at 6.

inward" NEPOOL node (the NEPOOL side of the CSC at New Haven). Therefore, they state that the energy and congestion component of the LMP will be the same on either side of the line except for losses. NEPOOL and ISO-NE acknowledge that, because there is no congestion across the CSC, there is no basis for allocating FTRs or ARRs.[11] NEPOOL and ISO-NE also state that pricing within NEPOOL reflects the true value of delivered energy and that enhancements designed to improve pricing between regions are being addressed in other proceedings.

11. **Commission Conclusion.** Non-PTF facilities such as the CSC can only be used by those holding reservations which ensure that the facility is not oversubscribed; thus, there will be no congestion on the CSC and no need for FTRs to hedge against it, and NEPOOL and ISO-NE concede that they will not create FTRs for the CSC.[12] Nonetheless, ISO-NE still needs to calculate a price on the Shoreham side of the CSC in order for ISO-NE to have a node, with a price, so that it may appropriately account for losses. NEPOOL and ISO-NE explain in Attachment A to their answer that this price serves as an administrative price ("proxy LMP") at the external node. We recognize that this price does not reflect the actual marginal price of electricity at that location. While we accept NEPOOL's explanations and will not require NEPOOL to establish new external nodes, as LIPA requests,[13] we will, however, require NEPOOL to add provisions to Section 25D or to Schedule 18 of the NEPOOL Tariff that specifically state that neither FTRs nor congestion costs will be assigned to the CSC as long as it remains classified as non-PTF.

12. **Scheduling Rights on the CSC.** LIPA is also concerned with the scheduling priorities that it will receive on NEPOOL's PTF facilities, and the effect that those scheduling priorities may have on LIPA's firm transmission rights on the CSC. Under its proposed Section 25D(c) of the tariff, NEPOOL proposes to schedule transmission

[11] Auction Revenue Rights (ARRs) are rights to receive FTR Auction Revenues from the sale of FTRs.

[12] We also note that, in an internal ISO-NE document provided by NEPOOL and ISO-NE, ISO-NE's vice president for market development stated that "FTRs will not be offered over any non-PTF tie facilities [including] Cross Sound Cable." Memorandum from David LaPlante to NEPOOL Markets Committee, December 11, 2002 at 3, Attachment A to joint answer of NEPOOL and ISO-NE.

[13] Additionally, the lack of a single market across New York and New England makes an actual LMP at Shoreham irrelevant to NEPOOL – a major seams concern of this Commission and not the subject of this proceeding.

service over MTF "based on economic merit order in accordance with NEPOOL System Rules." LIPA states that it was awarded transmission rights to the CSC after participating in a Commission-approved open season, and it is concerned that proposed Section 25D would subject its scheduling priority to curtailment in favor of other parties who purchased CSC transmission that LIPA may release on the secondary market.[14] LIPA argues that its transmission priorities on the CSC should not be overridden as a result of NEPOOL's modifications to implement SMD and that NEPOOL should recognize LIPA's scheduling priority over other NEPOOL facilities, as such action would diminish the economic value of merchant facilities such as the CSC. LIPA references the Commission's policy not to require abrogation of contract rights as stated in Order 888 and as reiterated in the Commission's September 20 Order regarding NE-SMD. LIPA also references the treatment given to Excepted Transactions under the NEPOOL tariff, which provides for a continuation of physical rights with the option to convert to financial rights, and asks that LIPA be given this same treatment.

13. NEPOOL and ISO-NE answer that any physical rights on the CSC as well as other non-PTF arrangements in New England do not give holders any scheduling priority on the NEPOOL PTF. They further state that scheduling priority into or out of the NEPOOL PTF system is determined by the economic merit order of the transaction under NE-SMD and that physical rights over non-PTF do not provide special scheduling rights or priority on the PTF system, as set forth in Section 25D.

14. **Commission Conclusion.** Schedule 18 of the tariff provides that a transmission customer that takes service over the CSC must also take service under the NEPOOL OATT for use of the NEPOOL PTF. The Commission agrees with NEPOOL that physical rights on the CSC do not give any special rights to the use of NEPOOL PTF facilities or the NEPOOL system itself. LIPA's rights to deliver energy to New Haven in order to reach the CSC (or conversely to get power from the CSC into New England) are the same as that of all other NEPOOL participants. LIPA is asking the Commission to grant it rights that are superior to the rights of other market participants, and we deny its request on that basis.

[14]LIPA notes that the Commission requires it to release unused transmission capacity into the secondary market. See TransÉnergie U.S. Ltd., 91 FERC ¶ 61,230 at 61,839 (2002).

15. The Commission accepted revisions to the NEPOOL tariff governing the CSC in a September 6, 2002 Order.[15] LIPA's protest regarding curtailment rights on the CSC deals with issues addressed in that proceeding. The revisions accepted in that order address curtailment, and, absent specific provisions for MTF service, are the same provisions found elsewhere in the tariff. The Commission stated that before any deviation from these provisions is permitted, the parties must make a Section 205 filing.[16] Therefore, if LIPA wishes to implement any curtailment provisions specific to MTF service, it must file them with the Commission.

16. As a related matter, under Market Rule 1, non-PTF facilities in New England would not be operated under the LMP congestion management system. Transmission service across non-PTF facilities would not be provided based on bids submitted to the ISO-NE's spot markets, but rather would be provided to those holding physical reservations.

17. Market Rule 1 and the revisions proposed by ISO-NE and NEPOOL in the instant filing presume that the CSC would be a non-PTF facility. Thus, transmission service across the CSC, like transmission service on other non-PTF facilities, would be provided to those holding physical reservations; no service would be scheduled based on bids submitted to the ISO-NE's spot markets.[17] To the extent that holders of rights on the CSC do not schedule transmission service for the full capacity of the CSC, ISO-NE would have no ability under Market Rule 1 or the ISO-NE Tariff to make the unscheduled capacity available to others. As a result, we are concerned that CSC capacity, an interface between New England and New York, could be withheld from the market, thereby allowing CSC rights' holders to exercise market power. We are also concerned that failing to apply open access principles (by not using the LMP congestion management system, including rules that would make all capacity available for use by those willing to pay the applicable market-clearing transmission usage charge[18]) to the

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[15]New England Power Pool, 100 FERC ¶ 61,259 (2002).

[16]Id. at 61,927.

[17]Currently, LIPA is the only entity with rights to use the CSC, and thus, is the only entity that could reserve and schedule transmission service across the CSC.

[18]The LMP congestion management rules would allow the holders of physical rights on the CSC to "self-schedule" transmission service across the CSC. By self-scheduling in this way, the rights holder would indicate that it wishes to be scheduled regardless of the transmission usage charge. Such a rights holder would not incur a net

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CSC facilities conflicts with the conditions under which the Commission approved TEUS's proposal for the Cross Sound Cable in our June 1, 2000 order. In that order, we stated:

> TransÉnergie commits to cooperating in the development of RTOs in the Northeast and giving operational control of the interconnector to an RTO that establishes a consistent framework for locational pricing and financial transmission rights. TransÉnergie is committed to joining an RTO that adopts such an approach to congestion pricing, i.e., one that well-defines transmission rights and incorporates locational based marginal pricing as currently prevail in the New York and PJM markets."[19]

18. TEUS has in fact turned over operational control of the CSC to NEPOOL. However, when approving the TransÉnergie proposal, the Commission specifically envisioned that an RTO would be in place by the time the CSC becomes operational and the CSC would be controlled by that RTO,[20] and that the CSC will reflect locational price differences. As stated above, we are concerned that unused CSC capacity may be withheld from the market. Because the CSC does not currently have an open access tariff on file, and the CSC as a non-PTF does not come under the NEPOOL tariff, there is no vehicle for ensuring that unscheduled capacity is made available to others. Therefore, we will direct ISO-NE to make a filing within 30 days of the date of this order that addresses our concerns.

19. **Excepted Transactions.** NEPOOL proposes to eliminate the physical scheduling of external transactions[21] (with the exception of certain Excepted

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[18](...continued)
congestion charge, however, because it would hold FTRs that would entitle the holder to congestion revenues that offset the congestion charges embodied in the transmission usage charge. However, as relevant here, any CSC capacity that is not self-scheduled by the CSC rights holder would be made available to the highest bidders.

[19]TransÉnergie U.S. Ltd., 91 FERC ¶ 61,230 at 61,840 (2000), footnote omitted.

[20]Id.

[21]An external transaction is one in which either the source or sink is not within the NEPOOL Control Area.

Transactions)[22] and schedule primarily on the basis of economic merit order. Central Vermont requests that the Commission recognize the rights of certain pre-Order No. 888 contracts over non-PTF facilities as Excepted Transactions. Central Vermont argues that the market would be best served by doing so, and thus making FTRs available across non-PTF facilities and that the proceeds from the sale of such FTRs should be allocated to the entities that are supporting the transmission and paying congestion costs on those transmission facilities. Further, Central Vermont requests the Commission to find that such Excepted Transactions for internal delivery should be exempt from congestion or new delivery charges. Central Vermont states that the pre-Order No. 888 contracts provide for physical delivery at a fixed price and thus, to maintain the rights of parties to pre-Order No. 888 contracts, the Commission should exempt pre-Order No. 888 contracts from congestion costs and other delivery costs that are created as a result of NE-SMD. PG&E raises similar issues with respect to excepted internal transactions.

20. NEPOOL and ISO-NE state in their joint answer that this issue was decided in the December 20 Order, in which the Commission considered and denied the same arguments and request made by Central Vermont and PG&E's affiliate MASSPOWER. In that Order, the Commission stated "we agree with NEPOOL and ISO-NE and National Grid that the [rights to physical delivery held harmless from congestion] that Central Vermont and MASSPOWER seek in their protests would go beyond maintaining their existing rights."[23] The Order stated that the Commission's intention is to "maintain the existing rights held by Excepted Transactions, not to expand those rights."[24] NEPOOL and ISO-NE state that, for the reasons identified by the Commission in the December 20 Order, the Commission should also reject this attempt by parties to gain new and special rights.

21. **Commission Conclusion.** We agree that we have already addressed this issue in our December 20 Order.[25] We find nothing in the current protests that warrants a

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[22]Excepted Transactions are those transmission agreements in effect on November 1, 1996 specified in Section 25 and Attachments G, G-1, and G-2 of NEPOOL's tariff. Excepted Transactions are contracts that were in force prior to Order No. 888, and that retain certain pre-Order No. 888 contract rights.

[23]December 20 at P 76.

[24]Id.

[25]"The current NEPOOL tariff defines the rights of Excepted Transactions. Under the current tariff, these customers do not have physical scheduling rights for internal

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different decision here. Central Vermont is seeking to gain new rights with regard to transactions over non-PTF facilities. As a result of the Commission's December 20 Order, PG&E has withdrawn its comments with regard to excepted internal transactions. The Commission made clear in the December 20 Order that it did not intend to further expand parties' rights, and we deny Central Vermont's request for relief on that basis.

22. **Through or Out Service.** NEPOOL and ISO-NE have decided to eliminate the pro forma system requiring advance reservations for Through or Out Service with an economic merit order scheduling and curtailment system that is more compatible with NE-SMD. Under the proposed amendments, transmission customers conducting Through or Out Service transactions over PTF will still pay for that service, but will not need to make advance reservations. According to NEPOOL, "the changes clarify that rights for transmission service are financial, not physical (with the exception of certain pre-Order 888 contracts specified in the new Attachment G-3 to the Tariff)."[26] NEPOOL states that scheduling and curtailment across the PTF interconnections to neighboring control areas will be conducted primarily on the basis of economic merit order – this system of economic scheduling has been in place for over a year for imports and is "simply being extended to Through or Out Service and applied in an LMP context."[27] Non-PTF interconnections will continue to have advance reservation requirements and physical rights associated with them as well as their own contract-specific or open access tariff arrangements. NEPOOL contends the reasons to eliminate the advanced reservations system include the elimination of the mixing physical and financial rights, more efficient use of external ties, and consistency with the Commission's SMD NOPR.

23. PG&E seeks clarification that the proposed changes "will not abrogate the bargained-for rights of existing transmission customers who are party to such Through or Out Service contracts, and that these contracts will not expire until their respective

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[25](...continued)
transactions and Excepted Transactions do not have higher priorities for scheduling internal transactions than firm service provide under the NEPOOL tariff. The requested changes would thus expand the rights that MASSPOWER and Central Vermont currently have under the currently effective NEPOOL tariff, and we will therefore not require those changes." December 20 Order at P 76.

[26]Transmittal Letter at 12.

[27]Transmittal Letter at 12.

termination dates."[28] PG&E argues that, notwithstanding the expected inception of NE-SMD, existing out service contracts should be allowed to continue until the termination date as specified in the contract, which PG&E maintains is consistent with Commission orders regarding NE-SMD's effect on existing long-term firm point-to-point transmission service reservations. PG&E states that in a November 2002 Order,[29] the Commission allowed the complainants to renew their Out Service transmission reservation priority for another year. Given the projected NE-SMD effective date of March 1, 2003, PG&E contends that Sithe Power Marketing permits holders of existing Out Service reservation priorities to continue to benefit from transmission service rights after NE-SMD takes effect. PG&E further argues that allowing these existing rights to continue beyond NE-SMD inception is in accord with the "long-held Commission principle of respecting existing contract rights."[30] PG&E states that the proposed changes are silent on the subject of these Through or Out Service contracts and suggests that the Commission should explicitly clarify that the proposed changes "are not intended to abrogate existing Through or Out Service contracts and will not do so."[31]

24. TEUS states that proposed changes to Section 20 of the NEPOOL tariff would eliminate the "higher-of" test that is currently contained in the tariff, under which the rate for Through or Out Service is the higher of (i) the PTF rate or (ii) the incremental cost of new facilities needed to provide the requested service. TEUS states that while this test is removed from the filed tariff for Through or Out Service, it remains in Section 27.5 of the tariff regarding Internal Point-to-Point Service. According to TEUS, this change will reinstate a form of prohibited "and" pricing[32] for Through or Out Service.

25. In the Joint Answer, NEPOOL and ISO-NE agree that the elimination of the Through or Out Service reservation system "is not intended to terminate any existing

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[28]PG&E Comments at 4.

[29]Sithe Power Marketing, L.P., 101 FERC ¶ 61,149 (2002) (Sithe Power Marketing).

[30]PG&E Comments at 5.

[31]PG&E Comments at 5.

[32]"And" pricing occurs when a transmission provider charges a customer both an incremental rate and an embedded cost rate for network upgrades. Xcel Energy Services, Inc., 100 FERC ¶ 61,267 at P 9 n.6 (2002).

long-term firm Through or Out Service."[33] NEPOOL and ISO-NE add that they are unaware of any "existing long-term firm Through or Out Service reservations held by PG&E or its affiliates" that would be affected by the proposal.[34] NEPOOL and ISO-NE answer the TEUS claim by stating that NEPOOL does not intend to reinstate "and" pricing, and the language in question pertains to the ability to reserve long-term firm Through or Out Service. They state that since this service will be taken and paid for on an hourly basis under the NE-SMD using bid/offers at external pricing nodes, the ability to reserve Through or Out Service is now eliminated and there is no longer a need to retain language in the tariff. NEPOOL and ISO-NE go on to state that the language was retained for Internal Point-to-Point because it is still possible to reserve this service, in advance, under the NEPOOL tariff.

26. **Commission Conclusion.** The Commission finds, for the reasons articulated in ISO-NE's and NEPOOL's response, that it should not order the relief requested by PG&E and TEUS.

27. **Allocation of Operating Reserve Charges to Resources Producing Intermittent Energy.** NEPOOL proposes to allocate Operating Reserve Charges[35] to generation units whose output deviates from their Day-Ahead schedule. CWA protests the proposed language of Manual 20 that would add provisions assessing operating reserve costs against intermittent resources for any “deviation” from the amounts cleared in the day-ahead market. As an alternative, CWA requests the Commission to consider directing NEPOOL to develop a rule that would be more reflective of the actual abilities of well-managed intermittent wind resource to forecast and schedule its output in the real-time market. NERPPA and FPL support CWA's protest.

28. NEPOOL and ISO-NE state in their answer that CWA’s concerns in this regard are misplaced. They concede that the specific language cited by CWA (taken from NEPOOL Manual 20, which is not part of the filed rate) is worded too broadly and will be deleted from NEPOOL Manual 20 by NEPOOL and ISO-NE prior to the effective date of NE-SMD.

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[33]Joint Answer at 16.

[34]Joint Answer at 16.

[35]Operating Reserve Charges are the mechanism through which NEPOOL recovers from its participants the payments it makes to resources who provide operating reserves. See Market Rule 1, Section 3.2.3.

29. **Commission Conclusion.** The Commission finds that CWA's concerns will be resolved by the deletion of the inappropriate language by NEPOOL/ISO-NE.

30. **Maximum Generation Emergencies.** Market Rule 1 allowed Participants to designate a specific level of output between the Economic Maximum Limit and the Emergency Maximum Limit that could be called upon by ISO-NE when a Maximum Generation Emergency was declared.[36] During a Maximum Generation Emergency, a particular unit would be called upon by ISO-NE to deliver that increment in order to maintain Operating Reserve requirements. If a Maximum Generation Emergency were declared, the highest accepted real-time offer price would set the real-time price (either within the NEPOOL control area or within the sub-region, depending on where the Emergency was declared), and all energy would be sold at that price. These provisions were originally proposed by ISO-NE out of a concern that the additional capacity available to the market during a Maximum Generation Emergency declaration would drive prices down, thus distorting scarcity pricing.

31. Discussions with stakeholders led ISO-NE to conclude that a superior approach was "to expect Participants to price these emergency blocks of capacity at the appropriate level so that scarcity pricing will be achieved through normal operation of the bid-based LMP system."[37] Specifically, NEPOOL and ISO-NE's proposal allows resources to "submit these higher bid-blocks, formally reserved only for use in Maximum Generation Emergencies, into the Energy Markets for normal dispatch by the ISO."[38] This new approach would eliminate the potential to impose NEPOOL-wide prices that may not accurately reflect local conditions, demand or prices. NEPOOL and ISO-NE propose the elimination of Section 2.5(d) of Market Rule 1 in its entirety, and that the terms "Maximum Generation Emergency" and "Emergency Maximum Limit" be deleted from the list of defined terms. The term "Emergency Condition" would be inserted into that list, replacing "Maximum Generation Emergency" at various places within Market Rule 1.[39] NEPOOL and ISO-NE add that ISO-NE will work with the market advisor and

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[36]This difference represented an increment of energy a unit was capable of delivering for a period of time without exceeding specified limits of equipment stress and operating permits.

[37]Transmittal Letter at 8.

[38]Joint Answer at 5.

[39]An "Emergency Condition" is an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load,
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participants to craft further revisions to ensure that reserve-shortage conditions are efficiently reflected in locational prices.

32. Exelon does not oppose the removal of the Maximum Generation Emergency mechanism but, as explained below, argues that the Commission should retain provisions that will promote efficient pricing during capacity deficiencies.

33. Exelon states that under the current rules the Maximum Generation Emergency is a methodology that allows ISO-NE to use a resource's emergency generation capacity under specific circumstances, i.e. when it calls a Maximum Generation Emergency under Action 1 of OP4.[40] This capacity runs at higher than usual levels, which burden the unit with additional stress, risk of failure and maintenance costs. Under the old rules, these upper increments were set aside and specially priced. However, Exelon argues that the removal of the Maximum Generation Emergency concept from Market Rule 1 should not result in the elimination of the associated capacity deficiency pricing provisions contained in Section 2.5(d). Exelon states that although the frequency of capacity deficiencies may decrease with the elimination of the Maximum Generation Emergency, Capacity Deficiencies (which is to say, an inability to satisfy Operating and Replacement Reserve Requirements) will continue to occur, and that without Section 2.5(d) in place, prices are less likely to reach efficient levels when ISO-NE cannot meet Operating and Replacement Reserve Requirements.

34. Exelon argues that removing Section 2.5(d) from Market Rule 1 would leave nothing in the market rules to send price signals during time of capacity deficiencies for two reasons: (1) ISO-NE's price-setting software does not consider capacity deficiencies when calculating prices; and (2) as accepted by the Commission, NE-SMD removed the scarcity pricing reforms introduced by ISO-NE's independent market advisor Dr. David Patton in 2001. Absent such provisions, Exelon argues that market prices are less likely

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[39](...continued)
equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of emergency procedures as defined in the NEPOOL Manuals.

[40]On page 5 n. 7 of the Joint Answer ISO-NE and NEPOOL agree that "a Maximum Generation Emergency would have essentially used the same capacity deficiency trigger (i.e., declaration of OP4 events)."

to reach efficient levels when ISO-NE cannot satisfy its Operating and Replacement Reserve Requirements. Moreover, Exelon argues that NEPOOL has a history of pricing problems during scarcity periods, which the Commission acknowledged and responded to with the aforementioned scarcity pricing reforms. Exelon asserts that if the Commission accepts the proposed changes, all such improvements will be lost.

35. Exelon believes that removing provisions to account for scarcity pricing during Capacity Deficiencies is imprudent and thus Section 2.5(d) should be retained while NEPOOL works on new rules. Exelon proposes to remove “Maximum Generation Emergency” references in Section 2.5(d) and replace those with “Operating Procedure 4 Conditions.” This is possible, Exelon explains, as the trigger for Maximum Generation Emergency and OP4 Conditions are essentially the same. This would, Exelon argues, provide some other trigger to ensure scarcity pricing during periods of Capacity Deficiency, while allowing efficient pricing during Capacity Deficiencies.

36. In their joint answer ISO-NE and NEPOOL argue that Exelon's request is "contrary to the entire purpose of the proposed change to Section 2.5(d) . . . which was to allow scarcity pricing to be reflected though normal operation of the bid-based LMP system."[41] ISO-NE and NEPOOL reiterate that the filed changes permit participants to price the higher blocks of their units at levels reflecting scarcity at particular locations and that they expect that participants will price these higher bid blocks "consistent with the increased cost and risk associated with the principles and operations of a competitive market."[42] ISO-NE and NEPOOL assert that Exelon's proposal would move away from LMP and would re-introduce region-wide clearing prices during OP 4 conditions. Concerning the scarcity pricing reforms, ISO-NE and NEPOOL state that Exelon is correct that these will not be replicated for the initial SMD roll-out, but they maintain that they are committed to the re-introduction of the scarcity pricing reforms as soon as possible.

37. **Commission Conclusion.** The Commission agrees with ISO-NE and NEPOOL with regard to Section 2.5(d). We agree that it is reasonable to remove the rule that would automatically raise the Real-Time prices of all nodes to the level of the highest priced node during a Maximum Generation Emergency. Because of transmission constraints, it may be appropriate for the prices at some nodes to be lower than at others, even during Maximum Generation Emergencies. As to the scarcity pricing reforms, we ruled in the September 20 Order that the Commission initially accepted those reforms to

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[41]Joint Answer at 5.

[42]Joint Answer at 6.

allow for a more accurate indication of the value of generation.[43] It is our view that the changes proposed by Exelon would not allow for as accurate an assessment of the value of a particular unit's generation as ISO-NE and NEPOOL's proposal. Moreover, as indicated in the September 20 Order, ISO-NE and NEPOOL are committed to re-introducing the scarcity pricing reforms, and we urge all parties to work through stakeholder processes to achieve that result. We deny the relief requested by Exelon.

38. **Payment of Operating Reserve Credits to Self-Scheduled Units**. For each Operating Day, the ISO calculates the Operating Reserve Credit due each Participant for pool-scheduled generating Resources.[44] However, if there are any Self-Scheduled hours contained within a Pool-Scheduled Resource's contiguous block of scheduled hours that Pool-Scheduled Resource is not eligible to receive Operating Reserve Credits for that block of scheduled hours. The credit payments are designed to ensure that these pool-scheduled resources receive at least their as-bid costs. NEPOOL does not permit the payment of Operating Reserve Credits to resources that are self-scheduled (i.e., that choose on their own when to start up and run, rather than being scheduled by NEPOOL) within a day, or to resources that are partly self-scheduled and partly pool-scheduled within a day.[45] NEPOOL states that while there was little disagreement that a self-scheduled resource should not be able to recover Operating Reserves Credits, some participants supported giving Operating Reserves Credits when resources are both self and pool-scheduled within an operating day. NEPOOL, however, believes that in order to ensure resources are paid appropriately, this flexibility necessitates additional restrictions on the receipt of Operating Reserves Credits. Appendix F incorporates the Operating Reserve accounting details from NEPOOL Manual 28 into Market Rule 1, in

[43]September 20 Order at P 75.

[44]To determine Operating Reserve Credits, NEPOOL compares a resource's total offer amount for generation, including Start-Up Fee and No-Load Fee as applicable, to that resource's total energy market value during the day. If the total value is less than the offer amount, the difference is credited to the Participant. See Market Rule 1, Section 3.2.3.

[45]NEPOOL has added new sections (f), (g) and (h) to Section 1.10.2 of Market Rule 1, clarifying when Operating Reserves Credits are payable to resources. Appendix A to the transmittal letter asserts that the NEPOOL provisions for Operating Reserves Credits differ from those in PJM, as Market Rule 1 affords resources greater flexibility than those in PJM. NEPOOL further states that its provisions deviate from those in PJM in a manner that facilitates markets, stating that "[i]n PJM, no Self-Scheduled Resources receive Operating Reserve Credits."

explaining the details of eligibility limitations on the receipt of Operating Reserve Credits for units that choose to combine self-scheduling and pool-scheduling. NEPOOL asserts that these provisions appropriately: "(i) reflect that a unit that Self-Schedules is required to operate for its minimum run time, and (ii) attribute responsibility for Start-Up and No-Load costs to a unit that is on line and operating as a result of its own Self-Schedule(s)."[46]

39. Exelon states that NEPOOL's proposal to disqualify a unit from receiving Operating Reserve Credits in all hours and for all of its output if that unit partially self-schedules is illogical, may incent undesirable behavior and should be eliminated. Exelon argues that recovery of the "as bid" costs for pool-scheduled resources is a bedrock rule of power markets. Exelon advocates that units should not be denied Operating Reserve Credits for those MWs that are not self-scheduled. Exelon asserts that in the NEPOOL Markets Committee, ISO-NE staff stated that this issue existed in PJM and that ISO-NE inherited it as a result of the purchase of the PJM software. Exelon asserts that it is a PJM participant and it does not believe that this issue is a problem in PJM. Exelon supports allowing ISO-NE time to modify the software within a reasonable time, while moving forward on the implementation of SMD.

40. In their joint answer, ISO-NE and NEPOOL state that existing market rules as well as those in the proposed SMD guarantee that pool-scheduled Resources will at least receive their as-bid costs, unless they are being mitigated. ISO-NE and NEPOOL further assert that NE-SMD will give resources flexibility not available in PJM: unlike PJM, NE-SMD will allow self-scheduled resources to offer increments of energy for pool scheduling above their self-scheduled level of output, or for periods following their self-schedule within the operating day. ISO-NE and NEPOOL assert that participants are afforded the option of self-scheduling and pool-scheduling within the same day "with the reasonable condition that such Self-Scheduled Resources accept the market result without the administrative guarantee of receiving at least their as-bid costs."[47] ISO-NE and NEPOOL state that software and process limitations necessitate the Operating Reserve eligibility limitations currently contained within Appendix F. However, they state that they expect to revisit the issue of what costs are appropriately guaranteed to resources that co-mingle self and pool-schedules within an operating day, and under what circumstances some form of Operating Reserve Credits should be awarded, the debate on this subject is incomplete, and that both will consider further and investigate what is desirable and appropriate with regard to flexibility for self-scheduled resources.

[46]Section 3 of Appendix A to Transmittal Letter.

[47]Joint Answer at 8.

41. **Commission Conclusion.** The Commission finds that, for resources electing to self schedule and pool schedule in the same commitment period during the same operating day, such resources should not be guaranteed the receipt of their as-bid costs during the pool scheduled portion. A resource electing to self-schedule does not have to disclose the terms of its transactions to ISO-NE. In cases where a resource is partly self scheduled and partly pool scheduled, ISO-NE cannot properly assess that resource's operating day profit or loss and thus cannot verify whether it has met its costs for the operating day. Allocating Operating Reserve Credits to resources that co-mingle self and pool scheduled resources runs the risk of paying a resource in excess of its as-bid costs for an operating day. For that reason the Commission accepts the proposed changes. The Commission notes that these will allow resources the option of self-scheduling and pool-scheduling within the same day. The Commission will not require ISO-NE and NEPOOL to modify the software to guarantee that partially self-scheduled participants receive as-bid costs for the pool-scheduled increments of their output. The Commission notes that ISO-NE and NEPOOL have committed to further examination of the issue, and thus directs ISO-NE and/or NEPOOL to report the progress of the analysis in the progress reports ordered in Ordering Paragraph D of the September 20th order.

42. **Dispatch of Special Constraint Resources by Local Control Areas**. The proposed NEPOOL tariff amendments also include a new Schedule 19 (Special Constraint Resource Service), which is designed to address the situation in which a transmission owner or distribution company – either on its own or through a local or "satellite" control center – asks ISO-NE to change the commitment or incremental loading of a generation resource. ISO-NE and NEPOOL indicate that ISO-NE does not have the capability to monitor certain constraints that are typically related to "local" transmission or non-PTF. In the instances when a transmission owner or distribution company asks ISO-NE to take such actions to maintain local system reliability, ISO-NE is authorized to accept the analysis of the satellite and to implement the request. ISO-NE and NEPOOL state that the decision of the satellite is subject to review/audit. As proposed, the new Schedule 19 would allocate the costs associated with a resource designated as a Special Constraint Resource to the Transmission Owner or distribution company making the request.[48] ISO-NE and NEPOOL argue that this approach assures

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[48]ISO-NE and NEPOOL indicate that "the costs are those to change the commitment of a generating resource or the incremental loading on a previously committed generating resource to provide relief for constraints (thermal, voltage or stability) which costs are not reflected in the ISO's systems and operating procedures." (Transmittal Letter at 15).

(continued...)

that those customers making these requests actually pay the costs, providing incentive to make distribution or system improvements to avoid the charges in the future.

43. The changes will allow local resources dispatched by local control centers to set clearing prices when dispatched in merit as well as allow for the allocation of costs thereof directly to the local control center. Exelon contends that the newly proposed rules lack clarity. It asks the Commission to confirm that a Special Constraint Resource is only eligible to set the nodal or clearing price if ISO-NE's pricing algorithm would have otherwise economically dispatched the unit.

44. Exelon further argues that the filing as proposed does not attempt to rectify the "ineffectiveness" of ISO-NE's monitoring and auditing with regard to local control center dispatch requests. While ISO-NE retains the right to audit under Operating Procedure 1, Exelon asserts that past oversight "appears to have been very limited." Exelon maintains that this problem is not unique to New England and points to PJM's solution as a model for ISO-NE. As described by Exelon, the PJM rule: (1) specifically sets out when and how a local control center can make reliability-related dispatch requests; (2) provides that as a consequence of making such a request, the distribution company must allow PJM to monitor the transmission constraint; and (3) provides that "PJM will retain control over the local transmission area for at least 90 days after the local dispatch request is made."[49]

45. Further, Exelon asserts that ISO-NE's rule allows for local dispatch to rectify both distribution-related and transmission-related reliability problems, and states that ISO-NE should emulate PJM's rule, which provides that local control centers can only request dispatch of a resource for transmission-related local reliability purposes.

46. In the Joint Answer, ISO-NE and NEPOOL confirm Exelon's interpretation that a Special Constraint Resource dispatched by the local control center will be allowed to set the nodal or clearing price "if it would have been dispatched economically by ISO-NE absent local control center dispatch."[50]

47. With regard to monitoring and auditing of local control center dispatch requests, however, NEPOOL's and ISO-NE's joint answer disagrees with Exelon's characterization

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[48](...continued)

[49]Exelon Comments at 4.

[50]Joint Answer at 10.

of the control centers and/or satellites. ISO-NE argues that it "has all the necessary and appropriate authority to oversee the Satellites and had properly extended that authority." The joint answer further argues that Exelon has provided no evidence that its monitoring has been ineffective, and therefore there is no basis to presume that ISO-NE's authority will be ineffective going forward.

48. With regard to the question of dispatching local resources to address both transmission-related and distribution-related reliability problems, ISO-NE and NEPOOL argue that, on the basis of its November 22 filing, the costs of dispatching Special Constraint Resources will always be allocated to the utility requesting service. Moreover, the Joint Answer contends, every investor-owned utility in New England, save Vermont, has divested its generation resources. Thus, according to NEPOOL and ISO-NE, distribution companies have little choice but to rely on resources controlled by ISO-NE when distribution-related reliability problems must be resolved by generation resources.

49. **Commission Conclusion.** The Commission will not require ISO-NE to modify its proposal with regard to the monitoring and auditing provisions sought by Exelon. The Commission agrees with NEPOOL and ISO-NE and finds that Exelon failed to provide evidence of the ineffectiveness of current ISO-NE rules governing monitoring and auditing. Nonetheless, the Commission recognizes Exelon's desire for robust monitoring and auditing of local dispatch requests and notes that ISO-NE reserves the right to review and audit those individual requests. The Commission further encourages Exelon and other parties to pursue this question through NEPOOL stakeholder process, including, when and how a local control center can make reliability-related dispatch request. Finally, on the basis of the explanation provided by NEPOOL and ISO-NE, the Commission views as appropriate the dispatch of resources by local control centers for either distribution-related or transmission-related reliability needs.

50. **Manuals**. NEPOOL notes that it has completed all the NEPOOL Manuals and posted them on its web site, including the provisions of certain manuals which it has included in Market Rule 1. NECPUC and VDPS request that the Commission make clear that acceptance of NEPOOL’s proposal to include certain portions of the NEPOOL Manuals in the Market Rules at this time is not intended to preclude future arguments that other portions of the Manuals should also be included in the Market Rules. NECPUC and VDPS state that such a clarification is needed for two reasons. First, the NEPOOL Manuals are voluminous, and provisions that at first did not appear necessary to file might, with experience, prove to affect substantially the rates, terms and conditions of service. Second, future modifications to the unfiled portions of the NEPOOL Manuals might change their impact such that they should be filed with the Commission.

51. DENA is concerned by ISO-NE and NEPOOL's failure to include provisions in either Market Rule 1 or Manual 28 that address the manner in which transmission losses will be calculated. DENA notes that ISO-NE is preparing a "white paper" on the loss calculation methodology and asserts that this information should be fully vetted, and documented in Manual 28 and ultimately in Market Rule 1. DENA states that market participants will be charged for losses and therefore the loss calculation methodology may fairly be said to affect rates, terms and conditions of service. In addition, DENA has requested that Manual 6 be modified so that an entity that is eligible for an award of Qualified Upgrade Awards (QUAs)[51] may know the megawatt value of the upgrades that ISO-NE intends to use in the QUA calculations. DENA request the Commission order ISO-NE to clarify that the requirement to provide this information be contained in Manual 6 and, to the extent that such provisions affect rates, terms and conditions of service, to file such provisions as part of Market Rule 1.

52. In their joint answer, NEPOOL and ISO-NE agree with NECPUC and VDPS and state that it was not ISO-NE's intent to preclude further arguments that other portions of the NEPOOL manuals should be filed with the Commission. Addressing DENA's concerns, the joint answer also commits to document and place on the ISO-NE website details, including a formula, regarding the manner in which marginal losses will be calculated. With respect to DENA's concerns with Manual 6, the joint answer notes that DENA has raised similar issues in the past. The Commission's September 20 Order and December 20 Order grant DENA's earlier protests and ISO-NE commits to calculating QUAs in compliance with the Commission's orders. ISO-NE and NEPOOL explain that their software will calculate awards of ARRs associated with the increased transfer capability created by a transmission upgrade. Specifically, the software will calculate for each FTR auction the ARR awards based on the incremental MW values created on each individual transmission facility as reflected in the network model used for the FTR auction. ISO-NE and NEPOOL also state they intend to review Manual 6 to determine if further clarification is needed to explain the calculation process in more detail.

53. **<u>Commission Conclusion.</u>** NEPOOL and ISO-NE were required to address similar concerns in the September 20 Order and December 20 Order. We expect NEPOOL and ISO-NE to continue to review and modify the NEPOOL Manuals as necessary and to file with the Commission those items that affect rates, terms and conditions of service as they are identified. The Commission's September 20 Order specifically requires that "ISO-NE be transparent in all of its calculations, procedures,

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[51]QUAs are awarded for transmission upgrades that increase the transfer capability of the NEPOOL transmission system.

and review processes."[52] Thus, the Commission finds that Manual 28 should reflect the methodology by which losses are calculated and Manual 6 should reflect the methodology by which the software will determine the megawatt value of the upgrades which will be eligible for QUAs. Further, to the extent that such calculations affect rates, terms and conditions of service, they must be filed with the Commission.

CONCLUSION

54. We accept the filing, with the additional requirements as discussed above.

The Commission orders:

(A) The filing is hereby accepted.

(B) ISO-NE and/or NEPOOL are hereby directed to report the progress of their analysis of issues relating to the ability of partially Self-Scheduled participants to receive as-bid costs for the Pool-Scheduled increments of their output in the progress reports ordered in Ordering Paragraph D of the September 20 Order.

(C) ISO-NE is hereby directed to make a filing, within 30 days of the date of this order, to address provisions governing the use of unscheduled capacity on the CSC.

(D) NEPOOL is hereby directed to make a filing, within 30 days of the date of this order, to add provisions to either Section 25D or Schedule 18 of the NEPOOL Tariff that specifically state that neither FTRs nor congestion costs will be assigned to the CSC as long as it remains classified as non-PTF.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

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[52] September 20 Order at para 84.