UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

Midwest Independent Transmission System Operator, Inc. — Docket No. ER04-691-003

Public Utilities with Grandfathered Agreements in the Midwest ISO Region — Docket No. EL04-104-003

ORDER ON REHEARING

(Issued November 8, 2004)

Section — Paragraph Number

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1. In an order dated August 6, 2004, the Commission conditionally accepted the Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) proposed Transmission and Energy Markets Tariff (TEMT), which, when implemented, will allow the Midwest ISO to initiate Day 2 operations in its 15-state region.[1] The Midwest ISO's Day 2 operations will include, among other things, day-ahead and real-time energy markets, and a Financial Transmission Rights (FTR) market for transmission capacity. These markets incorporate the major features used successfully in PJM Interconnection, L.L.C. (PJM), New York Independent System Operator, Inc. (NYISO) and ISO New England (ISO-NE).

[1] *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 (2004) (TEMT II Order). The TEMT contemplates that all services provided pursuant to its terms and conditions will be provided by a Transmission Provider. In turn, the TEMT defines "Transmission Provider" as the Midwest ISO or any successor organization. *See* Module A, section 1.320, Original Sheet No. 133. For clarity, we will refer to the Midwest ISO wherever the TEMT refers to the Transmission Provider.

2. Today's order addresses all issues raised on rehearing of the TEMT II Order, except for the issue of data confidentiality.[2] On most major issues, including market start-up safeguards, application of marginal losses, mitigation, the resource adequacy plan and the System Supply Resource (SSR) program, except in limited instances, we deny rehearing and reaffirm our TEMT II Order. We grant the Independent Market Monitor's (IMM) request to postpone the establishment of Automatic Mitigation Procedures (AMP), provide various clarifications and respond to several procedural motions. We also grant rehearing and clarification with regard to certain issues raised regarding FTR allocations. Our order benefits customers because it provides further guidance and clarification to the Midwest ISO and its stakeholders prior to the March 1, 2005 start of the Day 2 energy markets.

I. Introduction

3. On rehearing of our TEMT II Order, a number of parties contend that the market is not ready to start, the safeguards provide inadequate protection, the transitional mechanisms are unfair and the market rules need to be revised. We recognize the challenges of the enterprise; they are not insurmountable, however. Our goal is to place the TEMT in effect in a timely, reliable and efficient manner, so that customers can receive the benefits of the Midwest ISO's centrally dispatched markets.[3] To this end, we have ordered safeguards and approved market rules consistent with practices in the other centrally dispatched markets and, except in limited instances, we generally reaffirm those findings here.

4. Both we and the Midwest ISO have stated that the Day 2 market will not start unless it is ready from the standpoints of reliability, other aspects of system operations, and market operations. Given that the Midwest ISO did not have prior experience operating as a single power pool and has had only a short period of experience operating under a single reliability framework, we ordered it to implement several safeguards and other protections at start-up for a transition period. We also required the Midwest ISO and its IMM to make several other compliance filings to update us and market

[2] This issue will be deferred pending further filings, and addressed in a future Commission order. *See Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,321 (2004) (Confidentiality Order).

[3] The Commission has found that the Day 2 energy markets will be more efficient and reliable than the status quo Day 1 market, even though transactions under certain agreements will not take place under the TEMT. *See Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,236 at P 89, 100 (2004).

participants of their market readiness. In this regard, we required the Midwest ISO to certify its readiness to commence its energy markets prior to their start. The transitional market safeguards are intended to give the Midwest ISO sufficient experience with its market and system operations to allow it to detect and correct initial problems, and to afford market participants experience with the market prior to increased exposure to price uncertainties due to, for example, congestion and loss charges.

5. With these goals in mind, we believe we have made the right decisions for attaining a timely, reliable and efficient market start, and generally deny rehearing on the issues raised regarding inadequate protections, unfair transitional mechanisms and revisions to market rules. We believe that the Midwest ISO and market participants need certainty as to the market rules that will be in place at the start of the market so the Midwest ISO can administer the market and participants can hedge their transactions, based on known rules. We reiterate to the parties that our orders have begun the process of opening the way for the Midwest ISO to initiate energy markets, increasing both system reliability and competition in the Midwest ISO region.

II. Background

6. By order issued September 16, 1998, the Commission conditionally approved the formation of the Midwest ISO.[4] The Formation Order also conditionally accepted for filing an open access transmission tariff (OATT) for the Midwest ISO, and an Agreement of Transmission Facilities Owners to Organize the Midwest Transmission System Operator, Inc. (Midwest ISO Agreement), and established hearing procedures. In addition, the Commission granted conditional approval for ten public utilities to transfer operational control of their jurisdictional transmission facilities to the Midwest ISO.[5]

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[4] *Midwest Independent Transmission System Operator, Inc.*, *et al.*, 84 FERC ¶ 61,231 (Formation Order), *order on reconsideration* 85 FERC ¶ 61,250, *order on reh'g*, 85 FERC ¶ 61,372 (1998).

[5] Formation Order at 62,167, 62,169-70. *See also* Midwest ISO Agreement at Appendix C.II.A.1.f.

7. On December 20, 2001, the Commission found that the Midwest ISO's proposal to become a Regional Transmission Organization (RTO) satisfied the requirements of Order No. 2000,[6] and thus granted the Midwest ISO RTO status.[7] The Commission also determined that the Midwest ISO's proposal for congestion management was a reasonable initial approach to managing congestion that satisfied the requirements of Order No. 2000 for Day 1 operation of an RTO. It directed the Midwest ISO to develop a market-based approach to managing congestion to satisfy the requirements for Day 2 operations under Order No. 2000.

8. Subsequently, the Midwest ISO filed a petition for declaratory order – the culmination of over a year of stakeholder discussions[8] – that sought the Commission's endorsement of the general approach represented in three proposed market rules (Market Rules). The Market Rules proposed in the filing would provide for: (1) a security-constrained, centralized bid-based scheduling and dispatch system (*i.e.*, day-ahead and real-time market rules); (2) FTRs for hedging congestion costs; and (3) market settlement rules. The Commission approved the general direction of the Midwest ISO's proposals, reserving judgment on some issues and providing guidance on others.[9] The Commission affirmed many of its conclusions on rehearing.[10]

9. On July 25, 2003, the Midwest ISO filed a proposed TEMT pursuant to section 205 of the Federal Power Act (FPA) (July 25 Filing). The July 25 Filing included terms and conditions necessary to implement a Day-Ahead Energy Market, Real-Time Energy Market, and FTRs. The July 25 Filing met with numerous protests, many of

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[6] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (2000), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Feb. 25, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd*, *Public Utility District No. 1 of Snohomish County*, *Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[7] *Midwest Independent Transmission System Operator, Inc.*, 97 FERC ¶ 61,326 (2001), *reh'g denied* 103 FERC ¶ 61,169 (2003).

[8] *See* Doying testimony at 4 (March 31, 2004).

[9] *Midwest Independent Transmission System Operator, Inc.*, 102 FERC ¶ 61,196 (2003) (Declaratory Order).

[10] *Midwest Independent Transmission System Operator, Inc.*, 103 FERC ¶ 61,210 (2003).

which alleged that the filing was incomplete and premature. Following a stakeholder vote, the Midwest ISO filed a motion to withdraw the filing, but it requested "any and all guidance the Commission can give the Midwest ISO and its stakeholders on the matters presented in the July 25th Filing."[11]

10. The Commission granted the Midwest ISO's motion to withdraw the July 25 Filing and provided, on an advisory basis, guidance on a number of issues raised in that filing.[12] The Commission stated in the TEMT I Order that it expected its guidance to better enable the Midwest ISO to prepare and file a complete version of the TEMT or a similar proposal. The Commission instructed the Midwest ISO to include five elements in its revised Energy Markets filing: (1) a *pro forma* System Support Resource Agreement; (2) a marginal loss crediting mechanism; (3) a methodology for initial FTR allocations; (4) creditworthiness provisions; and (5) market power mitigation measures.

11. The Midwest ISO filed a revised TEMT on March 31, 2004 (March 31 Filing), raising an issue that will be important to the operation of the proposed energy markets. The Midwest ISO stated in its transmittal letter, and through the testimony of two witnesses, that it would be unable to operate its Energy Markets without integrating an estimated 300 pre-OATT grandfathered agreements (GFAs) that are currently effective in the Midwest ISO region. It also concluded that up to 40,000 megawatts of transmission service – about 40 percent of total load in the region[13] – was likely to be associated with the GFAs.[14] The Midwest ISO argued that allowing holders of GFAs scheduling rights

[11] Motion of the Midwest Independent Transmission System Operator, Inc., to Withdraw Without Prejudice the July 25, 2003 Energy Markets Tariff Filing at 5, Docket No. ER03-1118-000 (Oct. 17, 2003).

[12] *Midwest Independent Transmission System Operator, Inc.*, 105 FERC ¶ 61,145 (2003) (TEMT I Order), *reh'g dismissed*, 105 FERC ¶ 61,272 (2003).

[13] The Midwest ISO stated that, after reviewing all of the contracts listed in Attachment P of the OATT, the specific details of the contracts, such as usage, scheduling requirements and megawatt quantity or capacity, were not readily apparent on the face of some of the contracts. The Midwest ISO added, however, that about half the contracts had a specific megawatt value associated with them, and that in the aggregate those contracts accounted for approximately 20,000 megawatts of capacity. The Midwest ISO projected that the remaining half of the GFAs were likely to be associated with a similar number of megawatts.

[14] The Midwest ISO's analysis assumed a peak capacity of 97,000 megawatts. *See* McNamara testimony at 84 n.5 (March 31, 2004).

similar to their current practice would require a physical reservation, or carve-out, of transmission capacity in the day-ahead energy market and until the scheduling deadline prior to real-time dispatch. It stated that this "cannot be accomplished without negatively impacting the Midwest ISO's ability to reliably operate the Energy Markets and without placing excessive financial burden on other Market Participants."[15]

12. On May 26, 2004, the Commission issued a procedural order that provided an initial response to the threshold GFA issue.[16] The Commission explained that "the development of the Midwest ISO as an RTO has reached a point at which the Commission must examine the potential conflict between our desire to preserve the GFAs and our instructions that the Midwest ISO should develop a market-based system of congestion management."[17] The Commission identified a need for further information about the GFAs and a desire to better understand how the GFAs and the proposed Energy Markets would affect one another. Accordingly, the Commission initiated an investigation, under section 206 of the FPA, of the GFAs "to decide whether GFA operations can be coordinated with energy market operations, whether and to what extent the [Transmission Owners] should bear the costs of taking service to fulfill the existing contracts and whether and to what extent the GFAs should be modified."[18]

13. The Commission issued two orders addressing the merits of the March 31 Filing. The first of these orders – the TEMT II Order, issued August 6, 2004 – conditionally accepted the Midwest ISO's TEMT proposal. More specifically, the Commission accepted and suspended the proposed TEMT and permitted it to become effective

[15] Midwest ISO Transmittal Letter at 9, Docket No. ER04-691-000 (March 31, 2004).

[16] *Midwest Independent Transmission System Operator, Inc.*, 107 FERC ¶ 61,191 (2004), *reh'g pending* (Procedural Order).

[17] Procedural Order at P 65. *See also* Declaratory Order at P 29-32, 64 ("We continue to believe that customers under existing contracts, both real or implicit, should continue to receive the same level and quality of service under a standard market design."); Declaratory Order Rehearing at P 27-31; *cf.* TEMT I Order at P 22 (encouraging the Midwest ISO to resubmit its Energy Markets proposal).

[18] Procedural Order at P 67.

March 1, 2005, subject to conditions and further orders on GFAs and Schedules 16 and 17 of the Midwest ISO Tariff.[19] The Commission also accepted certain tariff sheets to be effective on August 6, 2004, subject to conditions and further order on GFAs. In order to address the Midwest ISO's unique features, such as the fact that it does not have prior experience operating as a single power pool and has only a short period of experience operating under a single reliability framework, the Commission ordered the Midwest ISO to implement additional safeguards to ensure additional protections for wholesale customers during start-up and transition to fully-functioning Day 2 energy markets in 2005.

14. On September 15, 2004, the Commission issued the second order, which concluded its investigation of the GFAs and addressed how the GFAs should be treated in the Midwest ISO's energy markets.[20] The GFA Order divided the GFAs into several categories, with differing consequences for their treatment. Among other things, the GFA Order required the Midwest ISO to carve some of the GFAs out of its markets and accepted the tariff sheets that described the prospective treatment of GFAs.

III. Requests for Rehearing and Clarification

15. Parties filed a total of 30 requests for rehearing and clarification of the TEMT II Order, as listed in Appendix A.[21] The requests for rehearing address, among others, the following issues: (1) the bifurcated procedure the Commission has used to consider the TEMT and the GFAs; (2) market readiness; (3) transitional measures and market start-up safeguards, including cost-based bidding and whether the congestion cost hedge approved for Narrow Constrained Areas (NCAs) grants too much protection, or not enough protection; (4) details of the FTR allocation process, including issues related to

[19] Schedule 16 provides for a deferral of costs related to the development and implementation of the system and processes required to administer FTRs and the recovery of those deferred costs and the costs related to the ongoing administration of FTRs. Schedule 17 provides for a deferral of start-up costs related to the establishment of energy markets and recovery of such deferred costs and the ongoing costs of providing energy markets service once the markets are operational.

[20] *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,236 (2004) (GFA Order).

[21] Acronyms and short forms used for party names throughout the order can be found in Appendix A. As described below, the IMM, a non-party to this case, also filed a request for clarification.

priority therein; and (5) whether it is feasible or practical for the Midwest ISO to initiate its markets without seams agreements in place. We will describe and address the issues raised in the rehearing requests in greater detail below.

IV. Discussion

A. Procedural Issues

1. Disposition of Filings

a. Motions to Intervene Out of Time

16. In its request for rehearing, Illinois Power asks the Commission to clarify that it has granted Illinois Power's motion to intervene in Docket No. ER04-691-000. Illinois Power notes that it filed a motion to intervene out of time in this docket on June 7, 2004, before the TEMT II Order was issued, and addressed the motion to the Commission rather than the Administrative Law Judges (ALJs) presiding in the Step 1 hearing on GFA issues. Illinois Power states that it believes that the Commission has not acted on its motion to intervene.

17. The South Dakota Public Utilities Commission (South Dakota Commission) filed a motion for leave to intervene out of time on September 15, 2004, after the TEMT II Order was issued. The South Dakota Commission seeks to intervene out of time in order to support Montana-Dakota and Otter Tail. It states that those utilities have spent considerable time explaining why the TEMT cannot be rationally applied to their respective systems as matters now exist, and that both have brought forth an interim solution that the South Dakota Commission believes will fit all parties' needs, but that the utilities have been ignored. The South Dakota Commission argues that negative effects of the Day 2 markets will be borne by its jurisdictional customers, and that the Midwest ISO should assure that Montana-Dakota and Otter Tail will be held harmless until all material issues can be resolved. If the Midwest ISO cannot agree to hold these utilities harmless or grant waiver of their participation in the market, or is otherwise unable to address these issues, the South Dakota Commission argues that the best resolution may be the withdrawal of its jurisdictional utilities from the Midwest ISO.

18. We will grant Illinois Power's request for clarification and will grant its motion to intervene. We will also grant the June 7, 2004 motion to intervene of the Large Public Power Council, which was filed before the TEMT II Order was issued, which was not ruled upon earlier. Finally, we will grant the South Dakota Commission's motion to intervene out of time. It is Commission policy that parties seeking intervention after

issuance of a dispositive order bear a higher burden to show good cause to support their late intervention.[22] We will grant the South Dakota Commission's unopposed motion because, as a state commission, it has a unique interest in this proceeding involving, as it does, the restructuring of electric transmission service and electric energy markets in South Dakota, that no other party can adequately represent.

b. Other Filings

19. The IMM filed a request for rehearing and clarification on September 7, 2004, but later sought to withdraw that filing. On September 13, 2004, it filed a request for clarification of the TEMT II Order. Midwest TDUs and Coalition MTC filed an answer to the IMM's request for clarification. Madison Gas and Electric Company and WPPI filed a response to WEPCO's request for clarification. Montana-Dakota amended its request for rehearing on September 28, 2004.

20. The IMM has not filed the motion to intervene that is necessary, under the Commission's Rules of Practice and Procedure, to become a party to a proceeding.[23] The FPA requires that applicants for rehearing be parties to the proceeding in which they seek rehearing, so the IMM's September 7 request for rehearing is impermissible.[24] We will therefore grant the IMM's request to withdraw its request for rehearing. We will, however, clarify our prior ruling and the rationale for that ruling, for the benefit of the Midwest ISO and the participants in the energy markets.

21. The Commission's Rules of Practice and Procedure prohibit answers to requests for rehearing.[25] Commission precedent, moreover, disallows supplements to requests for rehearing where the supplement is filed beyond the 30-day filing deadline.[26] Accordingly, we will reject the responses of Midwest TDUs and Coalition MTC and of Madison Gas and Electric Company and WPPI. We will also reject Montana-Dakota's amendment to its request for rehearing.

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[22] *See, e.g.*, *Garnet Energy LLC*, 99 FERC ¶ 61,165 (2002).

[23] 18 C.F.R. § 385.214(c) (2004).

[24] 16 U.S.C. § 825l(a) (2000).

[25] 18 C.F.R. § 385.713(d)(1) (2004).

[26] *See, e.g.*, *CMS Midland, Inc.*, 56 FERC ¶ 61,177 at 61,623 (1991).

2. Motions for Stay

22. Montana-Dakota and Otter Tail each filed a motion for stay of the TEMT II Order as it applies to them. Montana-Dakota argues that failure to stay the order will cause irreparable harm to itself and the communities that it serves. It states that implementing the TEMT in the western edge of the Midwest ISO footprint before all seams issues have been resolved will impair reliability of service because that area is characterized by complex ownership and operational arrangements between Midwest ISO participants and non-participants. As a result, the Midwest ISO will not have full control over generating units that are jointly owned by Montana-Dakota and non-Midwest ISO participants, and that the non-participants can be expected to dispatch their generating facilities independently of the Midwest ISO. It adds that, while the Midwest ISO intends to manage transmission congestion using Locational Marginal Pricing (LMP), non-Midwest ISO participants can be expected to use all their transmission rights unless they are required to curtail service under Transmission Line-Loading Relief (TLR) procedures. Montana-Dakota further argues that participating in the TEMT would impose additional business risks and costs (including those for software and Schedules 16 and 17) on itself and its customers. It argues that because there is no evidence that the savings it will realize by participating in the TEMT will be greater than those costs, participating in the energy markets will have irreparable financial impacts.

23. Montana-Dakota argues that the issuance of a stay will not substantially harm other parties. It states that it does not seek a stay of the TEMT throughout the Midwest ISO footprint, but only as applied to its own system on the western border. It argues that it already has procedures and software needed to provide transmission service under the OATT, and that it is not aware of any reason why the Midwest ISO could not keep providing OATT service to utilities on the western edge of the Midwest ISO footprint while implementing the TEMT elsewhere. Finally, Montana-Dakota argues that the stay would not necessarily cause Montana-Dakota to refrain permanently from participating in the TEMT, but that it would protect Montana-Dakota until all issues related to its participation have been resolved.

24. Finally, Montana-Dakota argues that staying the effectiveness of the TEMT II Order as applied to Montana-Dakota is in the public interest. It states that imposing the TEMT on it would impair its ability to provide economic, reliable service to its customers. Montana-Dakota adds that the stay would also provide the Midwest ISO with an incentive to resolve seams issues sooner rather than later, and that denying the stay may allow the Midwest ISO to ignore its obligation to timely obtain seams agreements.

25. Montana-Dakota amended its motion for stay on September 28, 2004, arguing that certain rulings in the GFA Order support its conclusions that a stay is appropriate. Montana-Dakota notes that the Commission found in the GFA Order that the Midwest

ISO's peak load is 107,552 megawatts, and that it would be permissible to carve out of the TEMT loads totaling 10,285 megawatts (representing approximately 9.6 percent of the Midwest ISO's total load). Montana-Dakota states that the peak load on its transmission system is only 470 megawatts, or less than one-half of one percent of the Midwest ISO's peak system load. It avers that including its load in the carve-out would increase the overall carve-out to 10,855 megawatts (about 10 percent of Midwest ISO system load) and that, especially because its load is located on the western edge of the Midwest ISO footprint, there is no reason to believe that a small increase in the size of the carve-out would have a material impact on the Midwest ISO's ability to implement the carve-out.

26. Montana-Dakota further states that it has ownership interests with Otter Tail and certain non-Midwest ISO participants in two generating units. The GFA Order exempted delivery of power from one of those plants, and conditionally exempted delivery of power from the other plant, from the TEMT. Montana-Dakota also notes that the Commission ruled that transmission of electricity under other GFAs to which Montana-Dakota is a party would not be subject to the TEMT. It argues that it will be easier for the Midwest ISO to administer the TEMT if all load on the Montana-Dakota transmission system is exempt from the TEMT than if the Midwest ISO must separate the exempt load from the non-exempt load within the Montana-Dakota footprint. Montana-Dakota avers that promptly granting the stay it requests will enable the Commission to assure that the impact of carving the Montana-Dakota loads out of the TEMT can be addressed in the Midwest ISO's compliance filings, and thereby provide for development of a single, comprehensive plan for removing specified loads from the TEMT. Montana-Dakota notes that this would also resolve the South Dakota Commission's concerns regarding Montana-Dakota's continued participation in the Midwest ISO.[27]

27. Otter Tail argues that the only way to preserve its right to an appeal is to grant a stay of the TEMT II Order. It states that it will not be able to be put back into the same position if it wins before a court, and that that fact justifies the stay under law.[28] Without the assurance of a stay, Otter Tail says that it will have no choice but to prepare for the energy markets and to expend time, effort and money. (It estimates the net negative impact of the energy markets at the start-up date to range from $4.725 million to $7 million per year, with one-time up-front costs of $500,000 to $1 million.) Otter Tail

[27] These concerns will be described *infra*, in section IV.A.2.

[28] Otter Tail Request for Rehearing at 31 (citing *Scripps-Howard Radio, Inc. v. FCC*, 316 U.S. 4 (1942); *American Grain Ass'n v. Lee-Vac Ltd.*, 630 F.2d 245 (5th Cir. 1980); *Mesabi Iron Co. v. Reserve Mining Co.*, 268 F.2d 782 (8th Cir. 1959)).

argues that the Commission should grant a stay to allow it an effective future remedy and to prevent the expenditure of monies, which may later prove unnecessary.

28. As an initial matter, we disagree with Montana-Dakota's argument that it should be included in the carve-out that the Commission established in the GFA Order. The carve-out was created to address issues related to GFAs, not seams issues like those Montana-Dakota describes.

29. The Commission may stay its action "when justice so requires."[29] In addressing motions for stay, the Commission considers: (1) whether the moving party will suffer irreparable injury without a stay; (2) whether issuing the stay will substantially harm other parties; and (3) whether a stay is in the public interest.[30] The Commission's general policy is to refrain from granting a stay of its orders, to assure definiteness and finality in Commission proceedings.[31] The key element in the inquiry is irreparable injury to the moving party.[32] If a party is unable to demonstrate that it will suffer irreparable harm absent a stay, we need not examine the other factors.[33]

30. We find that Montana-Dakota and Otter Tail have not demonstrated that they will suffer irreparable harm absent a stay. Both utilities allege that they may suffer financial harm if a stay is denied. But "[m]ere injuries, however substantial, in terms of money, time and energy necessarily expended in the absence of a stay are not enough."[34] It is well settled that absent a threat to the existence of a movant's business (which neither party alleges is present here), "economic loss does not, in and of itself, constitute

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[29] 5 U.S.C. § 705 (2000).

[30] *See, e.g., CMS Midland, Inc., Midland Cogeneration Venture Ltd. P'ship,* 56 FERC ¶ 61,177 at 61,631 (1991), *aff'd sub nom. Michigan Municipal Coop. Group v. FERC*, 990 F.2d 1377 (D.C. Cir.), *cert. denied*, 510 U.S. 990 (1993).

[31] *Id.* at 61,630-31. *See also Wisconsin Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985).

[32] *See CMS Midland*, 56 FERC ¶ 61,177 at 61,631.

[33] *See id.*

[34] *Wisconsin Gas Co.*, 758 F.2d at 674.

irreparable harm."[35] We therefore deny Montana-Dakota's and Otter Tail's requests for stay of the TEMT II Order.

31. We also disagree with Montana-Dakota's and Otter Tail's arguments that moving the seam to the other side of their service territories – which would be the result of a stay – would make the seam easier to work with. First, seams agreements are necessary for reliability purposes whether Montana-Dakota and Otter Tail participate in the energy markets or not. Montana-Dakota appears to recognize this; it states in its motion for stay that "[i]t is likely that efforts to implement the TEMT in the western edge of the Midwest ISO footprint before all seams issues have been resolved will impair the reliability of service in the region."[36] Second, as further described *infra*, in section IV.K.1, a separate tariff would be needed to administer a physical rights system alongside a financial rights system. This would entail more than simple changes to the TEMT, and no party has submitted an additional tariff or proposed special procedures for Commission review. Moreover, as described below, the Commission expects that the benefits of participating in the energy markets will exceed the costs of implementing the markets.

32. Finally, we note that there has been progress toward seams resolution. On October 5, 2004, the Midwest ISO submitted its second compliance filing to the TEMT II Order. In that filing, the Midwest ISO reports that the non-Midwest ISO members of the Mid-Continent Area Power Pool (MAPP) have met with the Midwest ISO several times in the past six months to develop a seams agreement; that the parties have reached an agreement in principle; and that they expect that agreement to be finalized and filed with the Commission by December 1, 2004.[37] If such an agreement is filed with and accepted by the Commission, it should moot Montana-Dakota's and Otter Tail's concerns. We urge the parties to finalize this agreement and file it by December 1, 2004.

3. Motion for Expedited Action

33. WUMS Load-Serving Entities note that the Midwest ISO's FTR allocation process must begin in October, probably before the Commission will be able to provide guidance on the Midwest ISO's October 5, 2004 compliance filing. WUMS Load-Serving Entities

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[35] *Id.*

[36] Motion of Montana-Dakota Utilities Co. for Stay of Order Issued August 6, 2004 at 5, Docket No. ER04-691-000 (Sept. 8, 2004).

[37] Midwest ISO Transmittal Letter at 44, Docket Nos. ER04-691-007 and EL04-104-006 (Oct. 5, 2004).

state that this places them in a "catch-22" situation, as they must adhere to the Commission's conditions in the FTR allocation process in order to qualify for expanded congestion cost coverage. They therefore ask the Commission to act on their request for rehearing prior to the beginning of the FTR allocation process.

34. By issuing this order, we grant WUMS Load-Serving Entities' request for action prior to the beginning of the FTR allocation process. That process, as stated in the Midwest ISO's October 18, 2004 compliance filing, will not begin until November 22, 2004.[38]

4. Grandfathered Agreements

a. Requests for Rehearing

35. Cinergy states that its understanding, based on the TEMT II Order, is that the Commission reserved issues relating to GFAs for future decision. It notes that the Commission accepted the TEMT for filing without stating that the TEMT remains subject to modification based upon the resolution of the GFA issues pending in this docket. Cinergy requests clarification that acceptance of the TEMT was conditioned upon incorporation of any changes required as a result of full resolution of the outstanding GFA issues. Alternatively, Cinergy seeks rehearing and a determination that Option B is unlawful, for all the reasons stated in its prior pleadings.

36. Joint Cooperatives argue that the three-step analysis established in the Procedural Order is fundamentally flawed, procedurally and in terms of its scope, as they described in their request for rehearing of the Procedural Order. They further argue that the briefs on exceptions filed in response to the Presiding Judges' Findings of Fact in the three-step investigation are not a sufficient basis to warrant abrogating GFAs. Joint Cooperatives further argue that the issuance of the TEMT II Order before the conclusion of the three-step investigation is premature and erroneous. They quote the Commission's statement in the Procedural Order that the Commission "cannot thoroughly evaluate the proposed TEMT unless we develop a full understanding of the effect of the Midwest ISO's proposed tariff changes on the GFAs, and the magnitude of the GFAs' impact on the proposed energy markets."[39]

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[38] *See* Midwest ISO Compliance Filing, Revised FTR Allocation Timeline Attachment, Docket Nos. ER04-691-009 and EL04-104-008 (Oct. 18, 2004).

[39] Joint Cooperatives' Request for Rehearing at 16 (quoting Procedural Order at P 62).

37. Joint Cooperatives argue that the TEMT II Order abandoned the process the Commission created to address the GFA issues first. They note that the TEMT II Order was issued nine days after the Presiding Judges' Findings of Fact, and that the order fully addressed the merits of the proposed TEMT. Joint Cooperatives also state that they are concerned about the schedule the Commission described in the TEMT II Order. They argue that the expedited order on GFA issues the Commission promised probably would not be issued until at least mid-September. They argue that proceeding with FTR nominations in the October 1, 2004 time frame will not afford parties to the GFAs time to knowledgeably make decisions that will have significant economic impacts, violating their fundamental rights to due process and causing irreparable harm. Thus, Joint Cooperatives conclude that the TEMT II Order: (1) is premature because it addresses the merits of the TEMT before GFA issues are resolved; (2) is arbitrary, capricious, and not based on substantial evidence; and (3) violates the due process rights of the participants in the three-step analysis.

38. Midwest Parties argue that the approval of the TEMT, absent a decision on how GFAs will be treated, fails to provide GFA parties with reasonable notice of how their rights will be affected. Midwest Parties state that the decision lacks reasoned decision-making in that the Commission had stated in the Procedural Order that GFA issues must be determined prior to considering the merits of the TEMT. They note that the TEMT order was issued less than a week and a half after Step 2 of the GFA investigation ended, and that this could only mean that the merits of the TEMT had already been determined. Midwest Parties allege that one cannot reasonably conclude that the Commission has engaged in reasoned decision-making, given its failure to articulate how it intends to handle the "threshold" issue of GFAs.

39. Midwest Parties further state that the Commission's promise to expedite the GFA Order is of little comfort because, with less than a month before FTR nominations are due, GFA parties do not know whether and how the Commission intends to address the Midwest ISO's presumption that the market is incompatible with maintaining the rights of the GFA parties, among many other issues. Assuming that the GFA Order is issued prior to October 1, Midwest Parties argue that they will have little time to read and digest the decision before they must make decisions with large economic implications. They add that potential challenges to that decision will have to be made after FTR allocations and nominations have at least begun before any rehearing and appeals can be filed and considered.

40. Finally, Midwest Parties argue that, despite the seriousness and complexity of the TEMT undertaking, the Commission has cast aside due process in its rush to meet its March 1, 2005 deadline. They allege that the Commission denied market participants the right to conduct discovery, proffer testimony and cross-examine the Midwest ISO's witnesses, thereby failing to create a record upon which a reasonable decision can be

made. Midwest Parties further aver that the Commission has not required the Midwest ISO to establish that the TEMT and its treatment of GFAs is just and reasonable, but has presumed as true the Midwest ISO's concerns about the incompatibility of GFAs and its market proposal. Next, Midwest Parties argue that the Commission issued a comprehensive order on the TEMT without considering the impact of, or on, GFAs, without making a determination on the imposition of Schedule 16 and 17 cost adders, and without knowing who is responsible for what reliability functions. They add that the TEMT II Order does not address or satisfy due process concerns that Midwest Parties have raised. They urge the Commission to reconsider that order to allow for a more meaningful examination of the TEMT proposal, including GFA issues.

41. Otter Tail argues that the Midwest ISO's September and October finish dates for FTR tasks are unrealistic, because none of those tasks can be achieved without the Commission's order regarding GFAs.[40]

42. Manitoba Hydro objects to provisions of the TEMT that impose on parties to GFAs obligations such as congestion and marginal loss costs, uplift charges and Schedule 16 and 17 charges. It argues that many of these obligations conflict with provisions in existing agreements, and that in all cases the additional costs undermine the economic assumptions that formed the parties' basis for committing to the agreements. Manitoba Hydro argues that its GFAs are only partially subject to the Commission's jurisdiction, and that it is not a public utility as defined in the FPA. Accordingly, it states that the Commission should have held that Manitoba Hydro's transmission service and sales of energy outside the United States is not subject to Commission jurisdiction and excluded from the expedited hearing GFA parties' transmission service within Canada. Manitoba Hydro states that the Commission's failure to do so may mean: (1) that the Commission and the Midwest ISO may have concluded that the TEMT is applicable to transmission service within Canada; and (2) that the Commission may seek to modify the terms and conditions under which transmission service is provided in Canada. Where the Commission lacks jurisdiction, or has only partial jurisdiction, over existing agreements, it cannot modify portions of these agreements without altering the non-jurisdictional aspects of the agreement or undoing the bargain as a whole, says Manitoba Hydro. Manitoba Hydro adds that without the parties' consent and consistent with the terms and conditions governing modification of the underlying contracts, the Midwest ISO cannot unilaterally alter provisions in the underlying agreements or superimpose provisions that would have the same effect as modification. Manitoba Hydro seeks Commission clarification of this issue.

[40] Otter Tail Request for Rehearing at 27-28.

b. Discussion

43. The TEMT II Order acknowledged that, as outlined in the Procedural Order, the Commission could begin to evaluate how the GFAs should be treated in the Midwest ISO's energy markets after Step 2 of the three-step investigation had ended with the Presiding Judges' presentation of the hearing results to the Commission.[41] The TEMT was accepted subject to further orders on GFAs and the ongoing proceeding regarding Schedules 16 and 17.[42] The outcome of those further orders could have been – and, in the case of the GFA Order, was – that the Commission required the Midwest ISO to make changes to the TEMT.[43] We therefore grant Cinergy's request for clarification of the procedural posture of the TEMT II Order, and we do not need to reach its request for rehearing with regard to the same issue.

44. We deny Joint Cooperatives' and Midwest Parties' requests for rehearing insofar as they attack the issuance of the TEMT II Order before the end of the three-step investigation. The Procedural Order made abundantly clear that the Commission expected the process of investigating the GFAs to move forward during the same time the Commission was evaluating the merits of the TEMT. The Procedural Order stated that Step 1 of the three-step investigation would conclude on June 25, 2004;[44] Step 2, on July 28, 2004;[45] and Step 3 in time to allow Midwest ISO market participants to begin their FTR nominations on October 1, 2004[46] – the day the Commission set for FTR nominations to begin.[47] If FTR nominations were to begin on October 1, 2004, then the Commission's analysis of the TEMT would have had to be completed prior to this date so that the appropriate tariff sheets could be made effective. The Commission was required

[41] *See* TEMT II Order at P 11.

[42] *See id.* at P 3, 645.

[43] *See* GFA Order at P 264.

[44] *See* Procedural Order at P 68.

[45] *See id.* at P 76.

[46] *See id.* at P 78.

[47] *See id.* at P 96.

to act in accordance with statutory deadlines,[48] and the process delineated in the Procedural Order made clear how the Commission would fulfill those obligations. Further, as described in response to Cinergy's arguments, the Commission's acceptance of the TEMT was made subject to further order on the GFAs. If the GFA issues had been so intractable as to make it impossible for the Midwest ISO to start its energy markets, or if further proceedings were needed, the Commission could (and would) have made this finding in the GFA Order and, if necessary, rejected the TEMT at that time. This reasoning also applies to Midwest Parties' arguments that the Commission should not have made a determination on the TEMT without also making a determination on the imposition of Schedule 16 and 17 cost adders, and that the Commission erred in failing to present the results of the GFA investigation concurrently with the TEMT Order.[49] As stated above, the Commission retained throughout the process its authority to reject the TEMT on the ground that the Midwest ISO would be unable to reliably accommodate the GFAs in its energy markets. We therefore reject Joint Cooperatives' and Midwest Parties' arguments that the TEMT II Order was arbitrary, capricious, not based on substantial evidence, and violative of due process.

45. We also deny Midwest Parties' request for rehearing to the extent that it alleges the Commission has cast aside due process in order to meet the March 1, 2005 start-up date for the energy markets. Midwest Parties' arguments that the Commission has not permitted it an opportunity to conduct discovery, proffer testimony and cross-examine the Midwest ISO's witnesses amounts to an argument that the Commission should have set the TEMT for trial-type evidentiary hearing. As we describe *infra*, in response to other requests for rehearing, the record in this proceeding is sufficient to allow us to make a reasoned decision on the merits of the TEMT, and trial-type evidentiary hearing procedures have not been necessary.

46. We will dismiss other arguments on the ground that they address the substance of the Procedural Order, and the time line established in that order. These arguments are not properly at issue here and are more appropriately addressed on rehearing of that order: (1) Midwest Parties' arguments that they lack time to consider the implications of the GFA Order before engaging in FTR nominations; (2) Joint Cooperatives' argument that

[48] The Midwest ISO proposed in the March 31 Filing to make some portions of the TEMT effective June 7, 2004, and the remainder on December 1, 2004. The Commission was required to act on the entire TEMT within those deadlines. *See* 18 C.F.R. § 824d (2000).

[49] We will address Midwest Parties' arguments regarding the allocation of reliability functions *infra*, in section IV.C of this order.

the three-step GFA analysis is flawed; (3) Joint Cooperatives' argument that the briefs on exceptions filed in response to the presiding judges' findings of fact are an insufficient basis for abrogating GFAs; (4) Joint Cooperatives' and Midwest Parties' arguments that proceeding with FTR nominations on October 1, 2004 does not allow market participants enough time to digest the Commission's final decision on GFAs and participate in the nomination process; and (5) Otter Tail's argument that the Midwest ISO's September and October finish dates for FTR tasks are unrealistic.

47. Manitoba Hydro's arguments address the effect of the TEMT on GFAs, through imposition of additional charges, and the extent of the Commission's authority to modify Manitoba Hydro's GFAs. These arguments also appear to be directed to the substance of the Procedural Order and the GFA Order, and are more properly raised in response to those orders. We will therefore dismiss them. However, we assure Manitoba Hydro that our rulings on the TEMT and GFAs apply only to jurisdictional services in interstate commerce, not to services provided within Canada.

5. Other Procedural Arguments

a. Requests for Rehearing

48. LG&E argues that the Commission committed reversible error when it approved the TEMT without ordering a hearing. It adds that the Commission erred by summarily accepting the TEMT even though the Midwest ISO failed to demonstrate that the TEMT was just and reasonable under section 205 of the FPA. It states that Day 2 cannot be found just and reasonable on a summary basis; "[s]uch a major departure from standard operating procedure in the Midwest" requires a hearing, and the fact that there are such divergent views among stakeholders should be investigated more.[50] LG&E states that the length of the stakeholder process does not mean that stakeholder concerns were adequately addressed or that the stakeholders and the Midwest ISO reached agreement on critical issues. It alleges that the Midwest ISO largely disregarded whatever stakeholder involvement occurred; thus, a hearing is needed to resolve disputed issues of material fact.

49. LG&E argues that in the case of PJM and NYISO the transmission owners made the proposal, supported the filings (as did state commissions) and that consensus was reached because transmission owners and state commissions projected net benefits from the new market structures. By contrast, LG&E argues that in the Midwest, the Midwest ISO proposed its own market structure without meaningful transmission owner

[50] LG&E Request for Rehearing at 11.

involvement, and that there was no consensus among transmission owners and state commissions. Ultimately, LG&E says, the TEMT suffers because the industry was consulted, but largely ignored, in the creation of the Day 2 energy markets.

50. LG&E goes on to argue that this case is unique for a number of reasons. First, LG&E says, the stakes are higher than usual because the Commission is imposing a centralized power pool on an area of the nation that lacks experience with such pool. Theoretical reliance on PJM, NEPOOL and NYISO is misplaced because it does not adequately account for the peculiarities of the Midwest markets. LG&E argues that the impact of the order is not only to change the economic dynamics of the Midwest's electric industry, but to reshape its operations. LG&E argues that the public interest requires a more thorough review through an evidentiary hearing, a rulemaking procedure or a transition period during which concerned utilities may "sit out" the Day 2 markets. Second, LG&E argues that key issues in this case cannot be determined on the written record of the proceeding. It states that it has raised questions throughout the process that have never been answered to its satisfaction, and that it cannot assume that these questions will be resolved satisfactorily. Third, LG&E states that adequate procedural due process has not been afforded because no trial-type evidentiary hearing has been held on the substantive provisions of the TEMT. Fourth, LG&E argues that there is a need to determine the motive, intent and/or credibility of the witnesses in this case because intervenors were not given an opportunity to challenge the witnesses' testimony through cross-examination or data requests. It particularly challenges the testimony of Dr. McNamara, who it states has not been shown to be competent on reliability issues. Finally, LG&E argues that it has provided enough evidence to place a material fact in dispute in this case. It concludes that the Commission has acted inconsistently with its regulations by summarily approving the TEMT, and therefore has fallen short of its statutory obligation.[51]

51. LG&E challenges the notion that all loads and customers will benefit from the TEMT. It argues that the Commission has never tested this premise in a trial-type evidentiary hearing. It cites the Kentucky Public Service Commission's (Kentucky Commission) investigation into whether LG&E should be a member of the Midwest ISO or a southern RTO. LG&E now argues that that proceeding is ongoing, that a procedural schedule has been set, and that the Kentucky Commission plans to take testimony and hold a trial-type evidentiary hearing. Given these circumstances, LG&E argues that the Commission must establish additional hearing procedures in this case to adduce evidence about whether the costs of the TEMT outweigh the benefits for Midwest ISO customers

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[51] LG&E Request for Rehearing at 16 (citing FPA section 313(b), 16 U.S.C. § 825l).

such as LG&E. LG&E argues that the Commission has not reviewed the cost impacts of the TEMT as a whole. It believes that it has shown that the Commission should have suspended the TEMT and set if for hearing because the rates may be excessive and have not been shown to be just and reasonable. It adds that by failing to suspend the rates and set them for hearing, the Commission has committed reversible error.

52. Finally, LG&E argues that it may be inappropriate to impose PJM and NYISO policies on the Midwest ISO by assuming (without explanation or a trial-type evidentiary hearing) that these policies are appropriate in the Midwest. LG&E notes that while PJM and NYISO had previously operated as tight power pools, the Midwest ISO has not. It believes the Commission inappropriately relied on other ISOs for precedent when it: (1) required the Midwest ISO to offer the "redirect" option for zonal FTR requests without explaining why this PJM option will work in the Midwest; (2) adopted a $1,000/MWh bid cap without accounting for the fact that PJM, NYISO and ISO-NE have capacity markets, but the Midwest ISO does not; and (3) conditionally accepted the Midwest ISO's credit policy, without explaining how PJM's or NYISO's credit policies might be appropriate for the Midwest. LG&E believes that the Commission relies too heavily on PJM or other ISO policies without analyzing the policies' impact on the Midwest.

53. Joint Cooperatives argue that the TEMT II Order erred by accepting the proposed TEMT even though the TEMT had not been shown to be just and reasonable. They allege that the TEMT II Order presupposed that there would be benefits to customers in the statement that "Our order benefits customers because it opens the way for the Midwest ISO to initiate energy markets, increasing system reliability and competition in the Midwest ISO region."[52] Joint Cooperatives argue that that finding is not based on substantial evidence in the record and that it is arbitrary and capricious. The record, they say, does not contain enough evidence to support a conclusion that the TEMT is just and reasonable.

54. Joint Cooperatives next argue that the TEMT II Order found that implementation of the TEMT II Order would provide reliability benefits, and that this finding goes beyond the findings of the Procedural Order without any better information in the record than was before the Commission at the time the Commission issued the Procedural Order. Joint Cooperatives also argue that the TEMT II Order does not consider the additional information that the Midwest ISO and other parties filed in Step 1 of the GFA investigation, and that the information the Midwest ISO submitted shows that the Midwest ISO's claims of enhanced reliability are unsupported.

[52] *Id.* at 6 (citing TEMT II Order at P 3).

55. Joint Cooperatives argue that the TEMT imposes significant fees on load-serving utilities, regardless of whether they are members of the Midwest ISO and without any demonstration that load-serving entities or their customers gain value from the Midwest ISO in return for these higher costs. They note that many protests to the March 31 Filing argued that the benefits of the TEMT had not been demonstrated and, citing the Procedural Order, argue that the Commission apparently agreed.[53] Joint Cooperatives note that the Procedural Order required the Midwest ISO to file further information demonstrating the benefits of the proposed TEMT.[54] They state that the evidence submitted in the paper hearing that the Procedural Order opened calls into question whether the benefits of the TEMT outweigh the costs. Joint Cooperatives add that the "limited, questionable evidence" that the Midwest ISO filed addresses benefits in the aggregate across the Midwest ISO, but that there is no evidence that demonstrates that any particular customer will benefit.[55]

56. Next, Joint Cooperatives argue that although the TEMT II Order found that customers will benefit from the TEMT, it dismissed the contentions that the benefits of the TEMT will not exceed the costs because that issue was the subject of a paper hearing in Docket No. ER02-2595.[56] Joint Cooperatives argue that the Commission had not yet made a decision in Docket No. ER02-2595, and that it was arbitrary and capricious for the Commission to rely on the unmade decision to support an assumption that net benefits will result from implementing the proposed TEMT. Moreover, Joint Cooperatives argue that the issues in Docket No. ER02-2595 are different from those before the Commission in this docket. That proceeding, they say, was limited to determining that appropriate cost allocations for Schedules 16 and 17 and the appropriate exit fee for withdrawing from the Midwest ISO, and does not address the proposed TEMT. They argue that the forthcoming decision in the paper hearing would have no bearing on the issue of whether the TEMT's benefits will exceed the costs of implementing it. Joint Cooperatives argue that the claim that the Commission's conclusions in Docket No. ER02-2595 should be given preclusive effect as to the costs and benefits of the TEMT is inconsistent with the doctrine of collateral estoppel. They state that that doctrine holds that, for a finding to be given preclusive effect in subsequent litigation, the finding must have been actually litigated by the parties and decided by the tribunal, and the preclusion of the issue in the

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[53] *Id.* at 7 (citing Procedural Order at P 54, 72).

[54] *Id.* at 7 (citing Procedural Order at P 73).

[55] *Id.* at 8-9.

[56] *Id.* at 9 (citing TEMT II Order at P 3, 577 n.337).

second litigation must not work an unfairness. Further, Joint Cooperatives argue that the Commission recognized in Docket No. ER02-2595 that RTO development costs must be contained to maximize their net benefits, and that the Commission also required the Midwest ISO to submit informational filings to address concerns about the level of its expenditures.[57] Joint Cooperatives conclude that relying on Docket No. ER02-2595 as a means to avoid addressing whether the proposed TEMT would result in net benefits is misplaced.

57. Montana-Dakota argues that it demonstrated in its protest that the TEMT should be rejected. It identified deficiencies including: (1) inadequate modeling of the transmission system for purposes of modeling FTRs; (2) failure to submit completed seams agreements; and (3) failure to provide details relating to implementation of Module E. Montana-Dakota argues that the Commission confirmed in the TEMT II Order that these deficiencies exist and required compliance filings and settlement judge procedures. It states that, in the absence of a full and complete proposal, the Commission "could not and did not find that the TEMT was just and reasonable," and parties are denied the opportunity to evaluate and comment on the proposal in a comprehensive manner.[58] Montana-Dakota argues that this deprived it of the opportunity for a trial-type evidentiary hearing, and that the Commission failed to explain why its acceptance of an incomplete proposal will protect the rights of all interested parties. Montana-Dakota notes that the TEMT I Order sympathized with the concerns of commenters and protestors that the July 25 Filing was incomplete,[59] and alleges that the Commission's directives to remedy the deficiencies of the March 31 Filing do not justify its failure to reject the filing.

58. Montana-Dakota further argues that the Commission has provided insufficient guidance to enable the Midwest ISO to remedy certain deficiencies in the TEMT. Without such guidance, Montana-Dakota says, neither the Commission nor interested parties can envision or fully evaluate the end product. Implicit in the Commission's acceptance of the TEMT subject to modifications is the assumption that all the necessary modifications will be filed and acted upon by the Commission before March 1, 2005. Montana-Dakota argues that the Commission's expectation that the Midwest ISO can meet this schedule is not justified, and that rejecting the TEMT would have assured that all parties had adequate time.

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[57] *Id.* at 10 (citing *Midwest Independent Transmission System Operator, Inc.*, 103 FERC ¶ 61,035 (2003)).

[58] Montana-Dakota Request for Rehearing at 7.

[59] *Id.* (citing TEMT I Order at P 22).

59. Next, Montana-Dakota argues that there is no evidence that the TEMT is needed to facilitate development of competitive wholesale electricity markets within the Midwest ISO footprint. It notes that the Midwest ISO already performs each of the functions that Order No. 2000 requires of an RTO. In the absence of any valid reason to expedite implementing the TEMT, Montana-Dakota argues that the Commission should have required the Midwest ISO to file a fully-developed energy markets tariff before accepting it for filing.

b. Discussion

60. We deny Montana-Dakota's request for rehearing to the extent it argues that the TEMT is unnecessary and that the Commission should have rejected it as incomplete. The question of whether the TEMT is creating a competitive wholesale electricity market in the Midwest is not at issue here. Rather, the Commission's obligation is to review the TEMT proposal, which was filed pursuant to section 205 of the Federal Power Act, to ensure that it is not unjust, unreasonable, unduly discriminatory or preferential.[60] We made these findings in the TEMT II Order.

61. As Montana-Dakota states, the July 25 Filing was incomplete, and the Commission granted the Midwest ISO's motion to withdraw that filing.[61] But this precedent does not require us to reject the March 31 Filing out of hand. There is a world of difference between the July 25 Filing – which lacked entire sections as critical as Modules D and E – and the March 31 Filing. The latter shows the Midwest ISO's and stakeholders' response to the guidance in the TEMT I Order and is, in its entirety, a workable proposal. Moreover, the Commission routinely accepts tariff filings – and has even accepted past Montana-Dakota filings, without objection from Montana-Dakota[62] – subject to further modification. It is unrealistic to expect the Midwest ISO to propose an entirely new tariff that would be so perfectly crafted as to require no further work whatsoever.

62. We also disagree with Montana-Dakota that the Commission did not provide sufficient guidance to the Midwest ISO to allow it to make appropriate compliance filings, and that there is not sufficient time before March 1, 2005 to evaluate all the filings. The Midwest ISO did not seek rehearing or clarification of the TEMT II Order,

[60] *See* 16 U.S.C. 824d (2000).

[61] *See* TEMT I Order at P 3, 22.

[62] *E.g., Montana-Dakota Utilities Company*, 85 FERC ¶ 61,062 at 61,201 (1998).

and this suggests that it understands its obligations going forward. Moreover, it has already made three such compliance filings. In creating a revised schedule for energy market start-up,[63] and in acting on the various filings already made in this proceeding, the Commission took into account the time it would need to process any necessary compliance filings by March 1, 2005. We will continue to be equally mindful of this time frame.

63. The process of formulating the TEMT did not deprive Montana-Dakota of an opportunity for hearing on any aspect of the TEMT. In this regard, Montana-Dakota may continue to file protests to the compliance filings as the Midwest ISO makes them, just as it has filed various pleadings to date. We also strongly disagree with Montana-Dakota's argument that rejection of the TEMT is the only way to assure that all parties have adequate time to evaluate the proposal. As described in the TEMT II Order, and repeated here, a lengthy stakeholder process has preceded the TEMT proposal.[64] Parties have also had an opportunity to comment on the TEMT proposal at issue here, and on the compliance filings ordered to date, and their comments demonstrate a depth of understanding of the TEMT proposal. We therefore deny Montana-Dakota's request for rehearing to the extent it alleges that the Commission has not provided adequate due process.

64. We deny LG&E's and Joint Cooperatives' requests for rehearing of the Commission's decision to accept the TEMT without setting it for trial-type evidentiary hearing. Although we agree with LG&E that the TEMT will carry a significant impact, we do not agree that the rates have not been shown to be just and reasonable. The TEMT is, at this point, a proposal to become effective March 1, 2005, and all discussion of the impact it will have is necessarily theoretical – just as is the case with any rate filing by any public utility.[65] The parties, moreover, have submitted substantial arguments and evidence on paper that has aided us in making the finding that the rates, as amended, are just and reasonable. To date, a trial-type evidentiary hearing has not been necessary to resolve the issues in this docket (save for issues surrounding the nature of the individual GFAs, which the Procedural Order set for hearing). To protect against, *inter alia*, difficulties in market start-up that cannot be predicted in advance, the TEMT II Order

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[63] *See* Procedural Order at P 94-101.

[64] *See* TEMT II Order at P 26-32.

[65] *See* 16 U.S.C. § 824d(d) (2000) (requiring that public utilities, absent waiver of prior notice, must allow the Commission 60 days before a proposed rate filing becomes effective).

prudently imposed market start-up safeguards for a transition period while the Midwest ISO and its members gain experience with the markets. We therefore find once again that a paper hearing has been sufficient to resolve the issues in this docket.[66] We deny rehearing of the parties' requests for a trial-type evidentiary hearing on non-GFA issues.

65. Further, we deny LG&E's request to be able to "opt out" of various sections of the tariff. As we will explain in further detail below, the TEMT permits LG&E to choose whether any or all of its resources will be committed to the Midwest ISO markets. Only the portion of those units designated by a market participant as network resources are committed to the Midwest ISO markets. Thus, because LG&E already has the ability to choose to keep some or all of its resources out from under Midwest ISO's control, there is no need to provide LG&E a right to opt out of this portion of the tariff.

66. Joint Cooperatives and LG&E each argue that the issue of whether the TEMT provides net benefits has not been resolved, and that this issue should have been set for trial-type evidentiary hearing. Joint Cooperatives are incorrect. The Commission stated that "[o]ur order benefits customers because it opens the way for the Midwest ISO to initiate energy markets, increasing system reliability and competition . . . ." The sentence reflects the Commission's expectation, described in the Procedural Order, that at the end of the day the energy markets will benefit customers and improve reliability.[67] As Joint Cooperatives acknowledge, the Commission asked questions about costs and benefits in the Procedural Order, and required the Midwest ISO and the IMM to make further filings that would describe those costs and benefits (including reliability benefits) in further detail. The GFA Order addressed those filings and, as described below, found that the energy markets will benefit customers and improve reliability in the Midwest.

67. Joint Cooperatives is correct that the paper hearing in Docket No. ER02-2595 only addressed the allocation of Schedules 16 and 17 charges, and that the Commission should not have relied upon that proceeding, still in progress at the time of the TEMT II Order, to provide evidence that there would be net benefits from the energy markets. We find on rehearing, however, that this error was harmless because the Commission was investigating the net benefits of the energy markets in the instant dockets. As the GFA Order described, there is sufficient evidence for the Commission to find that the Day 2

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[66] Nor is a trial-type evidentiary hearing necessary; the Commission is allowed to rule summarily on the basis of a paper hearing. *E.g., Southern California Edison Company*, 70 FERC ¶ 61,087 at 61,251 & n.43 (1995). LG&E's request for a rulemaking proceeding will be addressed *infra*, in section IV.E.5.iii.

[67] *See* Procedural Order at P 3, 54, 64.

energy markets will have both economic and reliability benefits for customers in the Midwest ISO region. With respect to public benefits of the TEMT in general, the GFA Order found that "[b]ecause implementing the TEMT even with a GFA carve-out will still expand the use of economic dispatch, aggregate costs under the new Day 2 markets should still be less than under the status quo Day 1 market and the overall efficiency of the market would improve."[68] With respect to reliability, the GFA Order concluded that, "based on the evidence and analysis presented, the Midwest ISO can reliably operate the Day 2 Energy Markets with some GFAs that are carved out from TEMT scheduling. . . . [E]ven with a carve-out and the inefficiencies that could result, we believe that the Day 2 Energy Markets will be more reliable and efficient overall than the current Day 1 energy markets."[69] We therefore deny LG&E's request for rehearing to the extent it alleges that the Commission has not addressed the overall costs and benefits of the Day 2 energy markets.

68. LG&E argues that the Midwest ISO has not shown that the TEMT will benefit all customers, and that the fact there was a stakeholder process does not mean that the stakeholders' views were taken into account. We note, however, that there seems to be significant consensus among stakeholders that the Midwest ISO's energy markets will benefit the Midwest, and we also note that no stakeholder but LG&E has made the same challenges to the stakeholder process. Further, LG&E does not explain how the stakeholder process, or the results of the stakeholder process, have harmed the TEMT. Finally, while we agree that consensus among stakeholders and state commissions is desirable in starting ISOs and RTOs, the Midwest ISO has the latitude to make proposals with less than unanimous support.[70] Therefore we deny rehearing on this issue.

69. Finally, we deny LG&E's request for rehearing on the ground that it may be inappropriate to impose PJM and NYISO policies on the Midwest ISO. It is true that the Midwest ISO has not previously operated as a tight power pool, and that beginning Day 2 operations in the Midwest may be substantially different from what took place in the Northeast. However, our obligation to ensure just and reasonable rates for Midwestern customers demands that we examine what has worked well – and what has not – in all RTOs and ISOs to provide the best possible guidance to the Midwest ISO. We also bear

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[68] GFA Order at P 100.

[69] *Id.* at P 89. *See also* GFA Order at P 89-98.

[70] *See* TEMT II Order at P 30 (finding that there are no requirements in the Transmission Owner Agreement that the Midwest ISO bring items to a vote in the Advisory Committee prior to filing with the Commission).

in mind that it is necessary to good RTO and ISO operations to work well with neighboring RTOs and ISOs, and that one way to reduce seams is to promote consistency between the Midwest ISO and its neighbors.

B. Readiness and Market Startup Safeguards

1. Reliability, Performance Assessment and Audit

a. Market Readiness

i. Background

70. In the TEMT II Order, the Commission required the Midwest ISO to: (1) consult with OMS and adopt its recommendations for metrics related to commercial operations readiness and the testing plan; and (2) certify to the Commission, 30 days before market start-up, the reliability and readiness of its systems.[71] The TEMT II Order stated that the Commission would not approve the start of the markets until it received this certification. The Commission also ordered the Midwest ISO to file an independently-evaluated Verification Plan at least three months prior to market start and an explanation of how the transition of functional responsibilities will not adversely affect reliability. The TEMT II Order also asked OMS to make an informational filing to advise the Commission of its views on market readiness.[72]

ii. Requests for Rehearing

71. A number of parties contend that the market is not ready to start, and that the safeguards provide inadequate protection. Joint Cooperatives state that time needs to be built in for: (1) an independent evaluation by the NERC Operating Committee, as that committee has requested; (2) interested parties and the Commission to analyze and comment on the NERC results; and (3) evaluation of Midwest ISO actions in response to comments by NERC, the Commission and interested parties.[73] Also, Joint Cooperatives claim that the Commission acted arbitrarily in accepting the TEMT before resolving the reallocation of functions between the Midwest ISO and control areas. Finally, Joint

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[71] TEMT II Order at P 55.

[72] TEMT II Order at P 55.

[73] *See* Joint Cooperatives at 20 (citing NERC Operating Committee Resolution Regarding Midwest ISO (March 25, 2004)).

Cooperatives cite a number of unresolved market issues, such as consolidation of control areas, lack of FTR options, lack of long-term FTRs, incomplete review of market monitoring units, lack of fast-track mechanisms to process tariff changes, and lack of a complete resource adequacy plan, as additional evidence that the Midwest ISO market is not ready to start.

72. Consumers states that proper training is needed of Midwest ISO personnel on control and subcontrol area responsibilities before the markets start, so that market start-up will not harm customers in the lower peninsula of Michigan. Consumers urges the Commission to grant rehearing to determine if the functional split of responsibilities, the subject of settlement judge procedures, is appropriate in lieu of training and to implement a process to transition post-Day 2 functional tasks to Midwest ISO personnel that includes metrics. Consumers also recommends verification by market participants of market readiness.

73. Midwest Parties considers remedial safeguards an inferior approach, and request rehearing on the need for four to six months of parallel runs before market start-up to build confidence in computer systems and in the Midwest ISO's ability to operate the market, as well as to demonstrate the economic impacts of FTRs and LMPs. Midwest Parties cite to the failure of the Midwest ISO to meet milestones and the lack of evidence that the market will survive seasonal peaks as support for its request. Midwest Parties also request Midwest ISO to identify the Readiness Advisor and highlight the Readiness Advisor's testing and reporting plans.

74. LG&E argues that the Commission erred by failing to investigate further whether Day 2 is ready for implementation. First, it notes that the Commission required the Midwest ISO to submit a detailed cutover plan to support reversion to reliable system operations and transmission scheduling in the event of system failure. LG&E argues that, in doing so, the Commission recognized that a system failure may occur after start-up. It notes that other RTOs and ISOs that previously operated as power pools suffered from such start-up software failures. LG&E argues that it is possible for procedures to be proposed and developed through a hearing process that would eliminate the need for such a cutover plan. Second, LG&E notes that the TEMT II Order gave the Midwest ISO authority to revise LMPs *ex post* under certain conditions. LG&E further argues that the Commission's recognition that revised LMPs are needed for transitory errors, system failures and other operational problems heightens concern about the readiness of Day 2 and its susceptibility to errors. Third, LG&E avers that the need for transitional safeguards against exposure to excessive marginal loss charges and FTR allocation shortfalls shows that Day 2 is not ready and may not be a market panacea. It argues that the five-year transitional safeguard to suspend marginal loss charges above average or historical levels, and the enhanced congestion hedge made available for entities in NCAs, demonstrate that the Commission is not comfortable with the full implementation of

Day 2. LG&E also believes that the Commission's recognition that there may be unanticipated price volatility at the start-up of a new market indicates that it is moving too fast toward Day 2. For all these reasons, LG&E believes that the Commission erred by failing to recognize that Day 2 is not ready, and that fact should be adduced on the record to determine whether and how the system can be implemented reliably and cost-effectively.

iii. Discussion

75. As an initial matter, we must clarify a differentiation between reliability issues and energy market start-up issues. Reliability issues encompass safe and effective functioning of hardware and software monitoring and analysis tools, such as the State Estimator and various flow monitoring programs, communication protocols and application of NERC guidelines. The Commission's verification of system readiness is based on NERC audits with our participation, and is not dependent on evaluations by other parties or the need to wait for parallel running and testing of the energy market model. With respect to reliability issues, our evaluations to date indicate that the Midwest ISO is taking the necessary steps to manage reliability over its system, and we will continue to audit these reliability activities. Market start-up is a separate issue. The focus of market start-up, or market readiness, is the functioning of the Security Constrained Economic Dispatch and Security Constrained Unit Commitment models, as well as the effectiveness of the bidding and scheduling procedures. We note that the Midwest ISO has a market start-up plan that includes market testing with parallel operations and FTR allocations. We also stated in the TEMT II Order that we would not approve the start of markets until they have been certified to be ready. We note that we will be revisiting the issue of market readiness on numerous occasions over the next several months, as the Midwest ISO makes filings documenting its progress, and therefore we, and market participants, will have ample opportunity to ensure every action is being taken that is necessary for a successful market start up. Parties have not raised any issue that threatens either the reliability or the successful start up of the energy market, or warrants a delay in starting the energy market, and therefore we deny rehearing.

76. Responding to Joint Cooperatives' concerns regarding the reallocation of functions between the Midwest ISO and control areas the TEMT II Order required the Midwest ISO and its control areas to negotiate "before a settlement judge the proper allocation of functional responsibilities, costs and liability associated with the Midwest ISO's new role in its region" and to make a filing presenting a proposed resolution.[74]

[74] TEMT II Order at P 126.

The Midwest ISO and the Midwest ISO TOs filed a Balancing Authority Settlement on October 5, 2004, and the Commission will consider that filing in a future order. As we stated in the TEMT II Order, it is critical that the division of reliability functions between the Midwest ISO and control areas be clear since without this clarity the ability of the Midwest ISO and control areas to respond effectively to reliability emergencies will be compromised. Accordingly, these issues must be resolved before market start-up.

77. Regarding the list of issues identified by the Joint Cooperatives as unresolved, each of those issues are continuing to be addressed. Although it would be preferable to have such issues resolved before market start-up, the TEMT II Order found that these issues are not critical to start-up and therefore the Commission appropriately deferred their consideration.

78. Regarding the issue raised by Consumers of changing control area responsibilities and the need for training, once we act on the pending Balancing Authority Settlement, we expect the Midwest ISO to have a training plan, and that it be communicated to control areas as soon as possible. We do not consider Commission proceedings to be the appropriate place to address verification of readiness by market participants, as Joint Cooperatives and Consumers suggest or to address the issues associated with the Readiness Advisor, as suggested by the Midwest Parties.[75] Rather, we encourage parties to use the stakeholder process and Midwest ISO committees to address readiness verification and related readiness issues. We consider the Midwest ISO testing plan to be the ultimate step in establishing market readiness,[76] and believe it will be very similar to the parallel run process proposed by the Midwest Parties.

79. We do not agree with LG&E that the Day 2 market will not be ready, and that further investigation is necessary. As we stated at the outset of the TEMT II Order, the Midwest ISO incorporates the major features used successfully in the three eastern ISOs and we are confident these features will be successful as applied to the Midwest ISO.[77] Contrary to LG&E's assertions, safeguards are a standard and prudent feature of new markets starting up and not an indication of an expectation that problems will occur. We

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[75] We note that the Midwest ISO has announced the designation of SAIC as the Readiness Advisor. SAIC made a presentation to the stakeholders at the October 20, 2004 Advisory Committee meeting.

[76] We note the Midwest ISO has announced a testing program informally and made a presentation to the Commission at its October 27, 2004 meeting.

[77] *See* TEMT II Order at P 2.

do not believe any benefit would be gained by holding hearings to develop safeguards, rather than utilizing safeguards already successfully implemented in the start up of other energy markets, nor has LG&E provided a basis for concluding otherwise. Finally, contrary to LG&E's claim, we have not stated that we expect price volatility at the start-up of the new market and we do not believe there is any basis to draw such a conclusion.

80. As we explained in the TEMT II Order, the purpose of the safeguards is to give the Midwest ISO sufficient experience with operating the market and to afford market participants experience with locational pricing, FTRs and other market features.[78] The purpose of the additional congestion hedge safeguard is to provide certain customers that could be highly exposed to congestion charges with transitional protection from the costs of congestion over a period of time sufficient to allow for investment in transmission and generation to alleviate that congestion. The purpose of the marginal loss transition safeguard is to allow market participants a period of time to see how this charge would affect their use of existing generation resources without significant cost shifts. Accordingly, the set of transition safeguards are measures to provide the system operators and market participants with room for learning and achieving an appropriate comfort level and to ameliorate potential cost shifts. For these reasons, we dismiss rehearing on these issues.

2. Transitional Limits on Supply Offers in the Energy Markets

a. Duration of Cost-Based Bidding

i. Background

81. The TEMT II Order required market participants to submit cost-based bids for generation resources to the day-ahead market, Reliability Assessment and Commitment (RAC) process[79] and real-time market for two months following the start of the Day 2

[78] *See id.* at P 35.

[79] The Midwest ISO will use the RAC process to ensure that sufficient generation is available to meet forecast load. The process is conducted following the close of the day-ahead energy market and will employ a security-constrained unit commitment dispatch algorithm to enable the Midwest ISO to select and commit any additional resources at minimum cost. Market Participants may voluntarily offer generation into this process and they may also be required, through the must-offer process, to offer capacity from Designated Resources that are not selected for the day-ahead market. *See* Module C, section 40.1, Original Sheet Nos. 530-38.

market.[80] The purpose of the cost-based bids is to afford the Midwest ISO and market participants with experience with the energy markets and congestion pricing during a period likely to reflect competitive market conditions.

ii. Requests for Rehearing

82. Midwest TDUs assert the cost-based bid safeguards should extend at least through the first summer, or until the Midwest ISO has demonstrated successful market performance and the Commission makes an affirmative finding. WPS Resources asserts cost-based bids need to continue until after a resource adequacy program consistent with the PJM program is filed and approved, metrics are completed and filed, critical path testing period, and grandfathered agreement issues are resolved, the initial FTR allocation is complete, control area functions are defined, allocated and tested, the cut-over process is developed and filed, and Business Practice Manuals are complete.

iii. Discussion

83. We clarify for parties that this safeguard is a Commission-imposed requirement that serves the sole purpose of ensuring a smooth market start-up. As such, it should be in place no longer than absolutely necessary. As we discuss below, we have no basis upon which to extend the term of the safeguard. We do not consider the safeguard to be another mitigation plan, as the Midwest TDUs propose. We believe the proposed mitigation measures to be the appropriate means to address those issues. With regard to WPS Resources' proposal, we believe their issues, with the exception of a permanent resource adequacy plan, will be resolved prior to the Midwest ISO's market start. In this regard, the LMP market can start successfully without the need for a completed resource adequacy program since the Midwest ISO has developed a transitional resource adequacy proposal and procedures to ensure adequate offers and bids will be made in the day-ahead market, real-time market and RAC process.

b. Applicability of Cost-Based Bidding

i. Requests for Rehearing

84. Dynegy requests the permissible elements of cost-based bids be clarified to specify that generators be allowed to fully recover all costs of start-up operations and minimum load requirements in addition to fixed costs, opportunity costs, and a risk premium for bids in the Day-Ahead market. Coalition MTC also request clarification on

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[80] TEMT II Order at P 63.

cost-based bids, including whether cost-based bids must reflect rates on file and approved by the Commission, the definition of the process for accepting cost-based rates for entities that do not have a Commission-approved cost-based tariff, whether cost-based bids should reflect marginal costs or marginal costs plus a contribution to fixed costs, whether opportunity costs must be considered, and what is the role of the IMM in the use of cost-based bids, during and after the two-month period.

ii. Discussion

85. Dynegy and Coalition MTC's arguments on rehearing address the pricing mechanism that will apply under this start-up safeguard. The Commission has ordered the Midwest ISO to make a further filing on this issue, and the mechanics of the pricing mechanism are now pending in the Midwest ISO's October 5 Compliance Filing. Dynegy and Coalition MTC's arguments are more properly raised in that proceeding.

86. In the TEMT II Order, the Commission found that market participants should submit cost-based bids for two months following the start of the Day 2 energy markets, and required the Midwest ISO to file "tariff sheets implementing this temporary transition LMP pricing plan. The tariff sheets should *describe the pricing mechanism* and designate a date upon which they will expire . . . ."[81] The Midwest ISO submitted a compliance filing on October 5, 2004, in response to this directive, and the Commission will address that filing in a future order. Dynegy and Coalition MTC have been given an opportunity to file comments to that filing (and they will also have an opportunity to seek rehearing of the Commission's order on that filing). We will therefore dismiss their rehearing arguments on this issue.

c. Feasibility of Cost-Based Bidding

i. Requests for Rehearing

87. Cinergy states that the application of cost-based bids will be infeasible for the large number of utility and merchant generators in its footprint – 1,150 – and will create potential for litigation and confusion. Cinergy also asserts this safeguard is inconsistent with the Commission's policy on market-based rates[82] since cost-based bids were

[81] *Id.* at P 63 (emphasis added).

[82] *See Market-Based Rates for Public Utilities*, 107 FERC ¶ 61,019 at P 1 (2004).

approved only to allow participants the opportunity to gain experience,[83] rather than to manage potential market power as required by Commission policy.

88. Further, Cinergy argues that this transition mechanism will delay the start of competitive Day 2 markets until at least May 1, 2005. It further states that the delayed timing of true market implementation could have the unfortunate consequence of providing price data that may confuse consumers and stakeholders in a way that is detrimental to the goal of competitive markets. Cinergy worries that because the cost-based period will take place during shoulder months, and the market-based phase will begin in the summer, higher seasonal prices will be mistaken for higher prices due to the introduction of market-based offers.

ii. Discussion

89. With respect to the feasibility of using cost-based bids at market start, we note that the Midwest ISO submitted a compliance filing on October 5, 2004, in response to our directive in the TEMT II Order to develop a temporary transition cost-based bidding plan, and the Commission will address that proposal in a future order. We note that, Cinergy has been given an opportunity to file comments and protests to the compliance filing, and it will also have an opportunity to seek rehearing of the Commission's order addressing that filing. We will therefore dismiss their rehearing arguments on this issue.

90. On the issue of switching from cost-based bids to market-based bids after the two month period, Cinergy has not presented any evidence that the transition will be unjust or unreasonable, and for this reason we dismiss rehearing on this issue. Inasmuch as prices typically increase in the summer, we do not consider the transition to market-based offers at the start of the summer period and the potential for higher prices to be inherently confusing to market participants. With respect to the perceived conflict between this requirement and the Commission's policies on market-based rate authority, we note that the proposed safeguard is a temporary and transitional safeguard only, and is not an indication that the Commission no longer supports market-based rates. As we explained in the TEMT II Order, we are not requiring this feature to manage potential market power. Rather, the purpose of using cost-based bidding is to provide a means to minimize the financial impact on market participants of any software failure; the individual exercise of market power will be mitigated through other means. We further note that while we are requiring cost-based bidding for this short period, generators will be receiving, and load will be paying, the price of the last cleared offer in the energy market and therefore the revenues received and paid could be different than a generator's

[83] TEMT II Order at P 63.

cost-based bid. That is, all infra-marginal units will get paid more than their marginal cost offer. Moreover, for the units on the margin that are rarely infra-marginal, if the market is competitive only during periods of scarcity could such units raise the market price. We are assuming that during the shoulder period, the market will be relatively competitive due to surplus capacity.

91. For this reason, we consider the safeguard a reasonable transition mechanism and we deny rehearing on this issue.

3. Transitional Safeguards for Exposure to Marginal Loss Charges

a. Background

92. In the TEMT II Order, the Commission required the Midwest ISO to calculate marginal loss charge components of LMPs, as it proposed, but to refund the surplus marginal loss charges to either the transmission customer's historical loss charge or an average loss charge.[84] This transitional loss refund method was made available to all existing transmission customers for a period of five years and to all new transmission customers for a period of one year from the start of the Day 2 markets.

b. Requests for Rehearing

93. PSEG requests rehearing on the marginal loss refund method and on its duration.[85] PSEG argues that the Commission has undermined its own goal of providing efficient price signals by eliminating the marginal loss charge impact. It argues further that virtual bidders will see only marginal loss prices and will be subject to paying marginal losses, while load serving entities and FTR holders will receive refunds based on the difference between marginal and average losses. PSEG argues that this could harm virtual bidding, which the Commission has recognized as being critical to the success of the LMP market because it allows greater price discovery, facilitates price convergence between the day-ahead and real-time markets, encourages trading and leads to a more liquid day-ahead market. PSEG requests that the Commission should modify its ruling to approve Midwest ISO's proposed marginal loss pricing and surplus refund rules or, in the alternative, to greatly reduce the transition period.

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[84] *Id.* at P 71-79.

[85] PSEG Request for Rehearing at 4, 10-11.

94. Midwest TDUs request clarification of the distinction between existing and new customers as it applies to eligibility for the transitional marginal loss refund.[86] Midwest TDUs would distinguish between customers that are existing Midwest ISO TOs, such as Lincoln Electric System, but are pending connectivity to the Midwest ISO system, and thus would be new transmission customers in the Day 2 market, and those that are truly new entrants into the Midwest ISO system.[87] Midwest TDUs request that the Commission clarify that the former, upon connection to the Midwest ISO system within the 5-year transition period, would be eligible for the marginal loss charge safeguard refund for the remainder of the transition period. For entrants that are truly new within the transition period and aware of the marginal loss pricing regime from the start, the one year transition would be applied.

c. Discussion

95. In response to PSEG, we stand by our ruling on the transitional marginal loss charge safeguard measure, for the reasons articulated in the TEMT II Order.[88] However, we do agree with PSEG that the transitional marginal loss refund method that the Midwest ISO adopts in compliance with the TEMT II Order should not disadvantage virtual bidders. We note that the transitional mechanism for implementing marginal loss pricing and refunds is at issue in the Midwest ISO's October 5 Compliance Filing and will be addressed in that proceeding.

96. We agree with the Midwest TDUs that the distinction between existing and "new" customers should be clarified, and that the concept of "new" customers should not include those parties with connectivity to the Midwest ISO system pending.

4. Transitional Safeguards for FTR Allocation

a. Background

97. In the TEMT II Order, the Commission found it appropriate to offer an expanded congestion cost hedge for five years to entities located in an NCA designated as such within six months from the start of the market.[89] We explained that entities in NCAs

[86] Midwest TDUs Request for Rehearing at 37-39.

[87] *Id.* at 37-38.

[88] *See* TEMT II Order at P 73-77.

[89] *Id.* at P 80-94.

could be highly dependent on existing firm transmission to generation resources outside the load pocket, and hence possibly subject to high congestion charges in the event that they did not hold sufficient FTRs. The expanded congestion cost hedge will hold them harmless with respect to the changes in the market design for their existing firm transmission contracts for a period of five years. Given Midwest ISO's flexible FTR nomination process, which could result in an oversubscription of the most congested lines, and hence result in some pro-rationing of nominated FTRs, the Commission found the expanded congestion cost hedge to be reasonable as a transition mechanism.[90]

98. Parties eligible for the expanded congestion cost hedge were required to abide by several rules including distinguishing between resources internal to the control area and the state and resources external to the control area and the state. Only FTRs from external sources are eligible for expanded congestion cost coverage, which will guarantee that the net congestion cost for these external sources is zero. If the FTRs for these external resources are insufficient to fully cover congestion charges, the expanded congestion cost hedge requires that the Midwest ISO will make up the deficit through an uplift charge.

b. Requests for Rehearing

99. FirstEnergy, Cinergy, DTE, Ameren, PSEG and LG&E argue that the congestion cost provision for NCAs is preferential and discriminatory because it singles out a particular class of market participant for superior rate treatment.[91] PSEG adds that WUMS Load-Serving Entities will receive an exclusive, superior congestion cost hedge, but that all administrative and uplift costs will be socialized among the Midwest ISO market participants. As such, all other Midwest ISO market participants will be forced to subsidize the WUMS Load-Serving Entities' failure to invest in grid infrastructure, and this is unduly discriminatory. PSEG states that since the Commission has not clearly set forth the rationale for the exemption, other parties may request the exemption after the six-month deadline; further, the exemption is antithetical to market development because

[90] *See* TEMT II Order at P 90 (citing *New England Power Pool and ISO New England, Inc.*, 101 FERC ¶ 61,344 (2002), which supported the use of transition mechanisms for pre-existing load pockets).

[91] FirstEnergy faults the Commission for not demonstrating that this accommodation was necessary by quantifying the adverse consequences FTR holders in NCAs would suffer in absence of the guarantee. Coalition MTC requests a more thorough determination of the potential uplift costs and impact on other market participants.

it sets up a non-market situation for WUMS Load-Serving Entities and any other qualifying NCA. LG&E states that, like the NCAs, it will not benefit from the energy markets so LG&E should also receive some form of special accommodation. Ameren states that it also relies on FTRs to import power to serve its load, but because it would not qualify as an NCA, the provision is inequitable.

100. Many parties allege that the NCA congestion cost provisions and the associated uplift charge will lead to subsidies and inefficiencies.[92] FirstEnergy contends that internal sources should not have to subsidize the congestion costs for external sources because it will cause inefficiency and discourage rational economic behavior. Ameren doubts the Commission's contention that the congestion cost hedge will not result in unreasonable cost shifts to parties not receiving such a hedge. DTE and PSEG add that there has been no demonstration that the provision is consistent with the principle of cost causation.[93]

101. Cinergy disagrees with the Commission's reliance on the NE Transmission Order in the TEMT II Order because in the NE Transmission Order, the Commission stated that it would be reasonable to moderate the impact of LMP on consumers as long as LMP price signals were not blunted. In addition, the Commission approved uplift of costs to construct transmission that would relieve congestion (*i.e.*, a structural remedy for a structural problem). Cinergy states that if the Commission is approving, in this proceeding, a footprint-wide uplift of congestion costs, it will blunt price signals and incentives to relieve congestion costs.[94]

102. Cinergy also claims that footprint-wide uplift would violate Commission orders that require localized uplift. Cinergy notes that the same Wisconsin parties wanting the expanded congestion cost hedge argued that they were discriminated against because their point-to-point transmission out of the ComEd zone was pro-rated to a greater degree

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[92] AMP-Ohio, DTE, LG&E, Exelon, Ameren and Cinergy oppose a footprint-wide uplift charge.

[93] LG&E and DTE assert that they should not be punished for the inaction of the NCAs to build sufficient generation.

[94] LG&E and DTE add that LMP is supposed to identify areas where investment is needed and provide market participants and regulators with this information, but the uplift will mute these price signals.

than network service to loads within PJM.[95] Cinergy states that the Commission directed PJM to assure that customers holding long-term firm point-to-point contracts are treated similarly in the FTR and Auction Revenue Rights (ARR) annual allocation process to network customers and ordered mitigation in the form of payment to the Wisconsin parties of congestion revenues for FTRs requested but not received with the costs of the uplift paid by the customers in ComEd's zone instead of over a broad region. Additionally, Cinergy asserts that the Commission has required localized uplift for RMR agreements because the costs represent the known (and short-term) costs of addressing congestion in specific regions during specific time periods and, therefore, should be reflected in the cost of energy in those regions.[96]

103. Additionally, FirstEnergy notes that the expanded congestion cost hedge lasts until 2010 which could adversely impact the Midwest ISO-PJM common and joint market which will be established in 2006.[97] Exelon seeks clarification that the NCA provision is not intended to override any PJM rules.[98] Further, Exelon states that it opposes the NCA uplift for insufficient FTRs revenues, but, as a member of PJM, it could accept this provision provided that under no circumstances will it be assessed any uplift charge, especially as a result of the hold harmless provision related to ComEd joining PJM.

104. The IMM states its concern that the efficiency of the real-time market may be impaired by the requirement in the TEMT II Order that entities in NCAs with additional congestion coverage have to schedule in the day-ahead market but are then subject to limits on the collection of congestion relief payments in the real-time market. The concern is that parties will prevent their generation from being dispatched efficiently to avoid such payment refunds. The IMM requests that the Commission clarify that any real-time provisions should not result in significant inefficiencies and that this objective

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[95] Cinergy Request for Rehearing at 14 (citing *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,223 (2004)).

[96] *Id.* at 17 (citing *New England Power Pool and ISO New England, Inc.*, 100 FERC ¶ 61,287 at P 58 (2002)).

[97] FirstEnergy Request for Rehearing at 7 & n.19.

[98] For example, if an entity voluntarily participates in the PJM capacity market with a resource, Exelon states that it must bid that resource into the PJM day-ahead market. If that entity wishes to be eligible to receive this expanded congestion cost hedge, Exelon states that it would not be able to do so and must delist its resources with PJM.

should take priority over the penalties for real-time deviations from the day-ahead schedule in the TEMT II Order. The IMM states that it should then take responsibility for identifying strategic behavior that the TEMT II Order was attempting to prevent through the use of automated market monitoring screens. The IMM would also monitor and report any over-scheduling day-ahead to the Commission.[99]

105. WEPCO and WUMS Load-Serving Entities seek rehearing on two of the eight conditions on the congestion cost relief in the TEMT II Order, which they claim adversely affect the coverage offered to recipients and the exposure of other parties to any resulting uplift.[100] First, they argue that the TEMT II Order's application of the coverage to resources "external to the control area and the state" will both exclude some resources for which the parties sought such coverage and also extend the coverage to parties that did not seek it. In the first instance, there is one WUMS entity with a resource outside WUMS but within the State of Wisconsin. There is concern that this party will not be eligible for the expanded coverage. In the second instance, there are several resources inside the NCA that are used to serve load outside the NCA in another state. The concern is that such resources will be eligible for additional congestion relief although they have not asked for it, thus leading to an increase in uplift charges generally. The rehearing request is to solve both these problems by modifying the scope of this condition to apply to network resources external to the NCA.

106. The second rule for which rehearing is requested requires parties seeking the additional congestion cost coverage to nominate FTRs equal to their total forecast peak load. WEPCO and WUMS Load-Serving Entities argue that this will require parties to accept FTRs that they do not want, for example, to intermediate and peaking resources located close to load and that this in turn could increase the uplift to other market participants. The rehearing request is to modify the scope of this condition to allow for flexibility in nomination.

107. WPPI argues that the duration of congestion cost relief for entities in NCAs (five years) is not sufficient to match the duration of WPPI's long-term generation resource commitments. WPPI argues further that the Commission erred by allowing the Midwest ISO to engage in actions that will diminish WPPI's existing rights and result in

[99] IMM Request for Clarification at 11-13.

[100] WEPCO at 7-10; WUMS Load Serving Entities at 4-11.

a disproportionate pro-rationing of FTRs awarded WPPI as compared to other utilities in the WUMS system. It seeks rehearing on more general hold harmless provisions for the FTR allocation, discussed in the FTR allocation section below.[101]

c. Discussion

108. In the TEMT II Order, we justified the transitional additional congestion cost protection for market participants in NCAs on the basis that such entities could be particularly exposed to high congestion costs if their FTR nominations were pro-rationed. NCAs are defined on the basis of the frequency of transmission constraints that limit imports, so those parties within NCAs that are highly dependent on external resources outside the NCA are likely to have much higher exposure to congestion charges than market participants outside NCAs. In addition, we restricted the additional coverage to parties with existing firm transmission service. We further noted that at least in part, the situation in which insufficient FTRs are available for allocation is due to the desire on the part of other market participants in the Midwest ISO market for flexibility in their own nomination of FTRs.

109. We disagree with intervenors that the application of this rule for prospective NCAs in the Midwest ISO is unduly preferential or discriminatory. In the Midwest ISO and in all other RTO and ISO markets, the Commission has approved different rules for NCAs in other aspects of market design, for example, in allowing different supply offer screening for purposes of market power mitigation inside and outside the NCA. The Commission's approval of such differences in the market rules is based on a reasoned assessment of the particular characteristics of those areas and the market conditions that entities within those areas face. These areas, quite simply, are not similarly situated to other areas.[102] Further, the congestion protection rules for NCAs are non-discriminatory because any entity finding itself in an NCA within six months of the start of the Day 2 market would be eligible for these protections. In response to PSEG's concern, we note

[101] WPPI at 7.

[102] The particular characteristics of concern in an NCA are that: (1) as we note in the preceding paragraph, transmission limits into the NCA mean that more expensive generation is needed to serve load for more hours of the year than outside the NCA, thus resulting in a higher locational price in the NCA than outside the NCA; and (2) the small number of suppliers in the NCA makes it potentially vulnerable to the exercise of market power. Our concern here is with characteristic (1), which would result in greater exposure to congestion charges in the event that sufficient FTRs are not available through allocation.

that the TEMT II Order made clear that this coverage was only available for NCAs designated as such within six months of the Day 2 market start.

110. We disagree with LG&E that it shares with market participants within NCAs the prospect that it will not benefit from the Day 2 markets, and that thus LG&E should also be eligible for a special accommodation. With regard to NCAs, we fully expect that for the many hours in which transmission constraints do not bind on the import paths into the NCA, the market participants within NCAs will benefit from the Midwest ISO markets. Hence, we do not find the assertion that some parties will not benefit to be a basis for a special accommodation.

111. In response to Exelon, we clarify that the additional coverage for NCAs is with respect to congestion charges assessed within the Midwest ISO market. Associated uplift, if any, will be assessed within the Midwest ISO market.

112. In response to LG&E and DTE, the additional congestion coverage will extend only to existing long-term firm transmission service. New requests for FTRs into the NCA will not be eligible for this coverage. In addition, the coverage is only temporary. Hence, it should not remove the price signal for entry of new generation within the NCA.

113. While we agree with Cinergy that to some extent, the enhanced congestion cost coverage will blunt short-term price signals to relieve congestion for those receiving the hedge, the protection is only temporary and the scope of the coverage is limited. We disagree with PSEG that the provision is antithetical to market development; rather, it provides entities within NCAs with an avenue to participation in regional markets during the period of time needed to address the infrastructure issues that contribute to high congestion costs in those areas. Also, we have in this order removed the penalties for deviations from the day-ahead schedule for those entities with the hedge, thus increasing the potential for an efficient dispatch. Moreover, as noted above, the protection is extended only to existing firm transmission service to resources outside the NCA; the locational price signal will impact all other power flowing into the NCA. Hence our decision is not inconsistent with the NE Transmission Order which provided only "one measure" to transition to LMP (*i.e.*, it did not preclude other measures from being appropriate), despite Cinergy's claim to the contrary.

114. We do not agree with Cinergy that the uplift associated with the enhanced congestion hedge should be localized in the NCA. First, one major reason why the NCA parties are more likely to be exposed to high congestion charges than other parties in the Midwest ISO is in part because of the flexibility in FTR nomination allowed those other parties. While the actual hedging properties of the FTRs made available through allocation will be made clear once the markets begin operations, and we anticipate that sufficient FTRs will be allocated (in which case, the additional congestion coverage will

not be needed), the likelihood of FTR revenue shortfall is greatest where congestion charges are highest and FTR pro-rationing is greatest. On the other hand, flexibility in nominating FTRs allows parties to maximize revenues from awarded FTRs. Hence, we believe that both the uplift associated with the enhanced congestion coverage and any uplift associated with the restoration of FTRs generally are reasonable uplift charges to support the added flexibility in nomination of base-load FTRs that are not restored under Tiers 1 and 2 and nomination of FTRs in Tiers 3 and 4. Second, the record of this proceeding does not contain information on the distribution of current redispatch costs to support existing transmission service and hence it would not be possible to allocate those costs on a continuing basis in the same fashion once the Day 2 markets begin. Third, given the uncertainty over current redispatch costs and future congestion costs, it is reasonable to allocate the transitional uplift broadly to mute its impact on any one party.

115. We do not agree with FirstEnergy that this provision of this hedge will adversely affect the joint and common market between Midwest ISO and PJM. Some of the existing firm transmission service that will receive the coverage does support purchases from within PJM. If the nominated FTRs from the Midwest ISO border to the sink points in the NCA that correspond to that existing service are fully allocated through the Midwest ISO FTR process, then the holders of those FTRs would be fully hedged and would have the same incentives to operate their external resources as would be the case if they receive the additional congestion cost coverage that we have offered.

116. We will grant the IMM's request for rehearing based on his concern that for parties receiving the expanded coverage, the penalties associated with deviating from the day-ahead schedule could result in an inefficient dispatch. We placed this limitation on the parties receiving expanded coverage as a means to prevent such parties from over-scheduling day-ahead to create congestion while being fully hedged against that congestion and then changing their positions in real-time to collect congestion relief payments. However, we do recognize that the limit we imposed in the TEMT II Order, the lower of 10 percent or 50 megawatts from the day-ahead schedule, could on occasion be too restrictive, and thus inhibit efficient changes in the day-ahead schedule. Hence, we will remove the scheduling restriction and instead require the IMM to file a monitoring plan to detect patterns of inefficient scheduling and associated mitigation measures, such as the refund of congestion relief payments that we required in the TEMT II Order.

117. We will grant the request for rehearing of WEPCO and WUMS Load Serving-Entities that the congestion cost coverage for external network resources is for such resources that are external to the NCA, rather than our original definition in the TEMT II Order that would require such resources to be external to the control area and the state. We accept their argument that our original definition would not achieve the objective of covering network resources external to the NCA. In addition, we clarify that this

congestion cost coverage does not extend to network resources within the NCA that are used to serve load outside the NCA.

118. We will also grant the request for rehearing of WEPCO and WUMS Load-Serving Entities of the requirement under the TEMT II Order that entities eligible for the congestion cost coverage must nominate the total FTRs associated with their forecast peak load. Our intention in the TEMT II Order was to make sure that, just as parties that have historically provided base-load counterflow could be required to accept counterflow FTRs in the restoration procedure, so parties accepting the expanded congestion coverage should not be able to withhold nominations of FTRs within the NCA that could assist in providing counterflow for allocation of FTRs from resources outside the NCA. We will accept, however, that the language in the TEMT II Order could be too stringent and could require parties within an NCA to nominate and accept FTRs from intermediate and peaking resources in the NCA that they do not want. Hence, we will change the nomination procedure to remove the mandatory nomination procedure, but require that in the restoration step, the Midwest ISO evaluate whether base-load FTRs within the NCA have not been nominated that would, were they restored, increase the allocation of FTRs for resources outside the NCA that are eligible for expanded congestion cost coverage. Midwest ISO would then restore any such "counterflow" FTRs in the restoration procedure, to ensure that any enhanced congestion cost coverage is minimized. That is, market participants inside NCAs will be treated like all other Midwest ISO market participants in the first two tiers of the FTR allocation.

119. We will deny WPPI's request for rehearing of the duration of the expanded congestion cost coverage. WPPI was a party to the WUMS Load-Serving Entities' request for such expanded coverage, which they collectively supported as a five year transitional mechanism while transmission and generation infrastructure within and around WUMS was expanded. Such investments in infrastructure will greatly improve the quantity of FTRs allocated annually as well as the ability to gain benefits from the Midwest ISO market.

5. Price Correction Authority in the Event of Temporary Market or System Operational Problems

a. Background

120. The TEMT II Order required the Midwest ISO to file rules providing for corrective measures in the event of temporary inability to calculate accurate market prices due to data errors, software errors, malfunction of ISO equipment, or outages of generation or transmission equipment, citing to the NYISO "Temporary Extraordinary Procedures" as an example of such rules. We required that such rules establish: (1) what types of system problems are being addressed; (2) circumstances under which the

Midwest ISO will invoke price corrections; (3) what the Midwest ISO will do to recalculate market prices; (4) when market participants will be notified of: (i) problems identified prior to market deadlines that could require price correction, (ii) problems identified after market clearing that will require price correction, and (iii) corrected prices; and (5) the process for addressing system problems that have caused the need for price corrections.[103]

b. Requests for Rehearing

121. Midwest ISO TOs consider upward adjustments under the price correction provisions to be retroactive ratemaking, allowable only under limited circumstances, such as calculation errors, and therefore request that Midwest ISO be directed to specify under what circumstances upward adjustments will be allowed and those circumstances should be limited to correction of calculation errors. Detroit Edison also requests clarification that the price correction authority be limited to computer modeling errors, and thereby clarify the meaning of "outages of generation or transmission equipment" in the TEMT II Order. LG&E expresses concern that after-the-fact adjustments should fall into a category that will not be considered retroactive ratemaking.

122. Ameren contends that any price-correction mechanism should be designed so that all parties to transactions subject to the original market prices are kept whole after the market price is adjusted, and that tariff provisions should set forth these mechanisms.

c. Discussion

123. We deny rehearing on this issue. As we explained in the TEMT II Order, we believe a price correction provision will benefit all parties by ensuring that they receive and pay just and reasonable prices, even in the event of market or system operational problems, and that we have approved this feature for other ISOs.[104] We required that the Midwest ISO develop and file rules for making corrections consistent with those

[103] *See* TEMT II Order at P 95-96.

[104] *See ISO New England, Inc.*, 108 FERC ¶ 61,069 (2004) (accepting proposed revisions to ISO-NE's Market Rule 1 that clarify procedures for correcting day-ahead markets). *See also* New York Independent System Operator, Inc., FERC Electric Tariff Original Volume No. 1, Attachment Q, "Temporary Extraordinary Procedures for Correcting Prices Resulting from Market Implementation Errors and Emergency System Conditions," Second Revised Sheet No. 641.

previously accepted for other ISOs.[105] We note that we directed the Midwest ISO to submit a compliance filing three months prior to market start, or December 1, 2004. Midwest ISO TOs, Detroit Edison, Ameren and LG&E have raised issues on how this feature should be structured and specified in the tariff. They will have an opportunity to file comments and protests to the compliance filing, and they will also have an opportunity to seek rehearing of the Commission's order addressing that filing. We will therefore dismiss their rehearing arguments on this issue.

C. Functional Responsibilities and Reliability

1. Background

124. In the TEMT II Order, the Commission found that it is "critical that the division of reliability functions between the Midwest ISO and control areas be clear."[106] The Commission found that the proposed TEMT properly used the NERC Functional Model as a basis for defining roles and responsibilities in the Day 2 markets. It added, however, that liability issues had arisen in the investigation of the August 14, 2003 blackout, and that it intended to fulfill the recommendations of that investigation. Accordingly, the Commission directed the Midwest ISO and stakeholders to participate in a settlement judge conference to address these and other issues.[107] The Commission further directed the Midwest ISO and stakeholders to return to the issue of control area consolidation, and to file a report on their progress toward consolidation within one year of energy market start-up.

2. Requests for Rehearing

125. Midwest ISO TOs assert the TEMT II Order did not respond to their protest regarding section 38.1.6.b and therefore request rehearing that the Midwest ISO's authority over reliability is constrained by contracts with Control Area Operators and authority granted by the NERC.

[105] *See* TEMT II Order at P 95-96.

[106] *Id.* at P 97.

[107] *Id.* at P 123.

126. Midwest Parties are concerned that "the very entities responsible for actually operating the grid do not know who is responsible for what."[108] They note that the TEMT II Order described the issue of allocation of functions as "critical to reliability."[109] Midwest Parties argue that negotiations requiring the proper allocation of functional responsibilities, costs and liability should have taken place before the Commission issued the TEMT II Order, and well before market implementation. They are concerned that the Commission has predetermined its acceptance of the results of the settlement negotiations because it did not tie the outcome of the negotiations to market implementation, and argue that it is illogical for the Commission to approve the TEMT while reliability functions remain unknown and subject to later approval. Midwest Parties reserve the right to challenge the results of those negotiations.

3. Discussion

127. In response to the Commission's requirement that affected parties negotiate the proper allocation of control area functions, costs and liability, the Midwest ISO TOs filed a settlement agreement on October 5, 2004. The Commission will act on this Offer of Settlement in a future order.[110] Therefore, we deny Midwest Parties' allegation that we have predetermined our acceptance of the Offer of Settlement as well as the Midwest ISO TOs' concerns regarding section 38.1.6.b. The acceptance of the relevant TEMT provisions remains subject to "refund, conditions, and further orders by the Commission."[111] The Commission thus retained the authority to reject these revisions to the TEMT if they remain unresolved, to modify the settlement or to order further proceedings to further address these issues. As we stated in the TEMT II Order, it is critical that the division of reliability functions between the Midwest ISO and control areas be clear since without this clarity the ability of the Midwest ISO and control areas to respond effectively to reliability emergencies will be compromised. Accordingly, these issues must be resolved before market start-up.

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[108] Midwest Parties Request for Rehearing at 12.

[109] *Id.* (quoting TEMT II Order at P 135).

[110] To consider the Offer of Settlement now would be premature, as the parties have been afforded 30 days to file comments and reply comments. *See* 18 C.F.R. § 385.602(f)(2) (2004).

[111] TEMT II Order at Ordering Paragraph (B).

D. Financial Transmission Rights and Locational Marginal Pricing

1. Background

128. This section of the TEMT II Order addressed the general methodology of the Midwest ISO's approach for initial allocation of FTRs. As the Order noted, the methodology approved by the Commission was a "compromise" between stakeholders that sought a certain level of mandatory FTR allocations based on historical uses and those that sought full flexibility in the ability of eligible entities to nominate FTRs between their eligible points of receipt and withdrawal. The compromise formulation was supported by the OMS. Of the stakeholders opposing the compromise formulation, Cinergy offered the most comprehensive alternative method of voluntary nomination. As stated in the TEMT II Order, the key compromise element accepted by the Commission was that while nominations for the first two tiers of FTR allocation, comprising up to 50 percent of the total eligible FTRs for a participant, would be voluntary, to the extent that a voluntary decision not to nominate FTRs from baseload generation resources within these tiers resulted in there not being counterflow available to support the simultaneous feasibility of other parties' nominated FTRs, then the former would be required to accept those FTRs that provided the counterflow. In a sense, then, the compromise was to move from a totally mandatory assignment of FTRs to a party regardless of whether other parties were positively affected by that assignment, to a mandatory assignment of FTRs to a party only in instances when it positively affected the FTR award to others for whom the party provided existing transmission service.

129. We also note that the TEMT II Order did not explicitly reject Cinergy's alternative proposal, but did so implicitly by accepting the proposed "compromise" method with some modifications.

2. Requests for Rehearing

130. Cinergy argues that the Commission's acceptance of the restoration procedure of assigning counter-flow FTRs was not the result of reasoned decision making and ignored evidence presented by Cinergy that it is unlawful.[112] The Commission also failed to address the expert testimony of Dr. Richard Tabors to that effect. Cinergy claims that the Commission statement in the TEMT II Order that the restoration procedure is the product of a compromise does not make it lawful. Cinergy states that the Commission's decision is required to be responsive to the evidence presented and to offer its own evidence to support its choice. Cinergy claims that the Commission has not done so.

[112] Cinergy at 6-13.

131. Cinergy states that the evidence it presented showed that the forced assignment of counter-flow FTRs will have real cost impacts on parties to whom they are allocated and this allocation proposal is unduly discriminatory, inefficient and unjust and unreasonable. Cinergy, and Dr. Tabors in his testimony, argue that the assignment of counter-flow FTRs will result in cost shifts because the holder of such FTRs will have an obligation to settle them financially whether or not it schedules the resources associated with the FTR sources in the Midwest ISO markets. Hence, the holder of the counter-flow FTR will take on a financial obligation as a means to provide another user of the transmission system with a congestion hedge. Dr. Tabors noted that this assignment of counterflow FTRs takes place despite there not being any contractual or economic basis for it. In addition, the party being assigned the counter-flow FTR is doing so on a non-voluntary basis, whereas the party accepting additional FTRs as a consequence can do so voluntarily. The assigned counter-flow FTRs will also distort FTR pricing and undermine FTR market liquidity. Moreover, the assignment of such rights is not necessary for the party seeking additional rights to hedge itself. Such market participants could seek additional FTRs through the monthly auctions.

132. Cinergy claims that its alternative proposal for a fully flexible allocation, in contrast, treats all existing transmission entitlements equally because no party eligible to nominate an FTR is required to take it. Cinergy's alternative proposal also meets the requirement of the simultaneous feasibility of the FTR allocation and allocates FTRs as obligations. This flexibility would give parties greater ability to manage congestion risk in the market as conditions unfold.

133. Cinergy states that the primary reason for implementing the counter-flow FTR proposal is to protect parties with native load obligations that could receive fewer FTRs than they anticipate based on historical usage if other parties can nominate flexibly, and that this is not justified, because the additional protections to the native load of such parties would come at the expense of other parties' native load. Cinergy argues that the Commission's precedent is not to assign priority to classes of transmission service, including native load, network and long-term firm service. Cinergy claims that neither the Midwest ISO nor the Commission offered a reasoned basis for departing from this Commission policy and adopting a preferential standard.

134. Midwest TDUs contend the TEMT II Order violates the Commission's hold harmless commitment[113] to parties highly dependent on existing transmission service outside high congestion load pockets, since there is no guarantee of FTR restoration, there is no assurance they will enjoy the protection promised by the Commission's White Paper, and there is no assurance sufficient FTRs will be available for the life of the existing resource commitment. The basis for the Midwest TDUs' FTR restoration concerns is that expanded restoration will have to be funded by resources required to provide counter flow, which may not be nominated and therefore available, resulting in pro-rationing. Midwest TDUs also repeat their preference that expanded restoration be funded through broad uplift, rather than counter flow provided by load-serving entities from existing resources.

135. Midwest TDUs argue additional FTR protection should be provided, if needed based on the results of the final FTR allocations due 90 days before market start, to ensure those holding existing long-term firm transmission rights are protected.

136. Midwest TDUs consider the FTR pro-rationing to be a regulatory taking since the effect of the LMP market is to replace economic rights to receive delivery of the energy that one injects with rights to receive more expensive market-clearing energy. To the extent this replacement is not beneficial to each affected entity, it is a regulatory taking, according to Midwest TDUs. Midwest TDUs state that taking property interests without just compensation is illegal,[114] and that compensation may be required for a non-physical, "regulatory" taking.[115] According to the Midwest TDUs, the TEMT interferes with

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[113] *See* Midwest TDUs Request for Rehearing at 13 (citing TEMT II Order at P 90 as the basis for this commitment: "Our decision to provide this additional coverage to entities in significantly congested load pockets stems from our intention to guarantee market participants that are highly dependent on existing firm transmission service and that are potentially subject to high congestion charges that they will receive sufficient FTRs or an equivalent financial hedge to hold them harmless with respect to changes in the market design.").

[114] *See Penn Central Transportation Co. v. New York City*, 438 U.S. 104, 123 (1978) (quoting *Armstrong v. United States*, 364 U.S. 40, 49 (1960)).

[115] *See Tahoe-Sierra Pres. Council, Inc. v. Tahoe Regional Planning Agency*, 535 U.S. 302, 332 (2002). *See also id*. at 341 ("a special burden that should be shared by the public as a whole"); *Nollan v. California Coastal Comm'n*, 483 U.S. 825, 835 & n.4 (1987).

investment backed expectations, a key factor in identifying compensable takings,[116] since load-serving entities sank investments that relied on the expectation[117] they would enjoy the economic value of having their own energy delivered to their loads whereas the TEMT will result in some committed-to resources ceasing to be economically viable.[118] Midwest TDUs states its expectation that particular existing resources will bear exceptionally heavy burdens to the point that their firm resource imports are rendered economically useless by unhedged congestion costs, and there is no basis to assume the LMP markets will provide substantially offsetting benefits. Finally, Midwest TDUs claim the Commission is obliged to provide an explanation of why existing sunk commitments of transmission customers should receive less protection than the Commission has provided in prior broad-scale restructurings, citing to the unbundling of pipeline transportation from natural gas sales, Order No. 888 and the transition to RTOs as examples.

137. WPPI states that the Commission erred in a number of ways in its support of the general FTR allocation methodology, which taken collectively would suggest that the Midwest ISO adopt a fundamentally different FTR allocation methodology. WPPI argues that the Commission erred by not requiring the award of full FTR coverage for WPPI's existing resources up to its annual peak load for the life of each existing resource and associated long-term firm transmission entitlement.[119] WPPI argues that the Commission erred by not requiring market participants to nominate their baseload and intermediate load resources in the first two tiers based upon historical use.[120] WPPI argues that the Commission erred by not providing it with full FTR coverage for all

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[116] *Penn Central* at 124. *See also Palazzolo v. Rhode Island*, 533 U.S. 606, 633-35 (2001) (O'Connor, J., concurring).

[117] Based on Order No. 888 OATT provisions that established durable transmission service commitments, predictable pricing of resource delivery, roll-over of long-term transmission commitments and planning requirements for transmission providers to keep resources as designated network resources.

[118] Further, Midwest TDUs argue that the right to deliver one's own energy is a distinct and recognized legal right that existed before the infringing regulation arose. *Compare Keystone Bituminous Coal Ass'n. v. DeBenedictis*, 480 U.S. 470 (1987) *with Pennsylvania Coal Co. v. Mahon*, 260 U.S. 393 (1922).

[119] WPPI Supplemental Request for Rehearing at 3.

[120] *Id.* at 3.

existing baseload and intermediate load resources if FTRs are nominated for such resources or alternatively to cap the amount of pro-rationing of FTRs for such resources at no more than 5 percent.[121] WPPI argues that the Commission erred by not requiring that the FTR allocation process treat firm transmission service no less favorably than grandfathered contractual transmission service.[122]

3. Discussion

138. We will deny Cinergy's request for rehearing of our decision to accept the FTR restoration procedure as part of the Midwest ISO initial FTR allocation, and its associated arguments that this procedure is unlawful and that our reasoning was not responsive to the evidence presented. First, the Commission had stated several times prior to issuing the TEMT II Order what its principles were for FTR allocation. As restated in that order, we stressed that customers under existing transmission contracts should continue to receive the same level and quality of service. We also noted that FTR allocation should be based on historical uses of the system.[123] In other markets, stakeholders have agreed to other principles for allocation (of FTRs or FTR auction revenues), but only because they felt that such principles would lead to a reasonable outcome. In the Midwest ISO market, the primary alternative proposal, for full voluntary nomination, set forth by Cinergy, did not reflect our clearly stated principles. The TEMT II Order explicitly stated "that if market participants could nominate flexibly, they would naturally seek the most valuable rights rather than ones that reflect historical uses of the system."[124] In other words, flexible nomination conflicts with the principles we had articulated. However, what the Midwest ISO described as a "compromise proposal"[125] did reflect our principles and had the added benefit of allowing flexible nomination as long as it did not excessively deprive other market participants of their nominated FTRs. As we stated, "with some additional safeguards, our objectives and principles for the FTR allocation

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[121] *Id.*.

[122] *Id.* at 4.

[123] TEMT II Order at P 156.

[124] *Id.* at 156.

[125] Midwest ISO Transmittal Letter at 15, Docket No. ER04-691-000 (March 31, 2004). The Commission's reference to this proposal in the TEMT II Order as a "compromise" merely echoed the Midwest ISO's description; it was not, as Cinergy alleges, intended to lend legal justification.

can be achieved through the proposed Midwest ISO methodology."[126] The TEMT II Order did not explicitly reject the Cinergy proposal, but its rejection was clearly implicit in our observation "that if market participants could nominate flexibly, they would naturally seek the most valuable rights rather than ones that reflect historical uses of the system."[127]

139. We agree that full voluntary nomination of FTRs would be preferable to mandatory assignment under the restoration procedure if voluntary nomination did not conflict with our principles stated above. Indeed, the restoration procedure is a transitional measure, to be followed by voluntary nomination. The transition will allow market participants to understand over a reasonable period of time what level of FTRs they actually need as a congestion hedge, to develop additional congestion hedges and to make investments where possible to reduce congestion. The Cinergy proposal would deny them that learning experience, requiring them to compete at the start with other parties for the most valuable FTRs and have an uncertain exposure to congestion charges if they fail to guess properly or fail to get sufficient awards of FTRs. We have stated before, and state again, that this would not be just and reasonable.

140. We will deny Midwest TDUs request for rehearing that the TEMT II Order violates the Commission's hold harmless commitment. First, we believe that through the combination of the Midwest ISO's proposed methodology for FTR allocation and the enhancements of that methodology that we required in the TEMT II Order, all parties in the Midwest ISO markets will receive sufficient FTRs to hedge congestion charges such that net congestion charges will be comparable with the costs of redispatch and costs of curtailments due to TLRs associated with their existing transmission service. The quality of transmission service should also increase, since TLRs will be substantially reduced. In that order, we provided additional protections to parties within load pockets for a five year transition period. Outside load pockets, we expanded the FTR restoration to five years and increased the eligibility of resources for FTRs. As we stated above, the transition period for FTR restoration will allow Midwest TDUs to learn about their actual needs for financial hedges without full exposure to a flexible FTR allocation scheme.

141. Midwest TDUs request assurance of the protections that they seek. Our preference in the TEMT II Order was for *ex ante* protections rather than *ex post* true-ups. The reason for this is that *ex post* make whole payments that are not tied explicitly to efficient behavior (such as daily bid revenue sufficiency guarantees that allow parties to

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[126] TEMT II Order at P 156.

[127] *Id.*

offer supply at true marginal cost) are very likely to inhibit efficient behavior, because the make-whole payment removes the consequences of inefficient scheduling. We believe that the *ex ante* measures, on the other hand, provide assurance of a high degree of protection and require attention to efficient use of generation and transmission.

142. In addition, we do not agree with Midwest TDUs that it is necessary to guarantee that an exact amount of FTRs will be allocated for the life of the existing transmission service contract, and that otherwise the parties are subject to a regulatory taking and interference with investment-backed expectations. We believe that such a guarantee would be discriminatory unless all market participants in the Midwest ISO region could receive the same guarantee. Furthermore, if such a guarantee were offered to all market participants, it would work at cross-purposes with the regulatory reform that is underway. The purpose of open access, spot energy markets and price-based congestion management is to improve transmission access, increase the scope and efficiency of short-term purchases of power (daily, hourly) through competition, thereby reducing the costs of redispatch and improve the quality of transmission service by greatly reducing TLRs. The type of guarantee that the Midwest TDUs request would go in the opposite direction: requiring the Commission and the Midwest ISO to develop elaborate pricing and financial settlement schemes that suppress market competition and shift uplift charges in complex ways around the system. This would be for two main reasons. First, the megawatts covered by financial hedges (FTRs) do not need to be in one-to-one correspondence to the megawatts covered in physical contracts for transmission service for there to be a full financial hedge. Awarding full FTR coverage would require uplift shifted to other market participants, and further, without additional market rules, it could allow some market participants with such full coverage to retain surplus FTR revenues even while others pay uplift to support the full coverage. For fairness, that surplus would have to be recovered by the Midwest ISO and returned to other parties being charged uplift. Second, it would be inappropriate to offer financial guarantees with respect to congestion costs that require shifting uplift costs to others, but then let market participants with those guarantees retain benefits from the LMP energy markets (such as when they purchase from the spot market rather than operate a more expensive resource). There will be many occasions when a net positive congestion charge over some period (that is, after FTR revenues) is more than offset by energy market benefits. Hence, the Midwest ISO would have to calculate and then reclaim these energy market benefits to offset the uplift charges.

143. Returning to the Midwest TDUs' argument: As a corollary to our concern that meeting their objective of guaranteeing the allocation of an exact amount of FTRs per transmission service contract would be discriminatory, we reject their concern about regulatory takings and investment-backed expectations. We have approved the FTR provisions of the tariff as just and reasonable, and what is just and reasonable is not a

taking.[128] "[T]he Commission's action in this proceeding – ensuring that ratepayers are not charged an excessive, unjust and unreasonable rate – is not an unconstitutional taking, even though it may produce a rate less than the rate [applicants] would like to charge."[129] Moreover, the TDUs' argument that they will lose economic value in their investments is speculative, since the final FTR allocation has not been made for the first period of market operations, nor have sales been made or power flowed under the TEMT. When that allocation is made, it will be much clearer which parties are at risk, if any. We will require the Midwest ISO to make known to parties that receive "restored" FTRs how many counterflow FTRs were assigned for such restoration. Accordingly, we directed the Midwest ISO to make informational filings 30 days after each annual FTR allocation. This will provide those parties, over the five years of the restoration period, important information on how much FTR exposure would be likely under a flexible nomination method. If serious shortfalls in congestion hedges without compensating benefits from the energy markets emerge for parties during the transition period and after, they can file with the Commission to change the market rules.

E. Other Issues Related to the FTR Allocation Process

1. General Background

144. This section of the TEMT II Order addressed a number of specific issues in the FTR allocation process that were not considered to pertain to the overall structure of the process but rather to refinements of it. We addressed four categories of issues: first, whether the FTR conversion rules fairly accommodate various types of existing transmission service and current transmission reservation requirements; second, how to consider particular types of contracts or resources that may be difficult to represent adequately in FTR nominations; third, details of the proposed rules that determine eligibility for restoration and the duration of the restoration procedure; and fourth,

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[128] *See, e.g.*, *FPC v. Texaco Inc., et al.*, 417 U.S. 380, 391-92 (1974) ("All that is protected against, in a constitutional sense, is that the rates being fixed by the Commission be higher than a confiscatory level."); *Permian Basin Area Rate Cases*, 390 U.S. 747, 770 (1968) ("[A]ny rate selected by the Commission from the broad zone of reasonableness permitted by the [Natural Gas] Act cannot properly be attacked as confiscatory."); *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 600-01 (1944) ("The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact that the value is reduced does not mean that the regulation is invalid.").

[129] Southern Company Services, Inc., 57 FERC ¶ 61,093 (1991).

additional measures in the specification of FTRs and the sequencing of the annual FTR allocation that would improve the coverage of awarded FTRs. We address issues in these categories on rehearing in the order of the categories presented in the TEMT II Order.

2. Requests for Rehearing

a. FTR Specification for Existing Point-to-Point Transmission Service

i. Requests for Rehearing

145. Ameren argues that for conversion of existing point-to-point transmission service to FTRs, where the point of receipts are a control area, the Midwest ISO TEMT improperly uses generation commercial nodes in the control area as default source points. Ameren argues that some point-to-point contracts are not linked to capacity purchases from generators in the control area, and that for such contracts, when Midwest ISO cannot determine the appropriate set of receipt nodes, the default entitlements should be the load buses (load zone). Ameren argues further that in general by sourcing control area FTRs at a set of generator buses, Midwest ISO may "over-inject" from those generators, resulting in a reduction in the FTRs that can be awarded to the load-serving entity at those locations.

146. Cinergy makes a similar argument in its protest, stating that where there is no agreement as to the FTR receipt point definition, the existing entitlement sources should be defined based on a pro-rata share of each generation commercial node in the originating control areas. Also, Cinergy asserts that absent agreement, the Midwest ISO should use a default source of the load zone within the control area. Cinergy concludes that this approach is preferred since it more closely approximates the methods used by the Midwest ISO to calculate available flowgate capacity and in granting transmission service.

ii. Discussion

147. We find that Ameren's and Cinergy's requests for designating the FTR receipt points in a point-to-point contract where the receipt point is a control area using the set of load nodes as the default when the contract does not designate generators as the set of capacity resources does not have adequate support. We interpret the Midwest ISO tariff accepted in the TEMT II Order as offering the use of load buses as designated receipt points as an option, and thus open to request by Ameren and Cinergy, but do not understand why it should be the default in the case presented by Ameren and Cinergy. We would also expect the Midwest ISO to take any problem of artificially "over-injecting" through the use of generator buses as control area receipt points into account,

and ensure that if appropriate load buses are available that allow for additional FTRs while respecting simultaneous feasibility they would be used. Again, this problem, if it exists, was not presented by Ameren or Cinergy with adequate support.

b. Priority of Shorter- Versus Longer-Term Rights of Annual or Greater Duration

i. Background and Requests for Rehearing

148. In the TEMT II Order, the Commission affirmed that all transmission service of annual or greater length would have comparable treatment in the allocation of FTRs. WPPI argues that the Commission erred by not extending a priority to long-term, multi-year transmission service over annual rights with roll-over rights.[130]

ii. Discussion

149. We disagree with WPPI that we erred by not granting annual rights with roll-over rights a lower priority for FTR awards than longer-term rights. As we stated in the TEMT II Order, we have long held that all firm service has the same priority and that all long-term firm service is treated equally, regardless of length of term.[131] The Commission has required utilities to plan for one-year contracts with right-of-first-refusal rights as if the contracts would be on the system indefinitely. Accordingly, we will grant no FTR preference between long-term contracts based on contract duration should a *pro rata* allocation become necessary.

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[130] WPPI Supplemental Request for Rehearing at 3-4.

[131] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part, remanded in part sub nom.* Transmission Access Policy Study Group, *et al.* v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

c. FTR Eligibility for Holders of Network Service Contracts with Short-Term Network Resource Designations

i. Background

150. In the TEMT II Order, the Commission stated that:

> In *PJM Interconnection, L.L.C.*, we affirmed that long-term existing rights, of duration of one year or more, have priority over short term monthly or seasonal rights in the annual allocation of FTRs (or ARRs)… This reflects the reasonable expectation of long-term customers that they will retain their transmission service. We will thus reject EPSA, Detroit Edison and Dominion's requests for equal priority in the allocation to customers with less than annual existing service. The Midwest ISO FTR market offers opportunities for obtaining congestion hedges subsequent to the FTR allocation through the monthly and annual FTR auctions and for being granted ARRs for load in retail choice states. The Commission has, since Order No. 888, made clear that all firm service has the same priority and, specifically, that all long-term firm service is treated equally, regardless of length of term…[132]

Accordingly, the TEMT II Order affirmed that long-term existing rights (of one year or more) have priority over short-term or seasonal rights in the annual FTR allocation process.

ii. Requests for Rehearing

151. Constellation, Coalition MTC, Detroit Edison, OMS and WPS Resources seek clarification, or alternatively rehearing, over the eligibility for FTR allocation of Network Integration Transmission Service (network service) of annual or greater duration but under which particular network resources are used with duration of less than one year.[133]

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[132] TEMT II Order at P 182.

[133] Constellation Request for Rehearing at 2-11; Coalition MTC Request for Rehearing at 17-22; Detroit Edison Request for Rehearing; OMS Request for Rehearing and WPS Resources Request for Rehearing.

These parties are concerned that Midwest ISO is planning to interpret the TEMT II Order as not permitting such network service usage for FTR eligibility. That is, the parties claim that Midwest ISO will require customers with NITS also to hold designated network resources for the 12-month period of the annual FTR allocation for eligibility.

152. OMS asks the Commission to clarify paragraph 182 of the TEMT II Order, which affirmed that long-term existing rights (of one year or more) have priority over short-term monthly or seasonal rights in the annual allocation of FTRs. OMS indicates that while it generally agrees with this policy, it is concerned with the application of the policy to contracts or arrangements that are seasonal in nature but still reflect long-term customers' reasonable expectation that they will retain their transmission service. It provides two examples of how the policy might be detrimental as applied.

153. OMS asks the Commission to separate the concept of long-term transmission service from the concept of annual designation of network resources, and to recognize that seasonally-designated network resources for network service can be contracted for a multi-year period. While OMS suggests that the Commission continue to support priority for long-term existing transmission rights over short-term rights in the annual FTR allocation, it also thinks that the Commission should expand the concept of long-term existing transmission rights to include monthly or seasonal designated resources for which the customer has obtained transmission rights for a multi-year period. OMS argues that the Commission should consider the expected use of contracted generation services. It states that facing the risks of purchasing congestion hedges on a year-to-year or month-to-month basis will be a significant barrier to entering into long-term contracts for seasonal capacity and energy and will penalize load-serving entities that are more dependent on generation contracts to serve their loads.

154. Constellation points out that the PJM Order cited in the TEMT II Order referred to priority in the FTR allocation of long-term point-to-point transmission customers over short-term point-to-point customers, and is thus not relevant to customers with network service.[134] Constellation cites Commission precedent giving network service with short-term designation of network resources priority over short-term point-to-point service of the same duration.[135]

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[134] Constellation Request for Rehearing at 7 (citing *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,223 (2004)).

[135] *Id.* at 8.

155. Constellation states that the use of a combination of network resources of less than annual duration under network service is long-standing practice throughout the Midwest ISO region. OMS similarly points out two types of existing transmission users with long-term service that might be adversely affected. The first is a seasonal contract between a vertically integrated utility and an IPP for summer peak power. The utility takes network service for the power contract for the entire year, but some capacity from the IPP is only classified as a network resource for the summer months. The second is a contractual arrangement between two utilities that seeks to make efficient use of seasonal diversity.

156. These parties request that the Commission clarify that the TEMT II Order did not intend to deny allocated FTRs to long-term network service customers that use a portfolio of resources, each with a duration of less than one year.

iii. Discussion

157. We clarify that we did not intend for parties with annual network service to be disqualified from the initial FTR allocation because some of the network resources scheduled under such network service are used with a duration of less than one year. We understand that many parties in the Midwest ISO have annual network service that supports a portfolio of owned or contracted generation and that some of those generators are used seasonally with the expectation of continued long-term service. To that extent, those generators can be nominated as source points for FTRs, but in keeping with the current FTR allocation methodology, only base-load generation would be eligible for restoration under the conditions that we required in the TEMT II Order. In addition, seasonal network resources with annual network service should only be eligible for seasonal (or monthly) FTRs corresponding to the season (or months) in which the resource is dispatched historically.

d. FTRs for System Purchases

i. Background

158. In the TEMT II Order, the Commission rejected a request by Midwest TDUs that sellers of system purchase contracts be required to share congestion costs with the buyer under the contract.[136] System purchases are typically mapped into FTR allocations through a "zonal" FTR that assigns each generator serving the system purchase a

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[136] TEMT II Order at P 182.

weighted share of the total megawatts under the purchase. The Commission required that the Midwest ISO offer the "redirect" option for such zonal FTR requests that the Commission approved for PJM.[137]

ii. Requests for Rehearing

159. Midwest TDUs argue that the TEMT II Order offers unclear relief that falls short of what is needed to protect system purchases.[138] They further argue that while the Commission addressed one of the options they proposed, it rejected it without explanation, and it did not address two others. The first of these was that the Commission establish a presumption that unless otherwise specified in a system purchase contract, the supplier should have the obligation to select and nominate for FTRs to cover the purchase and hold the customer harmless for any additional unhedged congestion associated with the purchase. The second of these was that the Commission establish procedures to establish weighted Aggregated Price Nodes[139] and a presumption of dispatch comparability. Each of these options is intended to minimize the possibility that the seller of the system purchase would sell from generators that would shift congestion costs to the holder of the contract, who might be unhedged if the allocated FTRs (if nominated by the holder of the contract) are not matched to the generators actually used. Midwest TDUs request that the Commission grant rehearing to expand or clarify the relief ordered.

160. Midwest TDUs make two main arguments in support of the request for rehearing. First, they note that the redirect option supported by the Commission in the TEMT II Order was designed for point-to-point service and not for the network service that largely characterizes system purchases in the Midwest. LG&E makes a similar point.[140] Second, they argue that because system purchasers cannot control the dispatch of the generators that serve them, and hence cannot match the dispatch to a set of allocated FTRs, they cannot effectively manage congestion exposure. They argue that to receive the same level and quality of service, suppliers under system purchases must be subject to a

[137] *See PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,223 at 16 (2004).

[138] Midwest TDUs at 33-37.

[139] An Aggregated Price Node is "[a]n aggregation of Price Nodes whose LMP is calculated as a specific weighted average of the LMPs in the constituent Price Nodes." Module A, section 1.7, Original Sheet No. 48.

[140] LG&E at 25.

presumption that they will bear the costs of congestion associated with generators that they control or that they will at least treat system purchasers comparably in dispatch. Another method for comparable treatment suggested by Midwest TDUs is to require a supplier under a system purchase contract with a fuel-adjustment clause to offer to flow through the fuel-adjustment clause the same allocated share of both the congestion revenues and congestion charges associated with all resources that are used to supply any system sale. The purchaser would be subject only to such congestion charges. If the system purchase does not have a fuel-adjustment clause, then the customer should be given the option to accept a pass-through of its load-ratio share of congestion revenues and charges, in lieu of taking its chances of FTRs providing a sufficient congestion hedge. Midwest TDUs note that under either of these options, the purchaser's FTRs would be pooled with the supplier's other customers.

iii. Discussion

161. We will grant Midwest TDUs' request for rehearing on the allocation of FTRs for existing transmission service that supports system purchases. In other markets transitioning to LMP and FTRs, the existence of such contracts resulted in similar commercial issues between buyers and sellers. In PJM and New England, the issues were treated as commercial matters between the contract parties who had agreed to such contract terms and were resolved without Commission intervention. More recently, in California, certain existing "seller's choice" contracts with similar properties to system purchases, in terms of the seller's ability to designate delivery points for the power, have been set for hearing before an ALJ.[141]

162. We would prefer that in the Midwest ISO, parties to such contracts are able to come to an accommodation on the assignment of FTRs and taking of congestion risk on a commercial basis. We encourage them to do so for the next round of FTR allocations. However, because there is not sufficient time prior to nominations for the initial FTR

[141] In a recent order on the CAISO's market redesign proposal, the Commission noted that the disposition of such contracts is a commercial issue and encouraged the parties to find a resolution. *See California Independent System Operator Corporation*, 105 FERC ¶ 61,140 at P 51-60 (2004). In a further order in that proceeding, the Commission addressed the issue again, repeating that these contracts are a commercial issue, but instituting a section 206 proceeding and setting them for hearing before an ALJ. *See California Independent System Operator Corporation*, 107 FERC ¶ 61,274 at P 165-66 (2004) ("[T]he ALJ should explore with the parties and the CAISO the viability of creating a trading hub or other commercial solution as a means of addressing the issues presented by the sellers' choice contracts."). That proceeding is ongoing.

allocation, we will adopt an alternative approach and require the seller of the existing transmission service to nominate and hold the FTRs as well as be responsible for congestion charges associated with delivery of the system purchase. Under this approach, the party originally responsible for the risk of congestion remains responsible under the energy markets, until such time as an alternative solution can be agreed upon as discussed below.

163. We will clarify that, as suggested in the TEMT II Order, the Midwest ISO must make available pricing zones or hubs for specification of FTRs to support system purchases, if that is not already the case. Second, as we stated in the TEMT II Order, we agree with the Midwest TDUs that alternative methods to the allocation of the FTRs will matter when converting existing combined contingent energy contracts, such as system purchases in which the seller determines from which resources to supply power, and transmission service contracts to support such contracts, typically network service. The properties of such contingent energy contracts when combined with existing transmission contracts make them different from converting transmission service to specific generation resources or a portfolio of network resources owned or under contract to the buyer of transmission service. We will clarify our views here.

164. Among the alternative methods for converting such joint energy and transmission contracts to FTRs, three stand out (others, such as those discussed by the Midwest TDUs are also possible). First, the seller of the system purchase and the existing transmission service could be required to nominate and hold FTRs from a fixed set of receipt points and would be charged any congestion costs associated with delivery of power under the contract. The buyer of energy and transmission would not hold FTRs nor pay congestion charges. Second, the buyer of energy and transmission service could be required to convert the transmission service to FTRs from a fixed set of receipt points corresponding to generation sources to its load and would be charged for congestion. Third, the buyer and seller could define a set of locations to serve as a fixed hub or zone for delivery. The seller of the system purchase could nominate and hold FTRs from the source generators to that hub or zone, and be responsible for any associated congestion costs, while the buyer could nominate and hold FTRs from the hub or zone to the load, and likewise be responsible for any associated congestion costs. This latter method is essentially what Midwest TDUs have requested.

165. We agree with Midwest TDUs that the second option cannot support a reasonable mapping of existing contingent energy purchases and supporting transmission contracts into FTRs. While FTRs do not have to match physical deliveries to provide sufficient congestion hedges, it should be the entity that can schedule the generation that should choose how to specify the source points. This is because once an FTR has been awarded, it is a fundamental property of such rights that by following the specification of the FTR – that is, the megawatts injected and withdrawn at the locations – the holder of the FTR

can hedge itself against congestion charges. This property would not be present with a contingent energy purchase, such as a system purchase, if the buyer were required to hold the FTR but does not control the supply resources designated as points of receipt.

166. While both methods one and three (and others that achieve the same ends) are reasonable ways to assign transmission rights and congestion costs in support of system purchases, given the limited time available for preparation for the initial FTR allocation we will require buyers and sellers of system contracts whose contracts currently assign redispatch costs to adopt our method one. That is, the seller of the existing transmission service that supports the system purchase must nominate and hold FTRs corresponding to the system purchase and pay all congestion costs associated with delivery of power under the contract. This method is reasonable because the entity scheduling the resources also holds the FTRs and can thus manage its own congestion cost exposure. We encourage buyers and sellers of system purchases to examine and agree to other approaches, such as method three, for the Commission's consideration prior to the next round of FTR allocation.

e. FTRs for Pumped Storage

i. Background

167. In the TEMT II Order, the Commission agreed with Detroit Edison that pumped storage units with physical transmission rights that currently cover usage patterns as described by Detroit Edison would present a challenge when converted to financial rights and that FTR options or flowgate rights could be more beneficial. The Commission asked for more detail on Detroit Edison's issue in that order.[142] In the GFA Order, reflecting the unique rights, responsibilities of the contract and the unique operational characteristics of the pumped storage facility, the Commission carved out the pumped storage GFAs from the energy market and required that Detroit Edison and Consumers submit day-ahead and modified real-time schedules to the Midwest ISO. With respect to the allocation of Schedule 16 and 17 costs, the GFA Order assessed only the Schedule 17 charge on Detroit Edison for its pumped storage injections into the transmission system during the generation mode.[143]

[142] *See* TEMT II Order at P 185.

[143] *See* GFA Order at P 185, 299.

ii. Requests for Rehearing

168. Detroit Edison renews its request for bi-directional FTRs, clarifying that it is requesting 24 hour coverage of transmission to and from the Ludington pumped storage unit in the form of options, rather than obligations.

169. Detroit Edison argues that the TEMT II Order did not address two issues it raised regarding imposition of Schedule 16 and 17 charges on pumped storage units. It requests rehearing or clarification that: (1) Schedule 17 charges will only be assessed when operating in a generating mode; and (2) the operator of a pumped-storage unit will only be charged under Schedule 16 in one direction at a time. With regard to its first concern, Detroit Edison is concerned that pumped storage facilities could be double-charged under Schedules 10 and 17 – that is, pumped storage facilities could be charged for injections and withdrawals for both pumping and generation. It argues that this would impose an excessive burden on operators of pumped-storage facilities.

170. As for its second concern, Detroit Edison argues that Schedule 16 charges raise the prospect of double-charging pumped-storage units because such charges are imposed based on FTR allocations, not FTR usage. Detroit Edison avers that if pumped-storage facilities are afforded bi-directional FTR allocations, operators of the FTRs would not be able to take advantage of those allocations in both directions because the operator will not operate the facility in pumping and generating mode simultaneously. In such a situation, if Schedule 16 charges were based on FTR allocations rather than usage, then the operator of a pumped storage facility would pay Schedule 16 charges for FTRs that it did not use but had to have to take full advantage of the facility's unique attributes. Detroit Edison says that this double-charging would discriminate against "the mere nature of pumped storage" and discourage use of such facilities. To remedy the potential overcharging, Detroit Edison seeks clarification that as long as the operator of a pumped-storage facility does not operate the facility in both pumping and generating mode in the same hour, the operator will not incur Schedule 16 charges in both directions for that hour.

iii. Discussion

171. In light of the GFA Order, both of Detroit Edison's arguments regarding the application of Schedule 16 and 17 charges to pumped-storage facilities are moot. In the GFA Order, the Commission ordered the Midwest ISO to carve out of the energy markets Detroit Edison's GFAs involving the Ludington Hydroelectric Pumped Storage Plant.[144]

[144] *See id.* at P 185.

The parties to carved-out GFAs will not receive FTRs and therefore will not be assessed Schedule 16 charges.[145]

172. The Commission also clarified in the GFA Order that Detroit Edison should be assessed the Schedule 17 charge only on its pumped storage facility's injections into the transmission system:

> Since the extractions from the transmission system occurring when the facility is in pumping mode, are not to serve load in the traditional sense, such extractions from the transmission system should not be assessed the charge. By charging the pumped storage facility only when it is in generation mode, the pumped storage facility will be placed on the same footing as other generation.[146]

173. Detroit Edison's concern about the proper application of Schedule 17 charges to its pumped-storage facilities is therefore moot. As indicated in our GFA Order, we have carved out the pumped storage GFAs and therefore Detroit Edison will not be receiving FTRs for these contracts during the transition period. Accordingly, for market start-up and through the transition period, Detroit Edison's request for rehearing is moot. Detroit Edison is free to renew its request for FTR options after this period expires in future proceedings.

f. Duration of FTR Restoration

i. Background

174. In the TEMT II Order, the Commission modified the proposed duration of the FTR restoration step following the second tier of the initial allocation, extending it from three years, as proposed by the Midwest ISO, to five years. The Commission noted that sufficient time was needed to gain experience with LMP pricing and to allow for adjustment to the LMP and FTR systems. The Commission further noted that it did not consider providing restoration for more than five years out of concern that such coverage could then delay needed investments to expand the transfer capability of congested transmission facilities.

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[145] *See id.* at P 295.

[146] *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,235 (2004).

ii. Requests for Rehearing

175. The Midwest TDUs seek rehearing of the Commission determination that the FTR restoration process will be terminated after 5 years. They assert that historical firm uses should be preserved through FTRs, until those historical uses terminate of their own accord. They note that the TEMT II order did extend the restoration period by 2 years, but the Midwest TDUs argue that this extension does not go far enough because many long-term power supply contracts last beyond 5 years and getting additional resources built generally takes longer than 5 years. Furthermore, they argue that removing the FTR restoration after 5 years is counter to the Midwest ISO's express obligation in the tariff to ensure that the grid is planned and developed for Network Customers, their load growth, and their designated and planned generation. They argue that their fears of insufficient FTRs to cover historical use in 5 years are justified because the Midwest ISO has not produced a grid capable of simultaneously meeting today's firm demands, let alone feasible delivery of baseload FTRs by March 2010.

176. If the Commission does not rule now that the restoration will continue beyond 5 years, the Midwest TDUs ask that the Commission at least reserve judgment on termination of the restoration provisions until everyone has gained some experience on the effects of the restoration process.

iii. Discussion

177. The Commission is concerned that parties with long-term resources remain able to receive sufficient FTRs over the life of the contract or resources. The question is how to do it. We believe that FTR restoration is justified as a 5-year transition mechanism, but is too cumbersome to be put in place for decades. As we noted in section D, *supra*, in the broader context of the general methodology for providing FTR coverage, we required the Midwest ISO to provide sufficient information on the restoration process so that the parties will be able to prepare for termination of the restoration. This requirement will permit parties to assess their likely access to FTRs after the transition period. Moreover, as the market begins operations, Midwest ISO market participants will begin discussing alternative methods, such as FTR auctions with revenue rights, and parties will also have a clearer view of where their interests lie under such alternatives. In addition, market pricing will clarify where needed investments should be made in transmission and generation. The Commission has worked in many regions to promote such investments and we will continue to work with the Midwest ISO and stakeholders to develop regional investments.

g. Alternative Restoration Methods

i. Background

178. In the TEMT II Order, the Commission supported a proposal to allocate counterflow flowgate rights (FGRs) to transmission customers whose FTRs in the initial allocation were not fully restored.[147]

ii. Requests for Rehearing

179. The Midwest TDUs ask for Commission clarification that the costs of "restoration-enabling" flowgate rights will be broadly uplifted no later than the summer of 2005. The Midwest TDUs state that the provision included in the TEMT II order regarding a remedy involving FGRs could meet their objectives, if the Commission can clarify how FGRs will actually work.

180. As the Midwest TDUs understand FGRs they will have these aspects: (1) a customer with a prorated FTR will have the option to obtain an FGR in the counter-flow direction on the facility that was the constraint that prevented the award of FTRs; (2) each megawatt of FGR will be modeled as if one megawatt of point-to-point service was counter-flowing over the limited facility; (3) the customer that accepts the FGR places two bets that congestion won't reverse, because first it gets an FTR obligation and second for any hours when congestion reverses and activates the FGR, the customer must pay the generation savings that would accrue if the FGR's counterflow transfer capacity were expanded by the FGR quantity; and (4) restoration FGRs will be available without charge to customers whose baseload FTRs were prorated. The Midwest TDUs would like the Commission to confirm or deny their assumptions about the mechanics of FGRs. Additionally, the Midwest TDUs request that the Commission direct the Midwest ISO to provide for full initial FTR restoration, through FGRs or another effective mechanism, by no later than June 1, 2005 because of concerns about restoration during the summer peak season.

iii. Discussion

181. We agree with Midwest TDUs that the use of counterflow FGRs could be an avenue for additional awards of FTRs to parties that have been pro-rationed through the initial allocation. However, we also agree with Midwest TDUs that the properties of such rights will largely determine the resulting benefits to the holder. In the TEMT II Order,

[147] TEMT II Order at P 191.

we supported OMS's request that the Midwest ISO "should consider whether or not restoring the full point-to-point FTRs and issuing counter-flow FGRs to the transmission customer will reduce the harm to the transmission customer."[148] Based on the Midwest TDUs' questioning, and on reconsidering our interpretation of the OMS's recommendation, we are not sure that our characterization of such rights in the TEMT II Order was correct. Certainly, as Midwest TDUs state, under some interpretations, a one-to-one assignment of a counterflow FGR for an additional FTR (1 FTR = 1 MW injected at the source point and 1 MW withdrawn at the sink point) could result in a net zero improvement. Given the possibility of alternative FGR specifications, and given the stated objective of the OMS and the Commission to "reduce the harm" (if any) through the assignment of such rights, we will wait until the Midwest ISO complies with our request to determine whether the application of such rights has been done appropriately.

h. Allocation Schedule and Time Period for Allocated FTRs

i. Background

182. The TEMT II Order required the Midwest ISO to align the calendar of its annual FTR allocation with that of PJM. The Commission imposed this requirement on the recommendation of parties and with the support of the Midwest ISO as a means to reduce the seam between the two markets. In addition, the TEMT II Order required the Midwest ISO to offer monthly FTRs as soon as possible.[149]

ii. Requests for Rehearing

183. Manitoba Hydro argues that the TEMT II Order's requirement that the annual FTR allocation is undertaken on the same schedule as PJM is not consistent with Manitoba Hydro's seasonal contracts for sales of capacity and energy into MAPP.

184. Manitoba Hydro requests that the Commission direct the Midwest ISO to offer monthly nominations in the initial and subsequent allocations or provide some adjustments to the FTR allocations to provide for equitable treatment for FTRs that support seasonal transactions that are not defined identically to the Midwest ISO definition.

[148] OMS Comments at 19 (May 7, 2004). *See also* TEMT II Order at P 190-92 (accepting OMS's recommendation).

[149] TEMT II Order at P 190.

185. Ameren argues that the Commission's requirement that Midwest ISO offer monthly on-peak and off-peak FTRs in Tiers 2 to 4 in the initial allocation period and if not, in the subsequent one, could leave too little time for participants to gain experience with the allocation. Ameren requests rehearing and asks that the Commission require that this change to the allocation be considered after both the initial six month and subsequent nine month allocations have been completed.[150]

iii. Discussion

186. Manitoba Hydro, in its protest and rehearing request, has not provided us with descriptions of its contracts with Midwest ISO members. On the assumption that certain of its contracts will be eligible for FTRs, we address Manitoba Hydro's issue. We understand Manitoba Hydro's concern about long-term existing contracts whose terms of duration and changes in direction of flow cannot be easily accommodated in the conversion to seasonal FTRs. We agree that the customer that has a contract for flow in the opposite direction to the seasonal FTR for, *e.g.*, a month of the season, should be covered as if they had the appropriate FTR for that month. The simplest way to provide such coverage is to provide monthly FTRs. However, the Midwest ISO states in its October 5, 2004 Compliance Filing that the earliest time it can offer monthly FTRs is during the second annual allocation.[151] Therefore, we will require the Midwest ISO to work with parties with such contracts to provide appropriate market designs to minimize such problems by the next allocation, if it cannot implement monthly nominations by that date. Accordingly, the Midwest ISO is directed to make a filing with the Commission by July 1, 2005 to implement an equitable solution if monthly nominations are not in place in time for the second annual nomination.

187. We will dismiss Ameren's request for rehearing to delay implementation of monthly FTRs. As demonstrated in the Manitoba Hydro request for rehearing, the addition of monthly FTRs will significantly improve the FTR coverage of some market participants. And while it is important not to rush design improvements into the market before participants are ready for them, it is also important to introduce design elements that improve the efficiency of the market as soon as possible. Further, it is not clear what additional experience would be gained by participants under the proposed delay.

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[150] Ameren Request for Rehearing at 12-13.

[151] Midwest ISO Transmittal Letter at 14, Docket Nos. ER04-691-007 and EL04-104-006 (Oct. 5, 2004).

3. Illustrative FTR Allocation

a. Background

188. In response to Commission requirements, the Midwest ISO conducted one "illustrative" FTR allocation, with final results filed with the Commission on April 28, 2004.[152] As discussed in the Procedural Order and the TEMT II Order, despite clear problems with the process of the illustrative allocation and the results, the Commission determined that continued progress on FTR allocation for the Midwest ISO markets was better served not by repeating the illustrative allocation but by focusing efforts on establishing a better procedure for market participant input and review of the FTR modeling, finalizing the allocation rules, and proceeding to an actual initial allocation.[153] The Commission also required the Midwest ISO to repeat the initial allocation process at the six-month mark rather than after a full year, in part to allow for market participant learning.

b. Requests for Rehearing

189. Midwest Parties state that the Commission unreasonably and arbitrarily abandoned additional illustrative FTR allocations. Midwest Parties argue that the ability to achieve an accurate illustrative allocation is a test of Midwest ISO's market readiness and should be undertaken regardless of any delay in the start of the Day 2 market. Midwest Parties state that the decision not to conduct a further illustrative FTR allocation creates uncertainty and skepticism.

c. Discussion

190. We do not agree with Midwest Parties that our decision not to require an additional illustrative FTR allocation was unreasonable and arbitrary. The TEMT II Order was clear in stating that, based on the experiences with the illustrative allocation, we would require that the process for conducting the initial allocation "addresses stakeholder concerns about the FTR modeling and allows sufficient time to correct errors and include adjustments to the allocation…"[154] Moreover, the TEMT II Order addressed

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[152] Midwest Independent Transmission System Operator, Inc., Informational Filing of Illustrative Financial Transmission Rights, Docket No. ER04-691-000 (April 28, 2004).

[153] Procedural Order at P 95; TEMT II Order at P 201-202.

[154] TEMT II Order at P 202.

market readiness, and required the Midwest ISO to adopt commercial readiness metrics suggested by the OMS and stakeholders and to certify to the Commission, 30 days before market start-up, the reliability and readiness of its systems.[155] We would expect that FTR modeling assumptions are part of commercial readiness and that the Midwest ISO would not certify readiness in the event of continued problems in the initial allocation. In addition, the TEMT II Order, this order on rehearing, and the subsequent filing by the Midwest ISO of its compliance, will clarify the rules for the allocation; the illustrative allocation did not have the benefit of final market rules. Finally, although we did not state this reason in the TEMT II Order, while "illustrative" non-binding nominations do familiarize participants with a market procedure, they do have the problem, well understood by the Commission and all market participants, that they may not elicit the same nominations by participants as an actual nomination process. Hence, no illustrative allocation can be expected to exactly correspond to the actual initial allocation. These elements together make our decision not to require an additional illustrative FTR allocation reasonable and not arbitrary. We expect that Midwest ISO staff will help assure stakeholders' understanding of the results of the actual initial allocation by providing sufficient accessible information and a forum to address stakeholder questions and concerns regarding the actual initial allocation before the start of the market.

4. FTR Rules for Generation Additions and Retirements and Network Upgrades and Expansion

a. Background

191. In the TEMT II Order, we required the Midwest ISO to begin discussions with stakeholders on the need for, and feasibility of, long-term FTRs within 180 days of the start of the Day 2 markets. We did so because we agreed with intervenors that long-term FTRs could be attractive as support for investments in long-term transmission assets. In the TEMT II Order, we did not address a protest by WPPI that requested that, upon the bringing into service of additional transmission capacity, the Midwest ISO be required to grant FTRs first to parties who participate in the transmission investment and whose FTRs were pro-rationed in the annual allocation.

b. Requests for Rehearing

192. The Midwest TDUs argue that the existing TEMT II order fails to put any obligation on the Midwest ISO to ensure that the grid is developed to support the continued simultaneous feasibility of existing FTRs before customers lose restoration

[155] *Id.* at P 55.

protection. To counter the potential for inadequate grid development, the Midwest TDUs ask the Commission to direct the Midwest ISO to include in its transmission expansion plan whatever upgrades are necessary to ensure simultaneous feasibility of all network resources that are reasonably expected to be used at peak load conditions. They also ask for a presumption that all project costs needed to fulfill the Midwest ISO's network service planning obligation will be rolled in, and it should hold the Midwest ISO accountable that such projects are completed competently and on time. Finally, until these grid projects are completed they request that the restoration procedures remain available.

193. Midwest TDUs request that on rehearing, the Commission clarify that it intended the Midwest ISO to make filings on long-term FTRs within 180 days of the start of the Day 2 market, rather than simply commence discussions with stakeholders. In addition, the Midwest TDUs ask that the Commission direct Midwest ISO to tie the development and availability of long-term FTRs to the network resource and planning process.[156] Midwest TDUs argue that the failure to develop a policy on long-term FTRs and to integrate it with the resource planning process leads to a bias in investment towards more expensive gas resources and against cheaper coal units.

194. WPPI argues that the Commission erred by not requiring that prorated FTRs are restored as additional transmission facilities are constructed.[157]

c. Discussion

195. We will not at this time act on Midwest TDUs' request for transmission expansion planning to support allocation of pro-rationed FTRs before the end of the FTR restoration period. There is no evidence yet that the existing allocation methodology is not able to provide sufficient FTRs even without restoration; we have required the Midwest ISO to provide information to evaluate that prospect in this order. Once this record is available, the Midwest ISO should consider it in its transmission expansion planning, consistent with the requirement that it provide service that is efficient, reliable and non-discriminatory.

196. We agree with Midwest TDUs that the TEMT II Order is not consistent between P 209, where Midwest ISO is instructed to begin discussions on long-term FTRs for transmission expansion within 180 days of the start of the Day 2 markets, and P 650,

[156] Midwest TDUs Request for Rehearing at 39-45.

[157] WPPI at 4.

where the Midwest ISO is instructed to make a filing on the subject by the same date. We do not believe that the Midwest ISO could formulate viable rules for awards of long-term FTRs in that period, given the effort that will be dedicated to a successful market start and also because the topic has proven complicated in other markets. Our intention in the TEMT II Order was to initiate discussions on the topic in the first six months, but not aim at a full filing at that point. We will not change that position here, but we will require the Midwest ISO to submit an informational filing within 180 days of the start of the market explaining any progress with stakeholders to that date and providing a date for a future filing.

197. We also agree with WPPI that parties that undertake transmission expansions, whether individually or jointly, should receive the FTRs that result from incremental transmission transfer capability. What is not immediately clear is whether those FTRs are assigned first to parties with pro-rationed FTRs in the allocation that could be restored through the expansion or, by some formula, are otherwise awarded. For example, the parties funding the expansion may not proportionally have pro-rationed FTRs that could be subsequently restored. Hence, we will require the Midwest ISO and stakeholders to discuss the appropriate rules in this circumstance and file the results with the Commission within 180 days of the start of the market.

d. FTR Auction Settlement revenues

i. Background

198. Section 45.6 of the TEMT provides that the Midwest ISO will charge the winning FTR bidders the market clearing price and credit the sellers the market clearing price. In the event that there is any remaining revenue from the FTR auction, the Midwest ISO will allocate the revenue among those charged for firm network and point-to-point transmission service through a credit back to those transmission customers.

ii. Requests for Rehearing

199. Cinergy complains that the tariff should contain the necessary detail regarding how charges will be calculated, allocated and assessed. Cinergy request that these charges be included as a tariff rate schedule.

iii. Discussion

200. We interpret Cinergy’s concern to be a lack of detail regarding the calculation of the revenue credit to transmission customers, rather than the market clearing price charge. On this basis, we agree with Cinergy that section 45.6 of the TEMT does not explain how Midwest ISO will calculate the credit of remaining revenues. Moreover, the provision

does not explain which transactions constitute firm transmission service and whether that includes Option B GFAs and carved-out GFAs. While we agree that further information is required in the TEMT, Cinergy has not demonstrated the reason that the information must be in a separate rate schedule. We direct Midwest ISO to clarify section 45.6 of the TEMT in its next compliance filing to provide details on how the credit will be calculated and assessed.

5. Locational Marginal Pricing

a. Requirement for LMP Market

i. Background

201. In the TEMT II Order, the Commission approved the Midwest ISO's proposal to use LMP to settle energy sales and purchases in the day-ahead market and the real-time market, to calculate transmission usage charges in both of the markets, and to settle FTRs in the day-ahead market. However, the Commission did approve certain transitional measures for certain entities in moving to the LMP system.

ii. Request for Rehearing

202. LG&E argues that the Commission has not adequately explained its departure from Order No. 2000.[158] In that proceeding, the Commission found that LMP and centralized markets were not requirements for RTO participation, and LG&E says that its commitment to join an RTO relied in part on the Commission's assurances that Day 2 markets were not a required aspect of RTO membership.[159] LG&E adds that the courts have cited with approval the Commission's approach to RTO membership, which turns on voluntary coordination.[160] LG&E avers that the Commission erred when it found in

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[158] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (2000), *order on reh'g* Order No. 2000-A, 65 Fed. Reg. 12,088 (Feb. 25, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[159] LG&E Request for Rehearing at 30 (citing *E.ON AG*, 97 FERC ¶ 61,049 at 61,283 (2001)).

[160] *Id.* (citing *Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001); *Atlantic City Electric Company, et al. v. FERC*, 295 F.3d 1, 12 (D.C. Cir. 2002)).

the TEMT II Order that rulemaking proceedings were not needed to consider the Midwest ISO's congestion management proposal. It argues that many aspects of the Day 2 markets were not addressed in Order No. 2000, or were specifically rejected as requirements for RTOs. LG&E argues in particular that Order No. 2000 did not require RTOs to adopt a centralized security-constrained dispatch model, day-ahead or real-time energy markets, LMP or FTRs. LG&E asks why, if the effects of Order No. 2000 required a rulemaking, major departures from the rule should be subject to adjudication without an adequate hearing.

203. LG&E reiterates its prior argument that the TEMT exceeds the requirements set out in the Commission's Wholesale Power Market Platform. It states that the Commission, in weighing the appropriateness of LMP and alternatives, stated that LMP can be costly and difficult to implement, especially by entities that have not operated as tight power pools.[161] LG&E believes that the Midwest represents the kind of "costly and difficult" scenario that the Commission recognized in Order No. 2000. It alleges that the Commission is attempting to use the Midwest ISO's proposal as a vehicle for implementing the most controversial aspects of Standard Market Design, but without the voluntary market participation feature of the Standard Market Design Notice of Proposed Rulemaking. LG&E argues that it would be inappropriate to allow the Midwest ISO to implement Standard Market Design through an RTO with no previous experience operating as a tight power pool. It states that this action demonstrates that the Commission has disregarded its statements in Order No. 2000 regarding the appropriateness of LMP. LG&E concludes that this action constitutes arbitrary, capricious and unreasoned decision-making.

iii. Discussion

204. We deny LG&E's request for rehearing. Our actions here are consistent with Order No. 2000 and the Commission's intent that market participation in Standard Market Design (SMD) be voluntary. First, as noted above, the TEMT does not require anyone to buy and sell through the central market.[162] Moreover, as we have noted in

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[161] *Id.* at 21 (citing *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Design*, Notice of Proposed Rulemaking, 67 Fed. Reg. 55,452 (Aug. 29, 2002), FERC Stats. & Regs. ¶ 32.563 at 31,127 (2002) (SMD NOPR)).

[162] We do note, however, that in both cases, transmission customers are required to settle imbalances at real-time prices generated by the energy market, rather than paying the current tariff's imbalance charges.

previous orders, Order No. 2000 requires that RTOs develop a congestion management plan.[163] The TEMT II Order approved the LMP congestion management proposal filed by the Midwest ISO under section 205 of the FPA, finding that the proposal was just and reasonable. LG&E, as a customer under the Midwest ISO OATT, is subject to any and all revisions to the OATT, whether routine or extensive, that the Midwest ISO seeks under section 205 of the FPA and that the Commission finds are just and reasonable. Because the Commission has found that the TEMT – a replacement of the OATT – is just and reasonable, LG&E, like all customers under the Midwest ISO tariff, is bound by its terms.

205. LG&E has known since early 2003 that the stakeholders of the Midwest ISO had indicated a preference for LMP congestion management and that the Midwest ISO was developing a Day-2 market on that basis.[164] To halt progress on that market development while the Commission undertakes a rulemaking, as LG&E proposes, denies the preferences of most of the Midwest ISO members to start the markets expeditiously and denies them the benefits they perceive in implementing LMP markets. And this denial would be for the purposes of evaluating alternatives to centralized security-constrained dispatch, day-ahead or real-time energy markets, LMP or FTRs, according to LG&E. However, LG&E has not convinced the Midwest ISO stakeholders nor has it provided evidence to indicate that the alternatives would be superior or otherwise offer advantages compared to the Midwest ISO plan.[165] Lacking evidence that the market plan supported by stakeholders is unjust and unreasonable, the Commission has no basis for rejection of

[163] *See Midwest Independent Transmission System Operator, Inc.*, 97 FERC ¶ 61,326 at 62,511 (2001) *reh'g denied* 103 FERC ¶ 61,169 (2003). We disagree with LG&E's statement that Order No. 2000 rejected LMP pricing as a requirement for RTOs. *See* LG&E at 6. The relevant language of Order No. 2000 indicates the Commission encouraged flexibility: "Therefore we will allow RTOs considerable flexibility to propose a congestion pricing method that is best suited to each RTO's individual circumstances." Order No. 2000 at 31,127.

[164] *See* Declaratory Order at P 30 ("The Midwest ISO has also worked with stakeholders to develop its Day-2 congestion management approach and has indicated a disposition of this group toward LMP.").

[165] While LG&E cites to the possibility of higher costs due to the fact that the Midwest ISO is not a tight power pool, these concerns are speculative and can not be used as a basis for reasoned decision-making.

the TEMT. Weighing the negative impacts of delay against the uncertain, at this time unknown, benefits of a rulemaking proceeding, we conclude that such a proceeding would not be in the public interest. For these reasons, we deny rehearing.

206. We reaffirm our finding in the TEMT II Order that a rulemaking proceeding is not necessary to consider the Midwest ISO's energy markets proposal. As explained above, our approval of the TEMT is not a departure from Order No. 2000, as LG&E alleges, but a region-specific proposal that adopts some of the options presented in Order No. 2000. As such, no modification of the Commission's RTO rules and regulations through an administrative rulemaking is needed for the Commission to accept the Midwest ISO's proposal.[166]

b. Zonal Pricing

i. Background

207. In response to a request to permit zonal pricing, the Commission explained that it had approved zonal pricing for load that includes multiple load-serving entities within the zone, but that such zonal pricing was the result of stakeholder processes, not Commission direction. The Commission encouraged stakeholders to consider such aggregations in future discussions, including those involving the formation of independent transmission companies (ITCs), but did not require that zonal pricing be used.

ii. Requests for Rehearing

208. Midwest MTG states that averaging is necessary to avoid potentially devastating impacts on smaller systems that may have only one or two nodes. Smaller systems, such as Midwest MTG members, may be subject to market power abuse resulting in very high prices for power deliveries to their nodes.[167] Aggregations of nodes into a zone may help thwart such market power abuse. Moreover, smaller systems such as the Midwest MTG

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[166] The Commission, like other federal agencies, is required to publish "substantive rules of *general* applicability" in the Federal Register. 5 U.S.C. § 552(a)(1)(D) (2000) (emphasis added). Changes to those generally-applicable rules are made through administrative rulemaking proceedings. *See* 5 U.S.C. § 553 (2000).

[167] Midwest MTG states that the Midwest ISO's bid cap of $1,000/MWh is not based on costs and if prices approach the bid cap level, the Commission must assume that those prices reflect market power. Midwest MTG Supplemental Request for Rehearing at 11.

members will have no means of curing adverse LMP because they do not control transmission construction and are too small to build localized generation. Midwest MTG states that it does not cause transmission inadequacies that give rise to congestion costs.

209. Midwest MTG asserts that state regulators are likely to require the large utilities to average nodal prices for their retail customers. The Midwest MTG also argues that by giving the transmission owner veto power over whether there will be zonal pricing, it could lead to small systems being forced to sell their assets to larger transmission owners. Transmission owners could argue that small systems with high LMPs could have their LMPs averaged in a zonal rate if they agreed to sell to the transmission owner. Midwest MTG states that giving the transmission owner veto power is anti-competitive.

210. The Midwest MTG believes the option to merge LMPs into a zonal rate should not be the transmission owners but the smaller system's option to prevent the mutual consent requirement from being used as a competitive weapon against a transmission dependent utility. The Midwest MTG asserts that since the smaller system LMP will have little impact on zonal LMP of the much larger transmission owner, this asymmetry should impose no great burden on the larger transmission owner.

211. Midwest MTG states that when larger systems did not want to share reserves on an equal basis with smaller competitors, the Commission and the courts required them to do so.[168] Likewise, Midwest MTG believes that larger systems should not be able to refuse or place burdens on smaller systems by vetoing zonal pricing. While the Commission may generally want to promote resolution of TEMT issues by stakeholder consensus, Midwest MTG states that where discrimination against smaller systems will otherwise result, the Commission has a statutory duty under the FPA to step in and prevent abuse.[169]

iii. Discussion

212. We deny MTG's request for rehearing. LMP provides price signals to market participants showing where additions to the transmission system or generation need to be made. While MTG claims that it is not big enough to cure adverse LMPs, MTG may hedge potential congestion costs through the allocation or purchase of FTRs. Further, we disagree with MTG that high LMPs represent, *de facto*, market power since congestion

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[168] Midwest MTG Supplemental Request for Rehearing at 10 (citing *Gainesville Utils. Dep't v. Florida Power Corp.*, 402 U.S. 515 (1971) (*Gainesville*)).

[169] *Id.* at 11 (citing *Gulf States Utils. v. FPC*, 411 U.S. 747 (1973)).

has many causes. Nonetheless, if MTG believes that market abuse is occurring, MTG is encouraged to report its concerns to the IMM or the Commission. Additionally, we find MTG's concerns on utilities using nodal pricing to buy out smaller systems in an anti-competitive manner constitute mere speculation at this time.

213. We disagree with MTG's interpretation of *Gainesville* which MTG contends required large utilities to share reserves. *Gainesville* actually involved a request for interconnection that would result in a lower reserve requirement for Gainesville. The Commission required Gainesville to pay the entire cost of the interconnection but Florida Power contended that Gainesville should pay an additional annual sum for reserve service. The Commission disagreed stating that the cost of providing service and facilities were already equitably determined after a careful analysis. Therefore, the dispute in *Gainesville* was the cost to provide the service and facilities, not whether the interconnection should have been made, and not whether reserves should be shared. Moreover, just as Gainesville sought interconnection to lower its cost of reserves, MTG may seek additional transmission or generation investment to lower its LMP.

214. Accordingly, we will not require the formation of zones at the option of the transmission dependent utility and instead continue to rely on stakeholder processes to determine pricing zones.

F. Market Monitoring and Market Power Mitigation

1. BCAs

a. BCA Thresholds

i. Background

215. In its TEMT II Order, the Commission approved the Midwest ISO's proposal for conduct thresholds of the lower of a 300 percent or $100/MWh increase, and impact thresholds of a 200 percent or $100/MWh increase to be applied in BCAs.[170] The Commission found that the thresholds are very similar to those adopted in NYISO and ISO-NE, especially in areas with low to moderate market power concerns, such as BCAs.

[170] A Broad Constrained Area (BCA) is an electrical area in which sufficient competition usually exists, even when one or more transmission constraints are binding, or into which the transmission constraints bind infrequently, but within which a transmission constraint can result in substantial locational market power under certain market or operating conditions.

We pointed to the resource margin of 20 percent in the Midwest ISO footprint, and the lack of a capacity market as reasons that the thresholds should not be lowered to the lower of 50 percent or $25/MWh.[171]

ii. Requests for Rehearing

216. In their rehearing request, Midwest TDUs reiterate their Protest argument that economic withholding thresholds to be applied in BCAs should be no larger than the lower of 50 percent or $25/MWh. Their rehearing request states that the proposed approved thresholds are "not factually justified, invite gaming, and mask market power exercise as 'scarcity pricing'."[172] Midwest TDUs state that the testimony of Dr. Kirsch refuted the claims of the IMM that there could be legitimate reasons for an owner to raise the bid of its unit over the threshold levels, most of which involve factors that cause the marginal cost of the unit to rise. Dr. Kirsch's testimony stated that in twenty years of working with generator marginal cost data, he has never seen errors in the marginal cost estimates or short-term forecast errors that have been anywhere near the 300 percent or $100/MWh thresholds proposed by the Midwest ISO. Dr. Kirsch explains that such forecast errors might be associated with natural gas price spikes, but the reference levels are adjusted for such changes. Midwest TDUs also claim that permissive thresholds combined with low risk of being caught will encourage bidders to engage in gaming to slowly but steadily raise their reference levels. The Commission largely ignored this evidence as well as what the Midwest TDUs say is the IMM's failure to define any circumstances under which marginal costs might unexpectedly jump by 300 percent or $100/MWh.

217. Midwest TDUs also contest the Commission's statement that these thresholds are similar to those applied in comparable areas within NYISO and ISO-NE. Midwest TDUs say that the areas in question in ISO-NE and NYISO are unconstrained areas, while BCAs that have binding constraints give rise to market power concerns. They contend that the Commission should require the Midwest ISO to adopt a threshold to be applied in BCAs of the lower of 50 percent or $25/MWh, as is applied in comparable areas of ISO-NE.

218. Midwest TDUs also argue that the Commission's reference to "significant differences" between the Midwest ISO's and ISO-NE's markets neither justifies the thresholds nor supports the suggestion that high BCA thresholds are needed to support

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[171] TEMT II Order at P 315.

[172] Midwest TDUs Request for Rehearing at 73.

investment. The 20 percent resource margin in the Midwest ISO, to which the Commission cites, rebuts the concerns about the lack of a resource adequacy market, according to the Midwest TDUs. They say that resource adequacy in the Midwest is attributable to the continued prevalence of traditional investment signals, state and Regional Reliability Organization resource adequacy requirements combined with other fixed-cost recovery mechanisms, including long-term contracting, and retail rate base cost recovery. Midwest TDUs state that given these opportunities for fixed-cost recovery, the absence of an organized reserves market does not support the BCA threshold levels.

iii. Discussion

219. In evaluating the Midwest ISO's proposal for monitoring and mitigation, the Commission's obligation is to assure that rates are just and reasonable for buyers and sellers. The IMM must monitor the market and assist the Commission in enhancing the competitive structure of the market and assuring that prices are properly reflective of supply and demand conditions. While we can learn from the experiences in other markets, the monitoring and mitigation proposals of the various RTOs and ISOs need not be identical in order to be judged just and reasonable. Here, the Midwest ISO proposed conduct and impact thresholds that we find are just and reasonable and accept. They are similar to thresholds applied in other markets and for which Market Monitoring Unit reports have shown generally competitive outcomes with limited need for mitigation. The IMM will be watching these markets carefully in addition to monitoring for any rule changes needed to ensure competitive markets (bearing in mind that the markets have not yet started up). Should the IMM find problems as markets become operational, it should inform both the Midwest ISO and the Commission, and propose modifications that it believes will address these concerns.

220. Midwest TDUs have pointed to various differences between the Midwest ISO's proposed design for mitigation measures and the designs in NYISO and ISO-NE that they believe should translate into narrower thresholds for BCAs in the Midwest ISO. We acknowledge that there are differences, but we do not agree that these differences require changes in the threshold levels to be applied in the Midwest ISO. In a section 205 filing, the proposal must be just and reasonable, but it need not be identical to that proposed in other markets. We find that the BCA mitigation thresholds to be applied in the Midwest ISO meet this standard.

221. The potential for over-mitigation would increase as BCA thresholds are tightened. Over-mitigation could adversely affect a generator's ability to receive appropriate revenue. Even though generators are achieving some fixed cost recovery through state and RRO resource adequacy programs and long-term contracts, the lack of an RTO capacity market means that one important source of revenue is not yet available to

generators. BCAs are areas in which market power concerns are not expected to be significant on an on-going basis, and are in a region with high capacity reserve margins. Thus we expect market power problems to be infrequent in these areas. We find that the proposed thresholds for BCAs are appropriate due to lack of an RTO-wide capacity market and because they protect against the exercise of market power while letting generators offer their resources competitively under a range of market conditions without concerns about their bids being mitigated.

b. Mitigation Beyond BCAs

i. Background

222. In its TEMT II Order, the Commission rejected arguments that built-in mitigation should apply to electrical areas not qualifying as BCAs and NCAs.[173] However, the $1,000 offer cap would apply to all areas in the Midwest ISO. We found that generators in such areas, those expected to be competitive under extreme system conditions, should not be screened for mitigation as a matter of course. We stated that if the IMM observes market power problems not captured within the BCA and NCA screening mechanism, the IMM should notify the Commission.

ii. Request for Rehearing.

223. In their request for rehearing, the Midwest TDUs want Module D to apply the lesser of 300 percent or $100/MWh market impact thresholds to areas classified as neither NCAs nor BCAs. They say the Commission’s conclusion cites no evidence, ignores evidence of the need for mitigation in the rest of Midwest ISO, and contradicts prior Commission findings.

iii. Discussion

224. We stand by our previous finding on this issue. As we stated in the TEMT II Order, it should be unnecessary to have generators screened for mitigation in non-BCA and non-NCA areas, *i.e.*, areas where markets are likely to be competitive even under extreme conditions.[174] If the IMM observes market power problems that are not captured

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[173] NCAs are electrical areas defined by one or more transmission constraints that are expected to be binding for at least 500 hours during a given 12-month period, within which one or more suppliers is pivotal.

[174] TEMT II Order at P 273.

in the BCA or NCA screening process, the IMM should notify the Commission. Indeed, the definition of NCAs and BCAs and their associated mitigation already provide the potential for all areas of the Midwest ISO footprint to be mitigated if need be. In particular, NCAs are defined to be areas with substantial potential for the exercise of market power. BCA areas are defined to be those electrical areas in which sufficient competition usually exists even when one or more transmission constraints are binding, or into which the transmission constraints bind infrequently, but within which a transmission constraint can result in substantial locational market power under certain market or operating conditions. Because BCAs are not defined in advance, but as market constraints develop and as generators affecting the constraints are identified by their Generation Shift Factor (GSF) levels,[175] areas are included in the screening for and application of mitigation as market conditions arise that allow for the exercise of market power.

225. The Commission will, of course, re-examine this finding should we determine that BCA-specific mitigation should be removed, and should additional mitigation be needed outside of NCA areas.

c. Sunset on BCA-Specific Mitigation

226. BCAs are not identified in advance by the IMM (although prior BCAs are to be identified on the website), but generators within them will be monitored and mitigated when appropriate, using thresholds that are less severe than those associated with NCAs. Mitigation will occur to generators found to lie within the BCA (using GSF cutoffs) when there is a constraint and when the generator fails both its conduct and impact tests, using thresholds associated with BCAs.[176] The IMM will use GSFs in the determination of which generators lie within a BCA, and the GSFs are posted.

227. In the TEMT II Order, the Commission expressed concerns about the use of GSFs in the determination of generators that lie within BCAs, and said that it would pay close attention to these issues. The Commission approved the use of BCAs as a screen for the use of mitigation in the Midwest ISO for a one-year period. During that period, the Order provided that the IMM will be required to submit quarterly reports with the Commission

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[175] A generation resource's GSF is the incremental increase or decrease in flow on the flowgate associated with an incremental increase or decrease in the generation resource's output.

[176] The thresholds vary by bidder, but are associated with a strict formula based upon the unit's reference price.

to allow us to assess the use of BCAs and mitigation within them. The Commission stated that should it find problems with the IMM's discretion in the application of mitigation within BCAs, it will take appropriate action, including terminating the provisions for mitigation within BCAs before the end of the one-year period. The Midwest ISO may file to extend the use of BCA-specific mitigation beyond the one-year period, based on its analysis.

i. Requests for Rehearing

228. Coalition MTC and Midwest TDUs request rehearing on the sunsetting of generator mitigation within BCAs. Midwest TDUs say that, given the Commission's response to the concerns it raised about the under- and over-inclusiveness of GSFs used in specifying generators within BCAs, it expected the Commission to take steps to address the problem. Midwest TDUs state that they did not expect the Commission to meet these concerns by requiring the IMM to file in order to be allowed to extend mitigation within BCAs beyond one year, and to threaten to "pull the plug" on such mitigation earlier. Midwest TDUs assert that it is unconscionable that the Commission would ignore the market power risks associated with constrained areas in Midwest ISO. According to the Midwest TDUs, neither ISO-NE's nor NYISO's mitigation measures include similar probationary provisions.

229. Coalition MTC contends that the Commission's action "leaves consumers exposed and unprotected against the exercise of market power."[177] It claims that while the Commission has identified concern over the appropriateness of some aspects of BCA mitigation measures, it does not follow that the appropriate fix is "the equivalent of granting generators in BCA regions a license to steal."[178] They point out that the proposed BCA mitigation is applied only after both a conduct and an impact test are failed by a generator. Coalition MTC asserts that by mandating the application of BCA measures to sunset after one year, the Commission has abandoned its duty to assure just and reasonable rates. They also say the Commission's actions suggest that an offer deemed an unacceptable exercise of market power 365 days after market start-up, will become an acceptable offer in the Commission's eyes on the 366th day.

[177] Coalition MTC Request for Rehearing at 7.

[178] *Id.* at 7.

ii. Discussion

230. We do not take lightly the concerns about the potential for the exercise of market power in BCA areas. However, we are also concerned that any mitigation be applied in an appropriate manner. In evaluating the Midwest ISO's proposal for monitoring and mitigation, the Commission's obligation is to assure that monitoring and mitigation occur such that rates are just and reasonable for buyers and sellers. In mitigating bids, the difficulty is to find the appropriate balance between under-mitigation and over-mitigation, because each has its costs. While under-mitigation may result in some exercise of market power that is not mitigated, over-mitigation means more frequent intervention in the market, and that some competitive market results will be mitigated. This could lead to decreased confidence in the market, and thus less investment in needed infrastructure.

231. We are concerned that the application of mitigation, beyond the $1,000 bid cap, in BCA areas could result in excessive mitigation. This is especially true where the IMM may have some discretion in applying that mitigation. For these reasons, we believe that the need for mitigation within BCAs should be re-evaluated after there is some operational market experience. We believe that the quarterly reports on mitigation within BCAs will allow the IMM to determine the need for continuing mitigation there and allow the Commission to assess the need and appropriate mitigation within BCAs prior to the expiration of the one-year period. If the Midwest ISO or the IMM sees a need for continuing mitigation, the Midwest ISO can file to continue such mitigation with the Commission. The Commission will then judge if the benefits of such mitigation exceed its costs, in terms of over-mitigating versus under-mitigating the market.

2. NCA Definition

a. Background

232. NCAs are defined as electrical areas with one or more transmission constraints that are expected to be binding for at least 500 hours during a given 12-month period and within which one or more suppliers are pivotal. A supplier is pivotal when the output of some of its generation resources must be increased or decreased to resolve the transmission constraint during some or all hours when the constraint is binding. When a supplier is pivotal, a binding transmission constraint cannot be relieved without changing the base loadings for other suppliers' generation resources. Pivotal suppliers will be determined using transmission load flow cases reflecting a variety of market conditions. Very tight conduct and impact thresholds are applied within NCAs because of a high potential for the exercise of market power there.

233. Midwest TDUs argued in their initial comments that NCAs should be redefined in terms of the minimum number of hours of congestion needed to qualify for the NCA distinction. They cited to the possibility of all 375 summer peak hours being congested, yet not meeting the 500-hour minimum for the NCA definition. They also argued that an HHI screen of 1800 should be used to determine additional areas that should be designated as NCAs.

234. The TEMT II Order concluded that the definition of an NCA should not be changed by reducing the number of hours necessary for an NCA classification below 500. We found that a 500-hour minimum is used by ISO-NE, and that it appears to properly balance mitigation versus over-mitigation. We noted that we had several problems with the Midwest TDUs' point that peak summer hours total 375, and that the minimum number of hours in the NCA definition should be lowered. First, constraints are not so much related to peak system conditions, but to unexpected generator outages. Second, during peak system conditions, generators are likely to be running throughout the Midwest ISO footprint, and areas with sufficient generation but concentrated ownership are not likely to see constraints coming into their area. Under these conditions, we noted that prices may be high, but that is likely to be from system scarcity. In addition, we noted that it is not clear that peak conditions are the optimal time for a generator to exercise market power, because they risk bidding so high as to not be selected, and thus would forgo the high scarcity prices in the market. We also found that if the IMM determines that if the expected constraints or hours of constraint prove false, the IMM can ask the Commission to redefine the NCA status, or lack thereof, of a flowgate.

235. The Commission also rejected the Midwest TDUs argument that load pockets where the generation ownership HHI exceeds 1800 should be classified as NCAs. We found that such a change could result in excessive mitigation because there may be areas where the HHI is high but where there is excess capacity. In such circumstances, it is more important to look at which supplier or suppliers are essential to meeting the market's needs than at the level of the HHI. However, we encouraged the IMM to monitor for situations where there is a high HHI and suppliers may be jointly pivotal to see if such areas are subject to substantial market power, and thus if they should be treated as NCAs.

b. Request for Rehearing

236. Midwest TDUs argue that the Commission wrongly rejected their arguments that areas experiencing a substantial, non-*de minimus* number of constrained hours per year, though less than 500, can present acute market power risks that merit the application of NCA thresholds. In their initial comments, they cited to the possibility of all 375 summer peak hours being congested, yet not meeting the 500 hour minimum for the NCA definition. In their rehearing comments they say that the relevant question is not whether

peak hours give rise to constraints, but whether NCA designation is needed for areas where constraints exist for less than 500 hours per year, such as during all of the summer peak hours, to protect customers from the exercise of market power. They point to a Commission statement in the Market Based Rates Order that "[c]onditions in peak periods can provide significant opportunity to exercise market power. As capacity is utilized to meet demand there is less available to sell on the margin and often less competition."[179]

237. Midwest TDUs also argue that the Commission erred in rejecting not only the HHI metric, but any metric that can assess the risk of coordinated interaction. Midwest TDUs claim that while it is important to look at more than just an HHI metric to assess supplier market power, an HHI (or some other measure of coordination risk) must be included. The Commission's rejection of such a metric is contrary to its finding in the Market Based Rates orders that measures of both unilateral and coordinated market power are needed, according to the Midwest TDUs.[180] Their rehearing request argues that even in a market with excess capacity, including at times other than system peak, the dominant seller(s) could raise prices by a significant amount if the capacity that is "excess" has marginal costs considerably higher than the competitive price at the given demand level. They contend that the Commission's concerns about excessive mitigation associated with measuring for collusion risk is unfounded, because Module D subjects sellers to mitigation only if they fail both the conduct and impact tests.

c. Discussion

238. As noted above, the Commission's obligation is to assure that rates are just and reasonable for both buyers and sellers. In applying mitigation, the difficulty is to set appropriate thresholds that balance under-mitigation and over-mitigation. Each has its costs. In particular, setting thresholds too high and thus under-mitigating the market means that some exercise of market power will not be mitigated or will not be fully mitigated. Setting thresholds too low results in over-mitigation, which could lead to more frequent intervention in the market, and that some competitive market results will be mitigated, decreasing market confidence and, therefore, investment in needed infrastructure.

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[179] Midwest TDUs Request for Rehearing at 63 (citing *AEP Power Marketing, et al.*, 107 FERC ¶ 61,018 at P 91 (2004)).

[180] *Id.* at 65 (citing *AEP Power Marketing, et al.*, 107 FERC ¶ 61,018 at P 88 (2004)).

239. Over-mitigation would mean that generators will not be able to recover all of the costs that they should, and generators may exit the market, or be less likely to enter. Even the threat of over-mitigation may keep market participants out of the market. Fewer competitors can mean less system flexibility and thus ultimately less reliability, and for this reason it is also appropriate to avoid over-mitigation. While the conduct and impact tests are designed to help protect against over-mitigation, by establishing bounds within which prices and quantities bid may vary, the lower thresholds associated with NCAs mean that the potential for over-mitigation increases when a specific area is designated an NCA rather than a BCA.

240. In separating out NCAs for tighter thresholds and thus increasing the potential for mitigation, in NCA areas the potential for exercise of market power is greater and tighter thresholds for mitigation are thus appropriate. It is important to realize that the questions that the Midwest TDUs raise involve the standard for which areas should be subject to the tighter thresholds for mitigation. Midwest TDUs cite to the potential case of congestion in all summer peak hours justifying the need for NCA status for an area with less than 500 hours of congestion in a year. Their premise appears to be that, while the hours are more limited, if such constraints occurred the costs would be very high. While the opportunities for the exercise of market power may be higher during peak periods, without congestion the possibility for the exercise of market power will still be very limited if congestion is not the norm. There is not a capacity shortage within the Midwest market as a whole, and without congestion there will be a multitude of potential sellers that will make the exercise of market power unlikely. As we also pointed out in the TEMT II Order, the likelihood of congestion in all summer peak hours is very low, as congestion is not usually related to peak hours as much as to plant and line outages. Thus, while the cost of the exercise of market power would be higher on peak, there is no indication that congestion would occur for anything close to all summer peak hours. We do not believe the potential for under-mitigating exceeds the potential for over-mitigating in this situation. We believe that the thresholds adopted are appropriate to assure just and reasonable rates for both buyers and sellers, and we deny rehearing on this issue.

241. In response to Midwest TDUs' refutation of the Commission's finding that the use of an HHI might not be appropriate because there may be excess capacity in the market, a competitive market result does not mean that a generator on the margin necessarily collects its own marginal cost; instead, it means that the generator can collect up to the marginal cost of the next available megawatt. In this manner, generators in the market are able to recover some of their fixed costs. Unless the actions of the generator cause a different generator to be the marginal generator, there is not necessarily a problem.

242. In assessing the applicability of, and need for, using the market share focus of the Market Based Rates assessment for mitigation in NCA areas, it is important to realize that the approaches differ both in the definitions they use and in how they are applied.[181] With the Market Based Rates assessment, if the supplier is found to be pivotal or dominant, it is not allowed to sell at market based rates, unless it makes a more detailed showing (a delivered price test) that it does not have market power. With Midwest ISO market power mitigation, if the area meets the definition for an NCA, NCA mitigation will not be automatically applied, but the generator will be subject to conduct and impact tests. If an area is found to not be an NCA, it may be subject to mitigation within a BCA when and if market power is exercised. A $1,000/MWh market-wide offer cap will apply, limiting all generators' bids within the Midwest ISO footprint. The differences in the definitions and the application of the two approaches mean that pieces of one should not automatically be used as precedent for the other, as suggested by the Midwest TDUs.

243. Another important difference between the approaches of the Market Based Rates determination and mitigation in the Midwest ISO is that, in the latter, there is an IMM that is established to provide independent, impartial and effective monitoring and reporting on, and mitigation for, the Midwest ISO's energy markets. The IMM does not currently see a need for a concentration or market share-based test for mitigation. Should the IMM see that need at some point in the future, or should it identify specific market areas as needing a greater degree of mitigation, such as that provided for NCAs, it can alert the Midwest ISO, stakeholders and the Commission to the need for such changes.

244. In answer to the Midwest TDUs' argument that there will not be any ill effect from over-mitigation from a changed NCA definition, due to the application of conduct and impact tests, we disagree. While the conduct and impact tests are likely to stop unnecessary mitigation, with lower thresholds over-mitigation becomes somewhat more

[181] In the Market Based Rates assessments, the pivotal supplier is defined as a supplier whose capacity is needed *on peak* to supply market needs, as demand cannot be met without its participation. The applicant itself must be a pivotal supplier or dominant in order to fail the test. A market share test of 20 percent is also applied during peak and non-peak periods, with those having such a market share of available capacity within the control area being found to be dominant. Under the mitigation provisions of the TEMT, for an NCA to be declared, a pivotal supplier is defined as being able to affect a transmission constraint, and a variety of market conditions including peak and non-peak are considered, unlike in the Market Based Rates pivotal supplier test. Non-pivotal suppliers may be found to be in an NCA, because only one supplier, not all, within the area would need to be found to be pivotal. *See* Module D, section 63.4.1, Original Sheet No. 757-61.

likely. Beyond this, however, there are other protections given to those within NCAs which should not be given without due consideration to other parties. Such protections include the expanded congestion cost hedges. For all of these reasons, we deny the Midwest TDUs' request to modify the NCA definition to include a collusion measure.

3. Reference Levels

a. Background

245. In the TEMT II Order, the Commission accepted the use of the following proposed methods, in sequential order, for calculating reference levels:[182] (1) offer-based, (2) LMP-based, and (3) consultative.[183] The consultative method, used when the others cannot be, determines the level in consultation with the market participant. It is intended to capture the unit's marginal costs, including legitimate risks and verifiable opportunity costs. The Commission ordered the IMM to make a filing that would more clearly specify what factors the IMM considers important in the marginal cost calculation in order to reflect legitimate risks and opportunity costs in establishing reference prices. The Commission also said that the IMM should also discuss how these costs are estimated for different output levels.

b. Requests for Rehearing

246. Ameren, in its rehearing request, says that because the IMM's knowledge about the Midwest ISO's market participants is almost entirely based upon the information those participants provide to the Midwest ISO and the IMM, the IMM is given authority over crucial matters for which it may have insufficient knowledge without the input of control areas. According to Ameren, this runs the risk that a particular company's units will be set at a reference level that might not accurately represent the appropriate unit parameters. Thus, asserts Ameren, a unit could be subject to mitigation for perfectly legitimate actions. Ameren claims that the better answer would be to make the control areas responsible for providing accurate data on the units. Therefore, Ameren recommends that the IMM should then consult with the control area and the market participant that owns the particular unit to establish the reference level, as is done on FTRs and asset registration.

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[182] Reference levels, based upon estimates of a generator's marginal costs including legitimate risks and opportunity costs, are the basis to which conduct thresholds are applied.

[183] TEMT II Order at P 300, 304.

247. Ameren also says that the subjective nature of defining risks and opportunity costs as permitted by the Commission is problematic. It argues that two units with the same unit parameters (start up time and cost, ramp rate, and minimum and maximum output levels…) may have different criteria in defining their unit parameters, and thus may end up with different reference prices. One way to avoid this situation, according to Ameren, would be to have the Commission clarify what it means by "legitimate risks and opportunity costs" and to require the Midwest ISO to establish and file clear criteria as to how reference levels will be set. This filing, states Ameren, would include more specific information beyond that pertaining to "legitimate risks and opportunity costs" that define with specificity how unit costs and any other factors that will be used to set the reference levels will be established.

248. Ameren also says that the Commission should clarify definitions and parameters to be used in undertaking the standardized survey and setting the initial reference levels, in order to provide for consistent reference levels among entities with similar cost structures.

c. Discussion

249. In the TEMT II Order, the Commission ordered the IMM to make a filing to more clearly specify what factors it considers important in the marginal cost calculation in order to reflect legitimate risks and opportunity costs in establishing reference prices. The Commission also said that the IMM should also discuss how these costs are estimated for different output levels. The IMM has provided information in the testimony of Dr. David Patton that accompanies the Midwest ISO's October 5 compliance filing. The compliance filing is the appropriate place to address specific concerns on this issue.

250. Moreover, the TEMT, in section 64.1.4, provides for consultation between the IMM and the market participant when the market participant believes the reference levels are not set appropriately, so we see no reason to modify this provision. To the extent that the IMM is unable to use the offer-based or LMP-based methods and it uses the consultative process, and if it needs to consult with control area operators to determine the appropriate reference levels, we expect it to do so.

4. Prospective Application of Mitigation

a. Background

251. In the March 13 Order, the Commission rejected tariff provisions that included automated mitigation procedures (AMP), finding those provisions to be premature given the IMM's determination that they are not necessary at the beginning of Day 2

operations, and the IMM's lack of software for such procedures.[184] The Commission stated that its rejection of the procedures was without prejudice to a future filing to implement such provisions when the IMM determines that they are necessary.

252. In the TEMT II Order we responded to concerns raised by Southwestern and the Midwest TDUs about the prospective application of AMP in the day-ahead market, which leaves a full day before day-ahead bids are mitigated. We found that while real-time markets could mitigate much of the potential for the exercise of market power, there remained the possibility for the unmitigated exercise of market power. For this reason, we directed the IMM to devise appropriate tariff language for the Midwest ISO to file in its compliance filing to implement an automatic mitigation procedure or other measures (such as manual expedited mitigation) to prevent the one-day lag in mitigation that would otherwise occur in the day-ahead market.

b. Request for Clarification

253. The IMM filed a request for clarification on September 13, 2004. In its clarification, the IMM agreed with the Commission's goal of preventing a one-day lag in mitigation. However, the IMM stressed that focusing on this goal in isolation conflicts with other priorities that the Commission has established for competitive energy markets.

254. In particular, the IMM says that automating the conduct and impact screens in the day-ahead market is not presently feasible, given the current performance of the day-ahead software and limited time available from the deadline for the submission of offers to the deadline for Midwest ISO to post day-ahead market results. The IMM claims that TDUs refer to the automation in NYISO as evidence that the technical hurdles, if real, can be overcome. However, according to the IMM, the NYISO market employs a software package that is more adaptable to a day-ahead AMP mechanism, and they run it for a much smaller market. The IMM asserts that the size of the Midwest ISO market, combined with software limitations at start-up, would make it impossible to run a conduct test and then an impact test, and still rerun the model to produce a new set of market clearing prices and quantities in time to post prices by the established deadlines. The IMM also points to the fact that the TEMT II Order has already required that the Midwest ISO run the market two hours faster than it had proposed, by moving back the deadline for submitting bids from 900 EST to 1100 EST for the day-ahead market.

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[184] *See* March 13 Order at P 105.

255. The IMM explains that it has been working to develop alternatives for applying the conduct and impact tests in the day-ahead market, such as expedited manual mitigation procedures, and believes these alternatives would require retroactive revisions of day-ahead schedules two or more hours after prices are initially posted. The IMM contends that making prices preliminary only would cause uncertainty about schedules and prices in most periods.

256. The IMM states that delays or retroactive mitigation might be avoided by using simplified standards for mitigation, for example, by mitigating all bids that fail the conduct test without regard to the impact on market results. However, according to the IMM, this would result in over-mitigation, as there are often instances of violations of the conduct test that do not result in market impacts. The IMM asserts that the use of a manual expedited mitigation technique, such as using some truncated form of conduct and impact tests, will invariably increase the potential for mitigation of behavior that does not warrant mitigation. According to the IMM, the use of a second-best mitigation mechanism might have merit if a pattern of behavior likely to have significant market power impacts is anticipated. However, the IMM says that at present, there is no reason to anticipate such a pattern of market power abuse in the day-ahead market. Thus, the IMM states, as a routine protective measure, a manual expedited mitigation technique would pose a threat of market distortion that would entail greater harm than likely abuses of market power.

257. The IMM is currently working with the Midwest ISO to develop a workable mitigation mechanism for the day-ahead market. However, it says that any effort to develop the software enhancements to comply with the Commission's requirement would divert limited resources from getting the Midwest ISO market started. The IMM claims that the protections afforded by the real-time market and virtual trading will substantially limit the potential for significant harm, and thus, the Commission should not make the removal of the one day lag in day-ahead mitigation a priority at this point in time.

c. Discussion

258. While we understand the IMM's concerns about adopting automated mitigation or expedited manual mitigation for the day-ahead market (to commence when the market opens), we remain concerned that the current proposal may allow for the unmitigated exercise of market power. We share the IMM's assessment that mitigation in the real-time market will significantly dampen the ability of market participants to exercise significant market power in the day-ahead market. However, we are not confident that it entirely eliminates the possibility of the exercise of market power, and we do not take that possibility lightly.

259. Given the other tasks facing the IMM in this short time frame, the Commission's change in position on this issue, and the IMM's concerns about the possibility for harm in instituting manual mitigation, however, we will permit the IMM to delay adoption of automated mitigation or expedited manual mitigation for the day-ahead market. Nevertheless, because our concern remains on this issue, we will require the IMM to take other actions until this issue is resolved. First, we will require the IMM to file quarterly reports to show where mitigation would have been applied were there not a lag in mitigation, and the associated dollar impact on the market. Second, we will require the IMM to develop and file a safety-net plan for instituting mitigation if a pattern of behavior develops in the day-ahead market in which mitigation is repeatedly needed but cannot be applied due to the lag. Third, the IMM must file a plan and associated timeline under which it will resolve this problem for the longer term by instituting automated or expedited manual mitigation in the market.

5. Sanctions

a. Market Rule 2

i. Background

260. In the Sanctions section of the TEMT II Order, the Commission ordered that since all market-based rate sellers in the Midwest ISO's markets are subject to the Commission's Market Behavior Rules, the Midwest ISO must include the Commission's Market Behavior Rule 2, as applicable, in its tariff.[185] Market Behavior Rule 2 prohibits "actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules…"[186] By including the rule in the Midwest ISO's tariff, the Commission stated that it will have included a strong general anti-manipulation standard that, due to the uniformity of its language, in sellers' tariff's and other ISO tariffs, will help us to develop

[185] TEMT II Order at P 356.

[186] *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 at P 35 (2003) (Market Behavior Rules Order), *order on reh'g* 107 FERC ¶ 61,175 at P 8 (2004) (Market Behavior Rules Rehearing).

clear rules and interpretations of the standard bringing certainty to the market. Violations of this rule would be subject to refund. In the TEMT II Order, the Commission stated that any violations of this provision of the tariff identified by the IMM should also be referred to the Commission.[187]

ii. Requests for Rehearing

261. Cinergy seeks rehearing of the Commission's requirement that the Midwest ISO include Market Behavior Rule 2 in its tariff. Cinergy says that Market Behavior Rule 2 invokes no established criteria or legal benchmarks, and that it is unconstitutionally vague in that its prohibitions are unlimited and unknowable. Cinergy points out that the Commission acknowledges that the rule is neither specific nor fully formed, stating that the rule is a "strong *general* anti-manipulation standard" and that the Commission intends to "develop clear rules and interpretations of the standard" in the future.[188] Cinergy says that it is improper to require the imposition of "an overbroad, ambiguous, and admittedly underdeveloped standard into the Midwest ISO tariff," and argues that market participants have a constitutional right to operate under specific strictures.[189]

262. Cinergy goes on to argue that if Market Behavioral Rule 2 is incorporated into a Commission-filed tariff, it improperly creates the potential for retroactive refund liability for settled transactions. In addition, neither section 205 nor 206 of the FPA allows the Commission to enact vaguely-worded tariff conditions, to be defined at some future date. Cinergy states that no part of the FPA allows the Commission to impose its developing case law retroactively, accompanied by retroactive penalties. Cinergy states that instead, section 206 gives the Commission the authority to change the existing rate or tariff provision only prospectively from sixty days after the filing of a complaint or initiation of an investigation.[190]

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[187] TEMT II Order at P 356.

[188] Cinergy Request for Rehearing at 54-55 (citing TEMT II Order at P 356 (emphasis added)).

[189] *Id.* at 55 (citing the finding in *Grayned v. Rockford*, 408 U.S. 104, 108 (1972), that "an enactment is void for vagueness if its prohibitions are not clearly defined.").

[190] We note that the TEMT is not an existing rate or tariff, but is a newly-filed tariff that we are first considering in this proceeding and that will not become effective until March 1, 2005.

iii. Discussion

263. Cinergy has raised virtually all of its rehearing arguments in the Market Behavior Rules proceeding, as they go to Market Behavior Rule 2 itself and not its inclusion in the TEMT, and so we will dismiss those arguments in this proceeding as a collateral attack on the Market Behavior Rules orders. We will address only Cinergy's challenge to including Market Behavior Rule 2 in the TEMT as the only issue arguably properly raised in this proceeding.

264. We again find that including Market Behavior Rule 2 in the Midwest ISO tariff is entirely appropriate. This rule provides fundamental guidance for the conduct of holders of market-based rate authority. As the Commission found in the Market Behavior Rules Rehearing:

> While sellers need and deserve regulatory certainty and transaction finality, the Commission, in the performance of its statutory duties, cannot be impaired in its ability to provide remedies for market abuses whose precise form and nature cannot be envisioned today. . . . [O]ur Market Behavior Rules strike this necessary balance in a way that will both protect market participants and promote competition in the wholesale electricity markets.[191]

265. The Market Behavior Rules Order adopted the proposed Market Behavior Rules as a *pro forma* condition to all new and existing market-based rate tariffs, and the Market Behavior Rules Rehearing upheld this finding.[192] In a February 20, 2004 order, the Commission directed the CAISO to modify the behavior rules it proposed to add to its OATT, to make them consistent with the Market Behavior Rules.[193] An October 28, 2004 Commission order found that the CAISO had conformed most aspects of its

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[191] Market Behavior Rules Rehearing at P 8.

[192] *See* Market Behavior Rules Order at P 3, 11 (finding sellers' existing market-based rate tariffs and authorizations unjust and unreasonable without clearly-delineated rules to govern market participant conduct); Market Behavior Rules Rehearing at P 1-6.

[193] *See California Independent System Operator Corporation*, 106 FERC ¶ 61,179, *order on reh'g*, 107 FERC ¶ 61,118 (2004), *reh'g denied* 109 FERC ¶ 61,089 (2004).

proposed Enforcement Protocols to the Market Behavior Rules; however, the Commission instituted an FPA section 206 proceeding to conform proposed Enforcement Protocol 5 to Market Behavior Rule 3.[194]

266. Cinergy's argument that Market Behavior Rule 2 should not be included in the TEMT makes little sense in light of the Commission's express purpose in creating the Market Behavior Rules. The Commission sought to "provide regulatory safeguards to ensure that customers are protected from market abuses,"[195] and proposed that the Market Behavior Rules apply "to any market-based rate sale, whether in the bilateral market or in an organized market, *i.e.*, in the bid-based markets administered by RTOs or by an ISO."[196] By this definition, the TEMT – which provides the terms and conditions under which entities may transact in the Midwest ISO's energy markets – can and should include Market Behavior Rule 2.

b. Dispute Resolution Procedures

i. Background

267. Section 67 of Module D contains dispute resolution procedures which a market participant can invoke if it has reasonable grounds to believe that it has been adversely affected because a mitigation measure has been improperly applied or withheld. A determination will then be made as to whether the imposition of a mitigation measure was or would have been appropriate. The TEMT II Order did not require any changes to be made to the dispute resolution procedures.

ii. Requests for Rehearing

268. AMP-Ohio says that section 67, the Dispute Resolution section of Module D, contains several ambiguities which the Commission did not address in the TEMT II Order. In particular, the use of the term "may be withheld" in saying that a financial penalty may be withheld pending the resolution of the proceeding etc., does not explain who makes the choice. AMP-Ohio also asserts that section 67 should not allow for

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[194] *California Independent System Operator Corporation*, 109 FERC ¶ 61,097 (2004).

[195] Market Behavior Rules Order at P 4.

[196] *Id.* at P 175 (citing *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 103 FERC ¶ 61,349 at P 8 (2003)).

payments to a generator that was improperly mitigated, if its mitigated bid did not clear. AMP-Ohio also requests that the Commission clarify that compensation for improper mitigation is not in addition to payments already received for generation supplied to the market.

269. The Commission agreed with AMP-Ohio in the TEMT II Order that it would be a good idea for the IMM to report any improper mitigation and the associated costs. AMP-Ohio says that if it is a good idea, it should be required.

iii. Discussion

270. We understand section 67.b to mean that the entity subject to the penalty may choose to withhold the penalty pending the resolution of the proceeding. In the case of payments to generators whose (mitigated) bid did not clear, and that were improperly mitigated, AMP-Ohio's requested language is not needed, as a bid will not be mitigated unless it is accepted in the market. If AMP-Ohio means that payments should not be made to an improperly mitigated generator whose mitigated bid was accepted but did not set the market-clearing price, we disagree. Section 67.d provides that if a market participant's bid is improperly mitigated, the market participant will be compensated at the higher of the LMP or its full as-submitted bid for all intervals during which its bid was improperly mitigated. This provision appropriately ensures that the market participant will be put in the same position it would have been in the absence of the improper mitigation. With respect to AMP-Ohio's request for clarification that compensation for improper mitigation is not in addition to payments already received for generation supplied to the market, we agree that if a generator has already received some payment (the default offer), any additional payment would be the difference between (1) the higher of the LMP or the as-submitted offer, and (2) the initial payment. However, we do not believe the tariff needs to be modified, as we read it as specifying that the total compensation (rather than the additional compensation) would be the higher of the LMP or the as-submitted offer.

271. We do not believe that reporting on levels of compensation for improper mitigation needs to be an explicit requirement for the IMM. There are many factors in the market that the IMM should be watching and reporting on. The IMM monitors for improper mitigation, and should report to the Commission, and propose new rules if necessary, if and when it perceives problems with improper mitigation.

6. Posting Cost-Based Bid Data After Six Months

a. Background

272. In the TEMT II Order, the Commission found that appropriately masked bid and offer data should be made available to market participants, after a 6-month delay, in order to provide market transparency. The TEMT II Order established that "…market participants need access to bid and offer data; however, we find that such data should not be available immediately after bidding because of the potential it offers for collusion. Instead, as in PJM, NYISO and ISO-NE, the data should be made available only after a six-month delay and should have participants' names masked, as they are in NYISO."[197]

b. Requests for Rehearing

273. Several parties object to the disclosure of individual generator cost data during the cost-based bid transition period. Cinergy contends making this information public threatens the competitive position of generators and ultimately threatens the competitive markets the Commission is promoting.[198] Cinergy requests clarification that the Midwest ISO is not authorized to disclose this information in a way that shows the identity of the generator.

274. Similarly, Detroit Edison states that disclosure of sensitive generator cost information could significantly damage the integrity of the market at its inception. Detroit Edison avers that the Commission should provide enhanced protection for cost-based bid data; for example, it states that access should be limited to the Commission and the IMM and denied to competitors.

275. Dynegy notes that the Commission required the Midwest ISO to work with stakeholders to more closely align its confidentiality provisions with PJM's.[199] Given that PJM has no provisions providing for the release or public dissemination of cost-based energy bids, Dynegy requests clarification that cost-based bids will never be subject to release or public dissemination.

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[197] TEMT II Order at P 559.

[198] Cinergy Request for Rehearing at 21 (citing *Reporting of Natural Gas Sales to the California Market*, 96 FERC ¶ 61,119 at 61,467-68 (2001)).

[199] The Midwest ISO's confidentiality proposal will be discussed in more detail *infra* at section IV.J.3.a of this order.

276. Ameren believes that the Commission is headed in the right direction in requiring the release of bid data. However, it says that this may not be adequate to protect market participants from the disclosure of confidential and commercially sensitive information that can harm their ability to buy or sell power and to participate in the Midwest ISO's energy markets. Ameren points to the requirement in the TEMT II Order that market participants submit cost-based bids for generation resources into the day-ahead market, RAC and real-time market for two months following the start of the Day 2 market. The combination of the cost-based bidding requirement and the release of bid and offer data, may allow parties to determine the identity of the participant who has submitted the cost-based bids, even if the participant's name is otherwise masked. The use of a six-month non-disclosure period may be inadequate to protect a participant from harm if its identity can be determined. Accordingly, Ameren argues that the Commission should require that the information pertaining to cost-based offers remains undisclosed indefinitely.

277. Ameren also argues that if the Commission determines that any such information should be released, the disclosure should not distinguish between virtual and physical bids. Because physical bidders must own or control a unit, it can be easier to determine the identity of a physical bidder if any type of asset specific information is released.

c. Discussion

278. The Commission will not require the disclosure of the cost-based bids required at market start-up. The requirement for cost-based bidding minimizes the potential for gaming of bids, and thus public disclosure of such bids is not necessary. We clarify that the delayed release of bid data should not include those offers at market start-up that the Commission required to be cost-based. Of course, cost-based bid information will be available to the IMM and the Commission for review.

279. With respect to the identification of bids as physical versus financial, we agree that the public disclosure of bids should not include whether individual bids were physical or virtual bids. However, we clarify that the IMM can provide information to the Commission about physical and virtual bids on an aggregated basis, as issues arise regarding these bids or as the Commission orders. For example, such information might include number of bids, associated volumes, average price bid, etc.

7. Persons and Entities Subject to the Market Mitigation Plan

a. Background

280. Section 50.3 of the tariff provides that the Midwest ISO, the IMM, and any person or entity participating in any of the Energy Markets or that takes service under or is a party to any tariff or agreement administered by the Midwest ISO shall be subject to the

terms, conditions, and obligations of the Independent Market Monitoring Plan included in Module D of the TEMT.

b. Requests for Rehearing

281. On rehearing, Cinergy refers the Commission to the red-line tariff it provided along with its original comments. Cinergy proposes the following revisions, shown in brackets:

> Section 50.3: **Persons and Entities Subject to the Plan**
>
> The Transmission Provider, the IMM, and any person or entity participating in any of the Energy Markets or that takes service under or is a party to [delete "any"][this] tariff or agreement[s listed in Attachment P of this tariff][delete "administered by the Transmission Provider"] shall be subject to the terms, conditions and obligations of this Plan.[200]

Cinergy says that without this change the provision is overly broad, and that the provision should only apply to this tariff.

c. Discussion

282. We consider the proposed revisions to be reasonable since they more specifically and accurately define the authority of the Transmission Provider and the IMM to monitor the energy markets and administer the Market Mitigation Measures. Accordingly, we direct the Midwest ISO to make the proposed revisions.

G. System Supply Resources, Demand Response Resources, Offer Caps and Emergency Procedures

1. System Supply Resources

a. Background

283. The Commission accepted the Midwest ISO's System Supply Resources (SSR) program as "a reasonable backstop measure to assure reliability in markets to be operated

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[200] *See* Cinergy Request for Rehearing at 61 (citing its Protest at Exhibit CIN-2 (May 7, 2004)).

by the Midwest ISO."[201] The Commission further stated that the program was consistent with its policy on reliability compensation issues and accepted the approach for negotiating and assigning SSR costs.

b. Requests for Rehearing

284. Four parties request rehearing of the SSR program for a variety of reasons. Coalition MTC claims that the program is not consistent with the Commission's policy on reliability compensation issues because it is not activated by a well-defined triggering event. Its comments focus on the TEMT II Order's summary description, which noted that the Midwest ISO expected the SSR program to be activated principally by a need for reactive power. Coalition MTC also argues that statements made by the Midwest ISO in another proceeding that a needs test for reactive power is superfluous[202] undermines any basis for evaluating whether SSR status is required for any generator seeking to retire, and implies that every generator would always qualify for SSR status. For this reason, Coalition MTC requests that the TEMT proceeding be consolidated with the proceeding addressing proposed Schedule 21 for reactive power. Finally, Coalition MTC requests clarification that parties can challenge any section 205 filings that the Midwest ISO submits to recover costs for SSR.[203]

285. Ameren objects to the SSR program because it interferes with the property rights of public utilities and may be counter to the best interests of market participants or its ratepayers. Additionally, Ameren contends that this would give Midwest ISO, in effect, more authority than that of the Commission and there is no prior Commission authorization needed under the FPA to take a unit out of service. The premise of the program inappropriately presumes that entities, such as Ameren, will act in a way that may harm reliability and it gives to the Midwest ISO too much authority to dictate the terms of any contract.[204]

286. Cinergy raises three basic objections to the SSR program: (1) it is not purely reliability-driven; (2) it could conflict with other binding directives; and (3) it does not

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[201] TEMT II Order at P 370.

[202] Coalition MTC Request for Rehearing at 14 (citing Docket No. ER04-961-000, Direct Testimony of Jeffrey R. Webb at 4 (June 25, 2004)).

[203] *Id.* at 15.

[204] Ameren Request for Rehearing at 6-8.

guarantee full compensation.[205] It believes that a voluntary program would be preferable. In the alternative, a mandatory program should at least offer greater clarity that SSR generators will be fully compensated, identify alternatives to the SSR designation, and provide for expedited Commission review at the option of the owner. Cinergy emphasizes, in particular, that the SSR designation must not conflict with other applicable laws. For example, Cinergy is fearful that units that need to shut-down to install environmental compliance equipment could run afoul of SSR requirements.

287. Manitoba Hydro argues that the SSR provisions should only apply to generation resources within the Midwest ISO region, or alternatively, to establish for whom the Midwest ISO acts as Reliability Authority under a contract granting such authority to the Midwest ISO. Manitoba Hydro states that it is subject to the jurisdiction of other authorities that prevent it from complying with Midwest ISO directions on operating limits, transmission maintenance plans, generator outages and decommissioning resources.[206]

c. Discussion

288. We deny rehearing. With respect to Coalition MTC's arguments, the SSR program is triggered by a specific event – a decision to retire a unit that is needed for reliability. Contrary to Coalition MTC's characterization, SSR is not a program for acquiring or assessing reactive power needs generally. The SSR program is designed only to meet a short-term reliability need that would be precipitated by a generator retirement. Accordingly, no purpose would be served by consolidating this proceeding with our proceedings in Docket No. ER04-961-000 to develop an Independent Power Producer reactive power program. Moreover, the Commission rejected proposed schedule 21 in favor of the Midwest ISO refiling to place all reactive power providers under schedule 2.[207] However, we share the concerns of parties that certain provisions in the SSR program could be interpreted as open-ended obligations and therefore could result in a major long-term program with significant and long-term commitments for owners of generating units. As we indicated in the TEMT II Order, we approved the SSR program as a back-stop measure only and therefore expect the contracting for SSRs to be limited and of short duration. Such an approach provides a balance between the Midwest

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[205] Cinergy Request for Rehearing at 24-32.

[206] Manitoba Hydro Request for Rehearing at 10-11.

[207] *Midwest Independent Transmission System Operator, Inc.*, 109 FERC ¶ 61,005 (2004).

ISO's need to manage reliability and the need of generation owners to manage their assets efficiently and according to their business plans. To ensure that our objective is factored into the SSR program, we will require the Midwest ISO to provide a report as part of its section 205 filing for an SSR contract that details the alternatives the Midwest ISO evaluated, the estimated earliest termination date for the SSR, and how it will manage reliability once the SSR contract is terminated and the unit is retired.

289. In regards to the argument that parties should be free to challenge any section 205 filings under the SSR program, we note that nothing here affects parties' already existing rights under section 205.

290. The SSR program is a backstop measure to protect reliability because markets are not yet complete and have no specific reliability product or comprehensive demand response at this time. The SSR program is not an indication that entities, such as Ameren, would act intentionally to harm reliability. The program recognizes that a private decision to retire a unit could have consequences for region-wide reliability that the Midwest ISO must evaluate. However, the evaluations are not expected to translate into SSR contracts except in limited circumstances. We find the limited backstop provided by the SSR program is a prudent measure for market start-up. The Commission finds it appropriate that SSR units should be fully compensated because of the Midwest ISO's SSR designation. Furthermore, the Midwest ISO's alleged "authority" to determine the terms of the contract is acceptable in that the contracts are subject to challenge before, and review by, the Commission.

291. We agree with Cinergy that market participants may wish to retire a unit or take a unit out of service temporarily for environmental or other valid reasons. The SSR program would interfere with such decisions generally only when those decisions create a short-term reliability problem. SSR designation is a limited, last-resort measure. If SSR requirements necessitate expensive retrofits, nothing in the SSR program would require a generator to absorb any uncompensated going-forward costs. Clearly, reasonable and prudent costs for repairs or upgrades needed to meet applicable environmental regulations or local operating permits that would not be incurred otherwise should be fully recoverable under any resulting SSR contract. Finally, we agree with Cinergy and Manitoba Hydro that SSR designations cannot be imposed if continued operations of a plant would be contrary to applicable law, regulations, court or agency orders, such as a settlement with an environmental agency or a consent decree approved by a court.

292. We do not agree that the SSR program could conflict with other binding directives, presumably environmental requirements. We agree with Cinergy and Manitoba Hydro that SSR designations cannot be imposed if continued operations of a plant would be contrary to applicable law, regulations, court or agency orders, such as a settlement with an environmental agency or a consent decree approved by a court. The

Commission has previously allowed generators to satisfy their obligations to offer power into bid-based energy markets by offering to sell the maximum amount of energy that they can produce without violating their operating permits.[208] While the Midwest ISO's SSR proposal is distinct from the CAISO's "must offer" rule, the principle of our decision regarding CAISO "must offer" limits is the same as here: generators must not be required to operate in violation of other applicable restrictions on their operations.

293. Finally, we emphasize that all SSR units should be fully compensated for any costs incurred because of their extended service. For example, nothing in the SSR program would require a generator to absorb any uncompensated going-forward costs. Clearly, reasonable and prudent costs for repairs or upgrades needed to meet applicable environmental regulations or local operating permits that would not be incurred otherwise should be fully recoverable. We share Cinergy's concern that SSR obligation could be too open-ended and, as noted above, will require the Midwest ISO to provide details on alternatives to the SSR designation.

2. Demand Response Resources

a. Background

294. Subject to further explanation and clarification, the Commission accepted the Midwest ISO's Demand Response Resources (DRR) program.[209]

b. Requests for Rehearing

295. LG&E and Steel Producers request rehearing of the DRR program. LG&E argues that the program impermissibly allows retail load in non-retail wheeling states to be paid by the wholesale market to decrease demand.[210] LG&E wants to make sure that non-retail-wheeling states will be allowed to prohibit their retail customers from participating as a DRR. Steel Producers want the DRR program expanded in several ways to enhance its value to end-use customers such as themselves.[211] Steel Producers argue that the

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[208] *See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated By the California Independent System Operator and the California Power Exchange*, *et al.*, 99 FERC ¶ 61,205 (2002).

[209] *See* TEMT II Order at P 376-77.

[210] LG&E Request for Rehearing at 21-23.

[211] Steel Producers' Request for Rehearing at 2-4.

following three points were raised in their original protest but not addressed by the Commission. First, they want to be eligible to participate as a DRR as long as they can respond to dispatch instructions within 10 minutes instead of the proposed 5-minute response time. Second, they want clarification that they can participate as a DRR directly and not through an intermediary. Third, they want a share of system-wide benefits which they describe as benefits from lower LMPs and greater reliability.

c. Discussion

296. Demand response is a critical element of an efficient electric market, particularly in an emergency. The Midwest ISO's DRR program recognizes this importance and has made significant progress in laying out a plan for including DRRs comparable to generation resources in its markets. As demand response increases, wholesale electric markets become more reliable and wholesale prices become less volatile. However, only entities that participate directly in wholesale markets have the opportunity to participate as a DRR. We do not construe the Midwest ISO's definition as permitting LG&E's retail customers to participate directly in wholesale markets as a DRR. In non-retail-wheeling states, load-serving entities, such as LG&E, could serve as curtailment service providers and submit demand reduction bids on behalf of their retail customers, if they have state-jurisdictional retail demand response programs in place. The sharing of TEMT demand reduction revenues with those retail customers would remain state-jurisdictional. Thus, we direct the Midwest ISO to clarify its DRR definition as LG&E originally proposed.

297. We deny Steel Producers' request for rehearing. Response times required for dispatch instructions are determined by reliability needs and overall operating requirements, and there is no justification to change this parameter to benefit one category of resource. All direct wholesale customers may participate in the DRR program directly. However, such direct participation may not be possible for consumers in non-retail access states. To the extent Steel Producers are asking for authority for retail customers to circumvent non-retail access rules, we deny rehearing. We reject the argument that DRRs should be entitled to a share of system-wide benefits. In a competitive market environment, buyers who can respond directly to price are entitled to any savings realized from reducing their purchase only. The fact that their reduced consumption, along with that of other market participants, may contribute to a lower market-clearing price that benefits all consumers does not entitle them to additional benefits.

3. Offer Caps

a. Background

298. The Commission accepted the Midwest ISO's proposal for a $1,000/MWh safety-net bid cap to maintain price stability during a transition period before a comprehensive and permanent resource adequacy plan has been implemented.[212]

b. Requests for Rehearing

299. Several parties seek rehearing of the Commission's acceptance of the Midwest ISO's $1,000/MWh safety-net bid cap. Cinergy argues that any cap is inappropriate, especially when there is no mechanism for compensation for installed capacity, and reiterates its willingness to accept a previously agreed-to $5,000/MWh cap as a three-year compromise.[213] Cinergy believes that price spikes between $5,000/MWh and $7,000/MWh in June 1998 were instrumental in attracting needed investment and that some units must be able to bid well above $1000/MWh in severe tight supply/demand situation to recover fixed investment costs. It offers testimony from Dr. Tabors, who expresses concern that the reduced safety-net bid cap may discourage investment in the near- to medium-term time frame even though there is an increasing reserve margin and the proposal is only interim. Dr. Tabors could only support a lower safety-net bid cap if a functional installed capacity market was in existence. Cinergy interprets a recent Commission decision[214] and Chairman Wood's concurring statement thereto,[215] as supporting an explicit tradeoff between safety-net bid caps and compensation for installed capacity—a higher safety-net bid cap is required when there is no mechanism for compensation for installed capacity. Finally, Cinergy argues that, as stated in their protest, any bid cap should sunset after no more than three years.

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[212] *See* TEMT II Order at P 380.

[213] Cinergy Request for Rehearing at 49.

[214] *California Independent System Operator Corporation*, 105 FERC ¶ 61,140 at P 214 (2003).

[215] *Id.* (Wood, Chairman, concurring).

300. PSEG makes essentially the same point, raising the concern that imposing the $1,000/MWh safety-net bid cap that applies in other markets without also adopting an appropriate capacity market structure will unjustifiably reduce generators' ability to receive scarcity prices.[216]

301. LG&E also argues that the Commission has not justified the lower safety-net bid cap by pointing to comparable bid caps in PJM, NYISO and ISO-NE.[217] These other markets also have functioning capacity markets that provide an important source of revenue while the Midwest ISO does not.

c. Discussion

302. We deny rehearing. We agree with Cinergy, LG&E, and PSEG that an acceptable market design must give efficient generators a reasonable opportunity to recover costs, including fixed investment costs and a competitive rate of return. Generators may receive revenues from various sources, including spot markets for energy and operating reserves, bilateral contracts, and in some cases, retail rate base. A compensation mechanism for installed capacity or a revenue source for resource adequacy is also important although the Midwest ISO does not yet have such a mechanism in place. We find, however, that the proposed $1,000/MWh bid cap is a reasonable safeguard for the start-up of the Midwest ISO's markets. As we stated in the TEMT II Order, the decision to accept the $1,000/MWh bid cap is essentially a pragmatic one that takes into account the current state of the Midwest ISO's markets and the various market design elements.[218] We will continue to evaluate the markets to determine whether further adjustments are warranted, including whether the safety-net bid cap should be lifted entirely at some future date. We will not make that determination, as Cinergy requests, at this time.

303. Although the Midwest ISO has not yet developed a capacity market, we find that sufficient opportunity for cost recovery and incentives for new investment are available for the present situation characterized by increasing reserve margins. An opportunity to earn revenues from a capacity market will reduce the need for generators to rely on energy markets, but the relationship between a specific energy market safety-net bid cap and features of a specific capacity market are a matter of judgment. We disagree with Cinergy that price spikes, comparable to those experienced in 1998, are required to

[216] PSEG Request for Rehearing at 9.

[217] LG&E Request for Rehearing at 26.

[218] TEMT II Order at P 380.

induce investment. Even the investment community has acknowledged that long-term contracts are the single most essential requirement for obtaining financing for new generation.[219] Investment in the Midwest ISO's market area may be weak in the near term and some planned capacity additions may not materialize, but we see no reason to conclude that a $1,000/MWh bid cap would be a major cause of this outcome.

4. Emergency Procedures

a. Background

304. The Commission accepted the proposed emergency procedures subject to certain modifications.[220]

b. Requests for Rehearing

305. The IMM requests clarification "that the TEMT [II] Order was not intended to prohibit the Midwest ISO from dispatching emergency resources or operating reserves, or from setting prices at levels appropriately reflecting scarcity under conditions when DRRs or non-emergency output ranges (i) are not available due to timing issues, or (ii) are not the most efficient alternatives."[221] The IMM notes that the emergency range of a generator is a useful distinction because it is often associated with operating conditions that differ from the normal range and that may affect availability. The IMM wants to make certain that the Commission did not intend that these emergency operating

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[219] *See* remarks of Frank Napolitano, Lehman Brothers, Inc.; Jonathan Baliff, Credit Suisse First Boston Corporation; and Howard Newman, Warburg Pincus LLC, *Compensation for Generating Units Subject to Local Market Power Mitigation in Bid-Based Markets,* Docket No. PL04-2-000, Technical Conference, Tr. at 7-8, 38, 108-12, 219-21 (February 4, 2004). *See also PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112 at P 20 (2004) (citing these remarks and stating that the Commission is ". . .mindful of the comments made to us by representatives of the financial community, that dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure. A clear preference for long-term contracts and/or reliable revenue streams was stated.").

[220] *See* TEMT II Order at P 387.

[221] IMM Request for Clarification at 14-15.

parameters be ignored in making dispatch decisions. Similarly, the IMM wants to make certain that the Commission did not intend to direct that the dispatch of DRRs ignore timing issues in deciding whether it was appropriate to dispatch them.

c. Discussion

306. The Commission grants the clarification. The TEMT II Order was never intended to prohibit efficient actions on the part of the Midwest ISO. The discussion relating to emergency ranges of generators only intended to emphasize that labels are not definitive determinants of the economics of a particular resource. As the IMM points out, different operating ranges may be associated with very different costs, in part attributable to risk of failure, which should be taken into account. A least-cost option is not an option if the unit is unavailable or cannot be used because of a timing problem. However, the definition of “emergency range” for any particular unit is not always associated with a specific operating risk or feature that would always make it less efficient than non-emergency operating ranges of other types of units.

H. Resource Adequacy Requirements

1. General Proposal

a. The Interim Plan

i. Background

307. The Commission generally approved the Resource Adequacy Requirements (RAR) filed by the Midwest ISO in Module E of the TEMT. The requirements in Module E are meant to apply in the interim period from March 1, 2005 until the Commission approves a permanent plan filed by the Midwest ISO that has been fully vetted through the stakeholder process.

308. Module E relies on the pre-existing reliability mechanisms of the states and Regional Reliability Organizations within the Midwest ISO region and contains a default 12 percent annual reserve margin for areas where the Midwest ISO determines that no reserve standard is in effect.

309. Resources that market participants identify as available to meet their respective RAR must comply with the Module E requirements for designation as a Network Resource. Designation as a Network Resource requires ownership or its contractual equivalent, registration of the resource with the Midwest ISO, and a determination that it is deliverable to load within the Midwest ISO region. To ensure deliverability, network customers must make a request for Network Integration Transmission Service for new

Network Resources, and the Midwest ISO will conduct a System Impact Study that considers the delivery of aggregate resources of network customers to the aggregate of network load.

ii. Requests for Rehearing

310. Coalition MTC asks for clarification that the Commission is not mandating a particular model for the long-term RAR plan that the TEMT II Order directed the Midwest ISO to develop and file.

311. Detroit Edison requests the Commission to clarify the qualifications for DNR status by requiring that the resource be clearly identifiable (*e.g.*, a specific plant or portion of the system), be committed to the party requesting designation, and be demonstrably deliverable on a non-interruptible basis. Furthermore, they request a Commission directive to the Midwest ISO to provide details on the interim plan within 30 days given the fast-approaching March 1, 2005 market start date.

312. The Midwest TDUs request rehearing on numerous issues in Module E, including: the deliverability of network resources, behind-the-meter generation, the must-offer requirement, the treatment of existing state standards, and use of the term “load.”

313. Specifically, the Midwest TDUs are concerned about the Midwest ISO’s plans to validate network resources, as laid out in section 69.1.2.b, by using aggregate deliverability, rather than load-specific deliverability. The Midwest TDUs argue that this section is not clear and that the Midwest ISO may be counting on Network Resources deliverable to the aggregate Midwest ISO load that are not actually deliverable to the load of the customer claiming the resource as reserves. The Midwest TDUs argue that this does not make sense because a resource deliverable in Kentucky could count as reserves for WUMS Load-Serving Entities. Furthermore, the Midwest TDUs note that section 69.1.2.b could conflict with a number of state and Regional Reliability Organization RARs. The Midwest TDUs note that while the aggregate deliverability standard has been the norm in the eastern RTO and ISO markets, it has come into question lately from a load pocket perspective.

314. The Midwest TDUs argue that the treatment of state resource adequacy standards is confusing when coupled with the Regional Reliability Organization standards. The Midwest TDUs question whether section 68.1.2.a requires all market participants, including municipal utilities that are not subject to state commission jurisdiction, to adhere to state reserve requirements. For clarity and preservation of jurisdictional lines, the Midwest TDUs suggest that sections 68.1.2.a and 68.1.2.b should be altered to state that market participants need only to comply with “applicable” state standards. The Midwest TDUs are also concerned that under section 68.2.1.a.iii, if there is an

"irreconcilable difference between the reliability or resource adequacy obligations of an applicable [Regional Reliability Organization(s)] . . . and a state (or states)," the Midwest ISO may determine standards that fully comply with the obligations imposed by the states while complying only with that portion of the Regional Reliability Organization's requirements that is feasible.[222] The Midwest TDUs assert that where a load-serving entity is subject to multiple standards, the Midwest ISO should not let the utility evade Regional Reliability Organization compliance by enforcing the state's less stringent requirement.

315. Overuse and inappropriate use of the capitalized term "Load" produces a confusing tariff, especially in regards to Module E, according to the Midwest TDUs. They note that according to the definition in section 1.1.68, Load is energy that is consumed in the Transmission Provider Region which could be interpreted to mean inside of a Midwest ISO control area. However, Module E, section 68.1.1.b refers to market participants that serve Load outside of the Transmission Provider Region, and this would conflict with the as-interpreted definition. The Midwest TDUs request a Commission directive that specifies a more refined use of term "Load" to eliminate confusion.

316. Finally, the Midwest TDUs seek clarification that the Commission is not pre-judging the merits of behind-the-meter generation by referring the Midwest ISO in P 422 of the TEMT II Order, to use a recent PJM order for guidance about incorporating said resources into the Midwest ISO. They note that PJM's stakeholders are still considering the treatment of behind-the-meter resources and that Midwest ISO stakeholders should be given the same opportunity to develop their own provisions regarding these resources.

317. WPS Resources requests that the Commission clarify that the Midwest ISO and PJM are required to adopt the same resource adequacy measures prior to market-based bidding. WPS Resources states that the Commission has a "tremendous opportunity to avoid prior mistakes made during ISO formation in the Northeast" by requiring a single, permanent resource adequacy program for the Midwest ISO and PJM.[223] It states that a single resource adequacy program would eliminate future problems in the transition to a joint and common market, add to the competitiveness of what will be the largest common market in the United States, and would be less burdensome now than later because PJM is currently revising its resource adequacy program to parallel NYISO's program, and the

[222] Midwest TDUs Request for Rehearing at 54-55 (quoting Module E, section 68.2.a.iii, Original Sheet No. 815).

[223] WPS Request for Rehearing at 8.

Midwest ISO does not yet have a program in place.

318. Manitoba Hydro is concerned that Module E usurps the authority of the Regional Reliability Organizations and threatens to damage the existing resource adequacy requirements in the MAPP region. Manitoba Hydro argues that rather than relying on the pre-existing reliability mechanisms of the states within the Midwest ISO region, Module E introduces numerous new requirements that will frustrate the existing MAPP requirements and introduces new seams into the MAPP region which incorporates both Midwest ISO and non-Midwest ISO members. In particular, Manitoba Hydro states that Module E creates issues regarding section 69, Designated Network Resources (DNRs) because owners of generation resources that make capacity sales could find themselves designated as Network Resources, subject to the corresponding DNR responsibilities. They state that in the MAPP region there are a number of capacity contracts from MAPP members inside Midwest ISO to MAPP members outside of the Midwest ISO. They ask the Commission to direct the Midwest ISO to not require changes to these capacity contracts, particularly those with exports sourced at a Network Resource during a declared emergency.

iii. Discussion

319. We grant the Coalition MTC request for clarification that the Commission is not mandating a particular model of long-term RAR for the Midwest ISO. As the Commission acknowledged in the TEMT II Order, “the details of an effective RAR plan may vary by region, and as such, we will require permanent RARs that consider the unique characteristics of a market’s participants, the region’s needs and the views of applicable states.”[224] The Midwest ISO is composed of multiple NERC Reliability Regions, time zones, control areas, and states and thus there are multiple stakeholder views that undoubtedly will factor into the long-term RAR plan that will be filed with the Commission. The Commission does not want to cut off the stakeholder process that is underway and making significant progress in the Midwest. While stakeholder consensus is not essential for the Commission to approve a long-term RAR plan, due consideration of stakeholder views is appropriate, as stated in the TEMT II Order.[225] Finally, we note that although the Commission “strongly encouraged” stakeholders to seek a common

[224] TEMT II Order at P 397.

[225] “We expect that the final RAR plan will give due consideration to stakeholder views, but we also recognize that achieving uniform agreement on all aspects of such a plan may be impossible.” *Id.*

Installed Capacity market with PJM, this was not a Commission directive.[226] However, at a minimum, the long-term RAR plan that the Midwest ISO files cannot directly conflict with the PJM RAR plan.

320. PSEG states its concerns regarding the interim nature of the resource adequacy plan in Module E and requests that the Commission set a date certain when the interim plan will terminate and the permanent plan will begin. We deny this request. A directive of this nature would undercut our prior directives in the TEMT II Order for the Midwest ISO to submit a date when it proposes to file a permanent plan with the Commission.[227] Issuing a directive now also would undermine the ongoing stakeholder work on this issue.

321. We deny as premature Detroit Edison's requests for: (1) clarification about the qualifications to be designated as a Network Resource; and (2) more details on the interim plan in 30 days. We likewise deny the Midwest TDUs' request for more clarity about the validation of Network Resources. We have already directed the Midwest ISO to file additional support about the specific resources that may qualify as Network Resources within 60 days of the issuance of the TEMT II Order, and will address that filing in a future order.[228] If more details on the interim plan are needed, the Commission will issue a directive in its future order.

322. We deny Manitoba Hydro's request that the Commission direct the Midwest ISO to respect MAPP's resource adequacy program by deleting Module E in its entirety. Module E is a result of a prior Commission directive to include a resource adequacy plan with the Midwest ISO tariff filing.[229] Module E is necessary to ensure that adequate reserves are available for the regional market in the interim period until the long-term RAR plan is filed with the Commission. In any event, we do not construe Module E as authorizing noncompliance with MAPP's resource adequacy program.

323. We disagree with Manitoba Hydro's assertion that owners of generation resources may find themselves designated as Network Resources. As is noted elsewhere in this order, section 69.1 of Module E specifies that the market participants themselves will

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[226] *Id.*

[227] *Id.* at P 421 (listing Commission directives for Module E).

[228] *Id.* at P 422.

[229] *See* Declaratory Order at P 50.

identify which resources are available to meet their specific reliability requirements. Furthermore, section 69.1.2 of Module E specifies that designation of a Network Resource requires ownership or its contractual equivalent (such as providing proof that the generation owner accepts designation as a Network Resource).[230] Thus, no generation resources should suddenly and unexpectedly find themselves designated as Network Resources. Also resources that are outside the Midwest ISO region have no obligation to register with the Midwest ISO.[231] Furthermore, section 68.1.1.a states that a market participant serving load within the Midwest ISO must comply with all requirements of the appropriate Regional Reliability Organization where the market participant's load is located. This section should preserve the terms and conditions of the MAPP region's resource adequacy plan. For load that is served outside the Midwest ISO region, section 68.1.1.b states that "Module E does not impose upon the Market Participant any obligation to conform to the [Regional Reliability Organization] standards."[232] For the foregoing reasons we find that the changes requested by Manitoba Hydro are not necessary. We therefore deny Manitoba Hydro's rehearing requests.

324. We deny the request of WPS Resources that Midwest ISO and PJM have the same RAR plan in place prior to the start of market-based bidding (the Commission assumes WPS Resources means prior to market start-up). The Commission recognizes the forward-thinking view taken by WPS Resources that differing RAR plans of the Midwest ISO and PJM could lead to a trading seam. Ideally, the stakeholders in the Midwest ISO region and the PJM region will agree on a common resource adequacy and capacity payments plan going forward in recognition of the joint-and-common market goal. However, the Commission will not now mandate the adoption of a common RAR for the Midwest ISO and PJM. Such a mandate would reverse the progress already made by stakeholders and quite possibly delay the development of the permanent Midwest ISO RAR plan. The Commission has stressed and continues to believe that a RAR plan must be reflective of the views of its stakeholders, including the states and reliability regions.[233] WPS Resources is correct that there are benefits to having PJM and the Midwest ISO use the same RAR plan. WPS Resources notes that there are proceedings underway between PJM, NYISO, and ISO-NE to work toward a regional capacity and resource adequacy market. We recognize that that proceeding is under way, but note that

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[230] Module E, section 69.1.2, Original Sheet No. 820.

[231] *See* Module E, section 68.1.1.b, Original Sheet No. 811.

[232] *Id.*

[233] *See* TEMT II Order at P 397.

those markets are evolving and the implementation of a common resource adequacy market has not yet been realized.[234] While we agree that the ultimate goal of a common RAR program between the Midwest ISO and PJM is a laudable and probable outcome, we disagree that the lack of a common inter-RTO resource adequacy plan should delay market implementation, and we clarify that market start-up would have to be delayed to grant this request.

325. We grant the Midwest TDUs' requested clarifications with respect to market participants' compliance with "applicable" state standards and the treatment of behind-the-meter generation.

326. Regarding the treatment of state standards, we clarify that the Commission's conditional acceptance of Module E was not an endorsement of exercising jurisdiction over municipal parties that are not regulated by their respective state's regulatory commission and would not necessarily be subject to that state's reserve requirements. Therefore, we direct the Midwest ISO to clarify section 68.1.2.a by adding the word "applicable," so that the section reads:

> Market Participants that serve load within the Transmission Provider Region must comply with all *applicable* regulations and laws regarding reliability, including any reserve margin requirements, of the states in which the Transmission Provider operates.

327. We further direct the Midwest ISO to clarify section 68.1.2.b by adding the word "applicable" so that the section reads:

> To the extent that a Market Participant serves load in two (2) or more states in the Transmission Provider Region, the Market Participant must comply with the *applicable* reliability or resource adequacy requirements of each state in which it serves load.

328. These changes benefit all users of the tariff by clarifying which standards apply to the various classes of market participants that will be affected by Module E. However, we decline to adopt the Midwest TDU's suggested edits to sections 68.2.1.a.i.,

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[234] *See New York Independent System Operator, Inc.*, 109 FERC ¶ 61,023 (2004) (accepting compliance report entitled "Report on Status of Regional Adequacy Markets Working Group").

68.2.1.a.iii, and 68.2.1.b.ii because we accept that the Midwest ISO needs to retain some discretion in these interim measures as it determines which resource adequacy standards are applicable. We note that this does not change our conditional acceptance of section 68.2.1.a.iv (pending a decision on the Midwest ISO compliance filing), which states that if the Midwest ISO cannot determine that a reserve standard is in effect within a state then an annual 12 percent default reserve margin will be applied to load in that state.[235]

329. We clarify that our directive in paragraph 422 of the TEMT II Order regarding the procedures to qualify Alternative Capacity Resources in Module E, and in particular our guidance on behind-the-meter generation, did not prejudge the merits of the Midwest ISO's compliance filing. The reference to the PJM proceeding[236] was intended to notify stakeholders in the Midwest ISO that there was an ongoing proceeding dealing with similar issues, and given the future joint and common market, the stakeholders should monitor that proceeding and consider it while constructing their own permanent plan for Alternative Capacity Resources.

330. In conclusion, we emphasize that the current Module E is effective for the interim period and it will sunset upon Commission acceptance of a long-term RAR plan. Therefore, parties that submitted requests for rehearing in this proceeding, along with all other stakeholders in the Midwest ISO, maintain the ability to participate in the development of the final, permanent resource adequacy plan that will be submitted to the Commission and they should use that forum accordingly.

b. Applicability of Resource Adequacy Requirements

i. Background

331. Module E is intended to apply to the Midwest ISO and all market participants that serve load within the Midwest ISO region. If a market participant serves load outside the Midwest ISO region, Module E does not impose any obligation as to that load.

ii. Requests for Rehearing

332. FirstEnergy requests a Commission requirement that the resource adequacy requirements apply to all load-serving entities within the region, not just market participants. It also asserts that the current definition of applicability could be interpreted

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[235] Module E, section 68.2.1.a.iv, Original Sheet No. 816.

[236] *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,113 at P 27-33 (2004).

to mean that some load-serving entities will subsidize other non-load-serving entities that do not have to plan for resource adequacy.

333. Cinergy renews its request from its May 7, 2004 protest that section 68 of Module E be stricken in its entirety. In general, Cinergy views Module E as an unneeded plan that will delay the progress toward a permanent plan because it uses resources to determine the implementation of the interim plan and because the reserve margins in the Midwest are high. Cinergy also argues that Module E is redundant because it adds complexity to the compliance requirements by requiring load serving entities to meet different standards.

iii. Discussion

334. We deny First Energy's request that the RARs should apply to all entities that serve load in the Midwest ISO region, irresepective of whether they are or are not a market participant. The Midwest ISO explains that the requirements listed in Module E, that only a market participant that serves load in the Midwest ISO region designates Network Resources and is expected to abide by the corresponding Network Resource requirements,[237] are meant to codify the pre-existing reliability requirements in effect in the Midwest ISO region.[238] And the Commission accepted Module E, thus accepting pre-existing requirements.[239] The requirements on load-serving entities, including FirstEnergy, should not be significantly different than they were prior to Module E's implementation.

335. Moreover, that a market participant serving load within the Midwest ISO region will be required to comply with Module E, whereas a non-market participant serving load within the region will not be, is not unduly discriminatory. The decision to become a market participant is made by the utility, and thus the application of Module E also is driven by the utility's choice. Moreover, a non-market participant serving load within the Midwest ISO region is unlikely to be jurisdictional; it thus would be beyond the Commission's authority to hold them to RARs. More importantly, since such non-market participants likely would be wholesale customers of an entity that is a market participant acting on their behalf (as explained below), they are differently situated from those who are market participants.

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[237] *See* TEMT II Order at P 127 n.235 (noting the requirements of section 69.1).

[238] *See* Module E, Introduction, Original Sheet No. 810.

[239] *See* TEMT II Order at P 421.

336. In this regard, we need to make clear that a Load Serving Entity, a defined term, is not necessarily the same as an entity serving load in the Midwest ISO region. A Load Serving Entity, as defined in Module A, is "[a]ny entity that has undertaken an obligation to provide electric energy for end-use customers by statute, franchise, regulatory requirement or contract for Load located within or attached to the Transmission System."[240] However, there is an exemption for smaller entities: "Where a distribution cooperative or a municipal distribution system otherwise covered by the prior sentence is a wholesale customer of a generation and transmission cooperative or a municipal joint action agency, the generation and transmission cooperative, a state or federal agency or municipal joint action agency may act as the Load Serving Entity for such distribution cooperative or municipal distribution system."[241] A Load Serving Entity, therefore, is not necessarily an entity serving load. Thus, when the TEMT subjects *market participants* serving load – including FirstEnergy – to RAR, it is not subjecting all entities that serve load to RAR.[242] Distribution cooperatives and municipal distribution system are entities that are specifically exempt from the definition of Load Serving Entity, and thus need not be market participants (as they are customers of market participants), yet they still serve load. They would likely not be jurisdictional public utilities, and we could not apply RAR to them. It is not inappropriate, therefore, for the TEMT to exempt non-market participants serving load in the Midwest ISO region from RAR requirements. And, more importantly, the entities that are exempt from RAR requirements, because they are wholesale customers with a market participant acting on their behalf as a Load Serving Entity, are differently situated than Load Serving Entities who can act on their own behalf.

337. We deny Cinergy's request to strike section 68 in its entirety and reject its redlined changes to the section. As noted elsewhere in this order, we recognize that the Midwest ISO's Module E necessitates discretion in applying the Regional Reliability Organization and state reliability standards in effect – including resolving differences between state and Regional Reliability Organization resource adequacy requirements, and determining standards that apply in the Midwest ISO region.

[240] Module A, section 1.171, Original Sheet No. 92.

[241] *Id.*

[242] *See, e.g.*, Module E, section 68.1.1.a, Original Sheet No. 810 ("A Market Participant serving Load within the Transmission Provider Region must comply with all requirements . . . .").

338. We reject Cinergy's suggested edits to Original Sheet No. 822, to strike "at the sole discretion of the Transmission Provider" to determine the sufficiency of the System Impact Study performed during the interconnection process. We find that the Midwest ISO is uniquely positioned to determine the sufficiency of these studies and therefore it should have the discretion to determine what is sufficient for this purpose. We additionally find that Cinergy's suggested clarification has been addressed by our directive to the Midwest ISO to clarify their Network Resource qualification procedures in the TEMT II Order.[243]

339. We find that Cinergy's suggested clarification to Original Sheet No. 823, to apply any grace period for Network Resource requirements equally, is moot due to our directives in the TEMT II Order.[244]

340. We reiterate that this is an interim plan; as such, it is intended to be replaced by a long-term RAR plan that includes an installed capacity component[245] (which will thereby mitigate any potential free-rider problem as to regional versus local resource adequacy). For the interim period, though, resource adequacy will continue to be determined at a sub-regional basis based on the applicable state and Regional Reliability Organization requirements that the Midwest ISO determines are in effect.

2. The Must-Offer Requirement

a. Background

341. Module E contains a must-offer requirement that applies to designated Network Resources whereby Network Resources must submit a self-schedule or offer in the day-ahead energy market and in the first RAC process, unless the resource is unavailable due to a full or partial forced outage. The must-offer requirements are specified to reflect resource operational limitations. The Midwest ISO may also curtail exports sourced at a Network Resource or from the energy markets during a declared emergency.

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[243] *See* TEMT II Order at P 404.

[244] *Id.*

[245] *See id.* at P 411.

b. Requests for Rehearing

342. Cinergy seeks rehearing of the Commission's acceptance of the must-offer requirement contained in section 69.2 of Module E because, it argues, the Commission confused resource adequacy and operating reserves. Cinergy argues that section 69.2 appears to require a generation owner to self-schedule or offer into the day-ahead market and the RAC process all of its Designated Network Resources (DNRs). Cinergy argues that this is problematic because the day-ahead market is financial only and it is the RAC process that is used for reliability purposes; therefore the must-offer should only apply to the RAC process. Cinergy says section 68 does not make clear whether the capacity resource requirements contained there are determined on the basis of annual or six-month peaks. It asserts that since the must-offer requirement is intended to ensure that sufficient reserves are available on a daily basis there is no reason that a utility should be required to commit a substantial portion of its resources when load levels are low. Cinergy offers that each Regional Reliability Organization presently has an operating reserve margin that must be met by each load-serving entity for the next day and that any must-offer requirement should be tied to those Regional Reliability Organization reserve margins rather than to the must-offer requirement of section 69.2. Finally, Cinergy argues that applying the must-offer requirement to the day-ahead market without a corresponding capacity payment is inconsistent with Commission policy.

343. LG&E asserts that the Commission violated FPA section 201(b) by approving the TEMT, and in particular by approving the must-offer requirement for the day-ahead market and the RAC. They argue the must-offer requirement strips LG&E's authority over its integrated resources that it uses to fulfill its state obligation to serve and essentially expands federal jurisdiction over retail sales of electric energy to bundled load. LG&E reiterates its view that any changes to jurisdictional responsibilities should be conditioned on an "opt-out" arrangement whereby entities like LG&E would be permitted to not abide by sections of the tariff that they view as requiring them to operate their generation facilities under Midwest ISO and Commission mandates rather than those of the Commonwealth of Kentucky.

344. PSEG requests rehearing or clarification of the Commission's decision to grant the must-offer provision on an interim basis without a functional capacity market mechanism in place. PSEG argue that the interim must-offer requirement along with a $1,000 bid cap and automatic mitigation measures reduces opportunities to recover scarcity costs, but does not compensate for that reduction in cost recovery. PSEG also has concerns that the time frame surrounding the interim plan may delay the development of the permanent resource adequacy plan. PSEG requests that the Commission direct the Midwest ISO to remove the must-offer requirement until the resource adequacy requirement includes provisions for capacity payments. In the alternative, it requests that the Commission set a firm date for the end of the interim plan and the beginning of the permanent plan.

c. Discussion

345. We deny Cinergy's request for rehearing in favor of a revision to the must-offer requirement to require only the load-serving entity's next-day forecast load plus its operating reserve requirement to be bid into the day-ahead market. We note Cinergy's argument that the reserve requirement should be based on the Regional Reliability Organization reserve margins and not the annual or six-month peak.[246] The Commission agrees that this is the method of ensuring adequate reserves currently used in certain Regional Reliability Organizations. However, we disagree that as a result of current Regional Reliability Organization practices, changes to Module E are needed. We note that the introduction to Module E currently states that "[t]he resource adequacy requirements established in this Module E are based upon the pre-existing reliability mechanisms of the states within the Transmission Provider region and within the Regional Reliability Organizations . . . ."[247] Section 68.1.1.a states that "A Market Participant serving Load within the Transmission Provider Region must comply with all requirements, including those related to operating and planning reserves, of the appropriate [Regional Reliability Organization] governing the location(s) where the Market Participant's Load is located."[248] Therefore, we accept that the Midwest ISO will balance the existing requirements of the Regional Reliability Organizations with the new requirements of Module E and they can do this without being unduly burdensome on those market participants that possess Network Resources.

346. We deny rehearing regarding Cinergy's request to remove the must-offer requirement from the day-ahead market and instead only have it apply to the RAC process. We disagree with Cinergy's statement that "[t]he Reliability Assessment Commitment is intended to address reliability. Participation in the day-ahead market establishes a financial commitment, and is not reliability-driven."[249] The day-ahead market results in financially binding schedules that ensure day-ahead load can be reliably

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[246] Cinergy Request for Rehearing at 46.

[247] Module E, Introduction, Original Sheet No. 810.

[248] Module E, section 68.1.1.a, Original Sheet No. 810.

[249] Cinergy Request for Rehearing at 47.

met. The RAC process is used if insufficient resources are committed in the day-ahead market to meet the Midwest ISO forecast load, and to reflect changes in system conditions.[250] The day-ahead must-offer will help ensure supplies are sufficient to meet load and to avoid excessive prices from shortages and therefore we will maintain the must-offer requirements in the tariff. Furthermore, we disagree with the statement that "[t]here is no reasoned basis for making the must-offer requirement applicable in the financially-binding Day Ahead Market, and thereby foreclosing the ability to only offer the unit in the Real-Time Market."[251] Network resources may participate in the real-time market through bidding flexibility in the day-ahead market, subject to the constraints of the mitigation measures. Finally, we deny Cinergy's request for clarification on Original Sheet No. 824, which refers back to Cinergy's May 7, 2004 protest on the must-offer requirement. Except for the clarification of the must-offer granted below, we accept that the must-offer contains sufficient details and we will not direct the Midwest ISO to file additional details.

347. We deny LG&E's request for rehearing of the must-offer requirement. We do not agree that the must-offer requirement contained in Module E will strip LG&E of its authority over the integrated resources it uses to fulfill its state obligation to serve or that the must-offer requirement violates section 201(b) of the FPA and expands federal jurisdiction over retail sales of electric energy to bundled load. We disagree with LG&E's statement that a jurisdictional conflict occurs because the tariff mandates market participation by making their generation facilities available to the Midwest ISO "pool" even if the utility wishes to use their generation resources solely to serve in-state (Kentucky in this case) native load.[252] LG&E is not forced into the market to buy power from its own generators to serve native load. LG&E has the choice of self-scheduling its resources to serve its retail load in total or in part, and can rely on the Midwest ISO markets to meet all or a portion of its planned load, or to meet only real-time deviations in load. The must-offer requirement affects LG&E's resources only to the extent they are

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[250] The TEMT clearly articulates the RAC function by stating that "[t]he RAC process *assists* the Transmission Provider to reliably operate the facilities within the Transmission Provider Region by allowing the Transmission Provider to commit additional Resources beyond those selected for the Day-Ahead energy market if needed to meet the load forecast and capacity requirements." Module C, section 40.1.1, Original Sheet No. 532 (emphasis added).

[251] Cinergy Request for Rehearing at 47.

[252] LG&E Request for Rehearing at 6.

not needed for its native load. Accordingly, the Commission did not violate FPA section 201(b) by accepting the must-offer requirement.

348. We similarly believe that LG&E will be able to serve its native customers and get the maximum economic value from its generation facilities. Market participants will be able to maximize the economic value of their resource and serve their native load at least cost due to the security-constrained, least-cost dispatch framework of the day-ahead, RAC, and real-time markets. We find that there are specific economic solutions available to all load-serving entities that participate in the Midwest ISO's markets. For example, if the real-time prices are lower than LG&E's marginal cost, LG&E can purchase from the real-time market and serve its native customers at lower cost. LG&E also can make an economic choice about whether to retain or sell its excess, non-network resource capacity, at any time. In addition, FTRs will be available to cover any price differentials that may occur on historical pathways to serve native load.

349. For the same reasons and because it is an unnecessary alternative to a workable provision already present in the tariff, we deny LG&E's proposal for an "opt-out" provision for aspects of the tariff, such as the must-offer requirement. Giving utilities the option to decline to abide by portions of the tariff would undermine the ability of the Midwest ISO to ensure reliability and least cost dispatch as well as create inequities in the applications of the requirements.

350. We deny PSEG's request to remove the must-offer requirement absent a corresponding capacity payment. In the TEMT II Order, the Commission found the interim must-offer requirement to be a necessary component of the Midwest ISO's market structure and nothing presented by PSEG convinces us otherwise. In addition, we reiterate our statement from the TEMT II Order that the stakeholder process should be given the opportunity to develop major components of RAR, such as a capacity payment plan.[253] The load-serving entity and the generator may determine the appropriate payment structure for the obligation of becoming a DNR and thus the resource may receive an implicit capacity payment under the current Midwest ISO proposal.[254]

351. We grant the Midwest TDUs' request for clarity on the details of the must-offer requirement. We direct the Midwest ISO to clarify that submission of offers to comply with the must-offer requirement must comply with the offer requirements specified in Module C for the day-ahead market and RAC processes.

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[253] TEMT II Order at P 411.

[254] *See id.* at P 410.

3. Withdrawal from Reserve-Sharing Groups

a. Background

352. Section 68.1.1.d of the TEMT requires market participants that serve load in the Midwest ISO region and that are currently members of reserve-sharing groups, to obtain approval from the Midwest ISO prior to their withdrawal from such groups. In response to protests by Ameren and MAPP, in the TEMT II Order the Commission required the Midwest ISO to explain the terms of its agreement with MAPP, which recognizes the Midwest ISO as Reliability Authority.[255]

b. Requests for Rehearing

353. Exelon notes that the Commission conditionally accepted Module E in the TEMT II Order. Exelon requests clarification that, given the Commission's requirement that the Midwest ISO explain the source of its authority to impose the requirements of TEMT section 68.1.1.d, the Commission has not accepted that section. Exelon seeks to preserve its right to challenge the authority of the Midwest ISO to impose such a requirement once the Midwest ISO makes its compliance filing. It also seeks clarification that any opposition to the Midwest ISO's filing can extend to the question of whether such a requirement is related to reliability and whether such a requirement violates existing voluntary agreements. In the alternative, Exelon requests rehearing of the Commission's statements that the Midwest ISO's need to maintain system reliability extends to voluntary relationships by control areas to share operating reserves.

354. Exelon states that control areas are responsible for maintaining sufficient operating reserves and that it is aware of no requirement that makes participation in reserve sharing groups mandatory. Citing Mid-America Interconnected Network provisions, it avers that the terms of withdrawal from reserve sharing groups are provided for in agreements between control areas. Exelon therefore contends that reserve sharing withdrawal is not a reliability issue since control areas would be left with the responsibility of carrying additional operating reserves if market participants withdrew from reserve sharing arrangements.

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[255] *Id.* at P 420.

355. First Energy requests that the Commission clarify the intent of paragraph 420 from the TEMT II Order.[256] Specifically, it requests that the Commission clarify the statement directing the Midwest ISO to "explain the source of its authority to impose this requirement." First Energy was unclear what "this requirement" was referring to in paragraph 420. If it means a broad mandate to establish resource adequacy requirements, then First Energy requests that the Commission reverse that determination. If it applies specifically to withdrawals from reserve sharing agreements, then First Energy requests that the Commission clarify that states have the lead role in the establishment of reserve levels and the role of the Midwest ISO is to act as a monitor.

356. Cinergy renews the portion of its protest from May 7, 2004, that asks for clarification that the Midwest ISO should not have review and approval rights on reserve sharing groups.

c. Discussion

357. We clarify that the Commission's approval of section 68.1.1.d is conditional pending the Midwest ISO adequately complying with our directive to explain the source of its authority to require its prior approval before market participants may withdraw from reserve sharing groups.[257] We further clarify that in the compliance filing proceeding parties can challenge the impact of the reserve-sharing provisions on reliability and contractual arrangements. We also direct that this compliance filing address Cinergy's request for clarification from their May 7, 2004 protest and suggestions for Original Sheet No. 811.

358. We grant First Energy's and Exelon's request for clarification regarding paragraph 420 of the TEMT II Order. Paragraph 420 was meant to specifically apply to the Midwest ISO's authority to impose a prior-approval requirement for market participants that want to withdraw from reserve sharing groups. It was not meant to imply that the Midwest ISO has the sole authority over resource adequacy in the region at the exclusion of the states' rights. In fact, elsewhere in the TEMT II Order the Commission directed the Midwest ISO to consider the views of the applicable states as well as the needs of the region.[258] However, we disagree with First Energy's assessment of the Midwest ISO's

[256] *See id.* at P 131.

[257] *See id.* at P 420. When the Commission reviews the Midwest ISO's October 5 Compliance Filing and any comments thereto about withdrawal from reserve sharing groups, the Commission's approval of this provision could be overturned.

[258] *Id.* at P 397.

role as a “monitor” only. Ultimately, when a long-term RAR plan is filed with the Commission, it will be the product of numerous stakeholder discussions, but the Midwest ISO will be the party filing and administering the RAR plan.

I. Credit Policy

1. General Proposal

a. Background

359. The Midwest ISO lists its credit policy in Attachment L. The credit policy is applicable to all market participants engaged in all types of market activity. Accordingly, Attachment L contains requirements that specify the establishment of credit agreements, unsecured credit limits, total potential exposure calculations, and the total credit limit for a market participant. Market participants that violate these requirements by failing to cure credit violations within two business days may have their access to credit limited and their accounts placed in default. The total potential exposure calculation refers to the cumulative financial obligation that a market participant has incurred engaging in market activities. If a market participant exceeds 90 percent of its total credit limit, the participant will be notified in writing. If a market participant equals or exceeds its total credit limit, the participant is directed to pay invoices to reduce its credit exposure and/or post additional financial security to raise its total credit limit. The total credit limit is the sum of the unsecured credit allowance and the amount of financial security provided by a cash deposit or irrevocable letter of credit.

360. In the TEMT II order, the Commission conditionally accepted the Midwest ISO’s credit policy and directed them to adopt a two-day collateral window, clarify various aspects, refile the Table 1 matrix used to determine the unsecured credit grant, and adopt an unsecured credit floor similar to that used in the NYISO markets.

b. Requests for Rehearing

361. Joint Cooperatives argue that the Commission accepted credit provisions that are unjust, unreasonable, and unduly discriminatory that could result in market participants that are cooperatives not being granted adequate unsecured credit. Furthermore, they argue that the Commission made cooperatives worse off by directing the Midwest ISO to file a Table 1 matrix similar to PJM’s which relies heavily on tangible net worth. The Joint Cooperatives renew their protest of the Midwest ISO requirement for market participants that are in arrears to provide additional financial security within two days or face default. They also request a Commission directive to the Midwest ISO to remove language in section 7.8 that would allow the Midwest ISO to suspend any pending market activities upon the occurrence of a default.

362. LG&E seeks rehearing, arguing that the credit policies in the TEMT are unjust and unreasonable. LG&E argue that the credit provisions socialize the market's credit risk and force load-serving entities to subsidize other market participants such as marketers, and make load-serving entities the credit providers of last resort. They assert that any uplift resulting from defaults should be limited to suppliers in the form of reduced payments. The Commission should clarify circumstances where the Commission rejects a Midwest ISO request to terminate service for defaulting entities. They also seek clarification of how a defaulting load-serving entity, with a state-imposed obligation to serve, would cover its load obligations. Finally, LG&E argue that the Commission relied too heavily on the credit policies of PJM and other ISOs without analyzing the impacts of those policies on the unique Midwest market.

363. AMP-Ohio requests that political subdivisions should be able to request a two-day extension of the requirement in Attachment L,[259] section II (F) to provide additional financial security within two days when a market participant's Total Potential Exposure exceeds its Total Credit Limit because they argue that otherwise they will not be able to respond quickly enough due to the political process that is often required to provide a letter of credit or extra cash.

c. Discussion

364. We deny LG&E's request for rehearing. We find the credit policies proposed by the Midwest ISO to be just and reasonable. We disagree with LG&E's arguments that the credit provisions exacerbate the risks associated with market participation and that they force load-serving entities to subsidize the credit of market participants like power marketers. To the contrary, we find that the credit policies proposed by the Midwest ISO will reasonably limit the financial risks associated with market participation through the use of cross-default provisions, weekly billing cycles, and limited unsecured credit grants which are lower than those of the other RTOs and ISOs.[260] In many respects the Midwest ISO's general credit provisions are substantially similar to other RTO/ISO credit provisions, which the Commission has accepted and have a history of successful operation. We disagree with LG&E's assertion that the Commission unduly relied on PJM and NYISO credit policies. Although the Commission noted that the Midwest ISO

[259] AMP-Ohio's request states Module C, section II (F), but the Commission assumes that AMP-Ohio means Attachment L.

[260] In comparison PJM limits its unsecured credit allowance to $150 million, and ISO-NE limits its allowance to $75 million, whereas the Midwest ISO has a maximum $50 million unsecured credit grant.

has "no legacy of centralized power pool dispatch," we find it reasonable to look to regions that do have such a history as a general indicator of workable credit policies because the Midwest ISO will have centralized dispatch going forward from March 1, 2005.[261] Finally, we note that there is a history of evolution in the other RTO/ISO markets, particularly in areas of credit policy, and that our prior conditional tariff approval on August 6, 2004, did not end the stakeholder process or the Midwest ISO's ability to make future filings to refine and revise the credit policy as the market gains operational experience.

365. We deny Joint Cooperatives' request for rehearing of the Commission's directive to the Midwest ISO to refile their Table 1 with a matrix similar to that of PJM and an unsecured credit floor similar to NYISO.[262] We note that the Commission did not direct the Midwest ISO to file a Table 1 identical to PJM's or NYISO's, only that the Midwest ISO "thoroughly justify any differences."[263] We clarify, however, that the intent of the decision in the TEMT II Order was not to exclude the participation of the cooperatives in the Midwest ISO. We also clarify that the use of the term "public power participants" was intended to include both municipals and cooperatives.[264] Finally, the appropriate place to analyze these issues and determine whether the Midwest ISO has implemented our directives is in the Table 1 compliance filing.

366. We grant clarification requested by the Joint Cooperatives that the directive contained in paragraph 478 of the TEMT II Order was meant to instruct the Midwest ISO to remove language in section 7.8 of Module A authorizing the Midwest ISO to suspend any pending market activities prior to Commission approval.[265] Section 7.4 does not reference pending market activities so there is no language to remove other than that which refers to annulments of eligible confirmed reservations of the transmission customer.[266]

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[261] TEMT II Order at P 58.

[262] *Id.* at P 437.

[263] *Id.*

[264] *Id.* at P 439.

[265] *See* Module A, section 7.8, Original Sheet No. 169.

[266] *See* Module A, section 7.4, Original Sheet No. 160.

367. We deny Joint Cooperatives' request for rehearing of the requirement in Attachment L under the ongoing credit evaluation, to post additional financial security within two business days because we find that Attachment L already contains sufficient language to assure that cooperative participants are treated fairly with regard to the initial and ongoing credit evaluations. Attachment L specifies that in completing its ongoing credit evaluation, the Transmission Provider will perform follow-up credit evaluations at least annually. It also specifies that each participant will notify the Midwest ISO of any material change in its financial condition within 5 business days of the occurrence.[267] Therefore the timeline for posting additional financial security is longer than two business days because the market participant informs the Midwest ISO of a negative material change within 5 days of the change occurring, then the Midwest ISO must respond by notifying the participant in writing, and then finally the market participant will have 2 or 3 business days depending on the time of notification before additional financial security is required. We find that it is reasonable to assume that any market participant (including municipals and cooperatives) will have adequate opportunity to consult with their respective political bodies for additional financial security during this time period. Finally, we note that in its credit evaluation of cooperatives, government agencies, and municipalities, the Midwest ISO will consider other relevant factors in determining financial strength and creditworthiness.[268] We clarify that we interpret this to mean information such as the length of generation and transmission cooperative contracts with their respective members would be used in the credit evaluations.

368. We deny AMP-Ohio's request for rehearing regarding the requirement to post additional financial security within two business days when the market participant exceeds its Total Credit Limit. Similar to our reasoning regarding the initial and ongoing credit evaluations, we find that there is adequate time to gather additional financial security in place in the Attachment L requirements as written. We note that according to Attachment L, section II (E), market participants are notified in writing when their Total Potential Exposure has equaled or exceeded 90 percent of their Total Credit Limit. We find that a properly calculated Total Credit Limit, known in advance, coupled with early written notification, is sufficient time to begin making arrangements for additional financial security, prior to actually exceeding the Total Credit Limit. Finally, we note

[267] Attachment L, Original Sheet Nos. 1216-17.

[268] Attachment L, Original Sheets Nos. 1210 and 1216 contain identical language that refers to both the initial and ongoing credit evaluations.

that the Table 1 matrix is not yet finalized nor Commission approved, but if the Table 1 is functioning properly, market participants should have a reasonable assurance that they can conduct their normal market activities without fear of exceeding their Total Credit Limit.

2. Defaults and Billing

a. Background

369. The provisions for defaults are contained in section 7 of Module A (entitled Billing and Payment). If a Transmission Customer has not paid all charges when its payment is due, the customer may enter default, according to section 7.13, and the Midwest ISO will pursue remedies to collect all past due amounts from the Transmission Customer through section 7.4 and 7.8. Once the customer is in default, the Midwest ISO will initiate a filing with the Commission to terminate the Transmission Customer's service agreement. Termination of service will not occur until the Commission approves such a request.

370. If a market participant does not pay charges associated with section 7.6 when due, the participant may enter default, according to section 7.13, and the Midwest ISO may use various remedies to collect the past due amounts. Under the procedures listed in section 7.8, the Midwest ISO will first use monies it has received to pay itself; then, after exercising their rights of set-off and recoupment pursuant to sections 7.12 and 7.15, the Midwest ISO will use funds obtained under the Credit Support Documents to the extent necessary to pay off all charges past due and interest charges. The procedures listing defaults are outlined in section 7.13. In general, a default is failure to pay any amount under sections 7.1 or 7.2 before the tenth business day after the customer receives written notice from the Midwest ISO or the ITC to cure such failure. For market participant activities under section 7.6, a default constitutes failure to pay any amount due within the second business day after the Tariff Customer receives notification from the Midwest ISO to cure such failure. In addition, a default occurs should a tariff customer enter bankruptcy proceedings. Any default with respect to a Tariff Customer is a default under the TEMT, including all provisions in Attachment L, and other agreements to which the Tariff Customer and the Midwest ISO are both parties.

371. Remedies to defaults are listed in section 7.14. If a default occurs and is ongoing, the Midwest ISO has numerous remedies it may exercise, including: (1) those under sections 7.4 and 7.8; (2) suspension of a market participant's access to submit bids or offers for FTRs; (3) suspension of a Tariff Customer's participation in any other services under the tariff, subject to Commission approval; (4) termination of services and/or agreements, subject to Commission approval; (5) termination and settlement of all FTRs in accordance with section 7.16; (6) liquidation of financial security; and (7) any and all

other remedies available and applicable under law.

372. In the TEMT II Order, the Commission accepted the Midwest ISO proposal to allow for cross-defaults. A cross-default treats a default in one category of activity or agreements as a default in all categories of activity so that market participants may not default in one area and then continue to operate in another area. The Commission directed the Midwest ISO to revise the definition of default to include a reference to section 7.13 and list the default timelines for transmission customers and market participants.

b. Requests for Rehearing

373. The Midwest ISO TOs argue that the Commission should limit the authority of the Midwest ISO to declare a market participant in default, clarify the agreements in default, and clarify that Commission approval is necessary prior to termination of FTRs. The Midwest ISO TOs argue that section 7.13.c is too expansive because it allows the Midwest ISO to declare market participants in default for failure to make any payment or comply with any requirements under the tariff and any agreements where the tariff customer and the Midwest ISO are both parties. Section 7.14 lists as available remedies for defaults: the suspension of market participant's access to submit bids/offers in the FTR auctions and termination of all FTRs held by the defaulting tariff customer. The Midwest ISO TOs argue that the Midwest ISO should have to gain Commission approval prior to taking any action to restrict a market participant's access regarding the submission of FTR bids/offers or termination of FTRs. The Midwest ISO TOs seek Commission clarification of the TEMT II Order's acceptance of the cross-default provisions contained in section 7.13.d that specify that any default with respect to the tariff, constitutes a default in any and all other agreements entered into where the tariff customer and the transmission provider are both parties. The Midwest ISO TOs argue that this section is too broad because it could encompass any agreement, including existing settlement agreements, and therefore they request that the Commission on rehearing order the Midwest ISO to modify the TEMT to clarify the scope of agreements to which this cross-default provision would apply.

374. The Midwest SATCs ask the Commission to grant rehearing on their request to have the Midwest ISO distinguish in its credit policies between transmission and energy market transactions to determine set-off and netting rights in customer bankruptcy proceedings, and in calculating the collateral requirements. The Midwest SATCs fear that the current credit policy could lead to cross-service indemnification because it does not retain distinctions in service when accounting for the collateral requirement. The Midwest SATCs claim that the Midwest ISO could claim a priority interest in transmission revenue collected from a defaulted customer to keep itself whole, at the expense of the party entitled to the revenue.

375. AMP-Ohio requests revisions to the definition of default contained in section 7.13.c, the default cure period, the default notification method in section 7.15, and limits to the recovery of costs associated with uplifts to those that are reasonable in section 7.14.d. AMP-Ohio also protests the indemnification provision contained in section 10.2 and Attachment W.

376. AMP-Ohio renews its request that the two-day default cure period contained in section 7.13 be extended to five business days for municipalities because it asserts that they, as political entities, are not always able to respond quickly and are not true credit risks. In section 7.15, it requests that the first-class mail option be removed as an option to notify participants of defaults.

377. AMP-Ohio renews its request from its May 7, 2004 protest to expand the definition of default contained in section 1.62 in which default is defined as a failure to include payment as described in sections 7.4 and 7.8 of the tariff. AMP-Ohio argues that this definition is too limited because it does not refer to all possible defaults listed in section 7.13.c, including any agreements entered into between the tariff customer and the transmission provider.

c. Discussion

378. We deny AMP-Ohio's request for revision to section 7.14.d regarding "reasonable" recovery costs as moot because the Commission already ordered the requested remedy in the TEMT II Order.[269]

379. We deny AMP-Ohio's request to extend the default cure period from two days to five. According to section 7.6, market participants have to pay their invoices within seven days of receipt. If market participants do not pay within the initial seven days, they have two business days after they receive notification from the Midwest ISO to cure the initial failure to pay, before a default has occurred. AMP-Ohio has not demonstrated that it will not be able to pay its invoices for market activities within 9 days of when they receive their invoices. Furthermore we note that to lessen the amount of financial security needed to participate in the markets, the Commission directed that the Midwest ISO net market activities across market categories for all participants and that the Midwest ISO remove the grant of a first-priority security interest requirement.[270]

[269] TEMT II Order at P 479.

[270] *Id.* at P 450.

380. We grant a limited clarification of AMP-Ohio's request to modify the methods of notice in section 7.15. We agree with AMP-Ohio that first class mail should not be an option for notification of default because it does not provide a means of verification that notice has been served. We direct the Midwest ISO to remove first class mail as an option from section 7.15.d.

381. We deny AMP-Ohio's request to expand the definition of default contained in section 1.62 as moot. In the TEMT II Order, the Commission agreed that the limited definition of default in section 1.62 did not sufficiently contain all possible instances of default, and we directed the Midwest ISO to revise the definition of default to include a reference to section 7.13 for the list of all default conditions.[271]

382. We grant the Midwest TOs' request for clarifications relating to the scope of defaults in sections 7.13.c and 7.13.d and to the available remedies for defaults in section 7.14. Therefore, the Commission directs the Midwest ISO to clarify the scope of agreements covered by the language in section 7.13.c that states that a default will occur where the tariff customer fails "to make, when due, any payment or comply with or perform any agreement, obligation or requirement under this Tariff…" and in section 7.13.d, "any and all agreements entered into by such Tariff Customer under, pursuant to, or in connection with, this Tariff and any and all other agreements to which such Tariff Customer and the Transmission Provider are parties."[272] We direct the Midwest ISO to specifically answer whether an existing, Commission-approved, settlement agreement could be declared in default. The Midwest ISO must clarify what, if any, agreements it intends to exclude from the requirements of section 7.13.

383. In the TEMT II Order, the Commission required prior approval before any suspensions of pending market activities and annulments of confirmed transmission reservations could become effective after the occurrence of a default.[273] The Commission also ordered the Midwest ISO to remove language from section 7.14.a stating, "subject to the receipt of any approval from the Commission that may be necessary" and replace it with language stating, "subject to the receipt of approval from the Commission" or identify areas where the Midwest ISO would argue that it is appropriate to terminate service without prior Commission approval.[274] We clarify and direct that

[271] *See id.* at P 476.

[272] Module A, section 7.13.c - .d, Original Sheet Nos. 181, 184.

[273] TEMT II Order at P 478.

[274] *Id.* at P 477.

sections 7.14.a.ii and section 7.14.a.vi be revised to add that Commission approval is required prior to suspension of a market participant's access to submit FTR auction bids and/or offers and prior to termination and settlement of any and all FTRs held by the tariff customer. This is consistent with our decision to require Commission prior-approval for any terminations of service and it is reasonable because the Midwest ISO should not be able to terminate FTRs, prior to a Commission decision on termination of service.

384. We deny the Midwest SATCs' request for rehearing of the netting and set-off rights in the event of a customer bankruptcy. We find it is just and reasonable for the Midwest ISO to use revenue collected from customers to offset their default in another category of market service. This is consistent with our prior approval of the Midwest ISO's cross default procedures.[275] We disagree with the Midwest SATCs' assertion that the billing procedures are inappropriate because the Midwest ISO gives itself a better chance to remain financially whole, at the expense of the entity that would be otherwise entitled to the revenue. The Midwest ISO will retain its administrative costs and then pass-through any collected funds to the transmission owner and/or ITC *pro rata* in the order of the creation of the debts according to provisions stated separately for transmission customer defaults.[276] Also, there are separate funds distribution procedures listed for market participant's defaults relating to transactions under Module C of the tariff presently in the billing procedures.[277] It is appropriate for the Midwest ISO, as the non-profit, independent operator of the grid, to make distinctions between transmission and energy market service in their billing procedures and then distribute the funds acquired in connection with defaults and past due amounts.

385. We likewise deny the Midwest SATCs' request for rehearing to divide the collateral accounting requirements between transmission and energy market services. We find that calculating transmission related collateral separate from energy market collateral would add to the administrative costs of the RTO without a demonstrated need at this time. This would also counter the Commission's prior conditional directive to the Midwest ISO to allow netting within and across all categories of market activities to lessen the collateral burden and add to market liquidity.[278] As part of an organized

[275] *Id.* at P 476.

[276] *See* Module A, section 7.4, Original Sheet Nos. 160-64.

[277] *See* Module A, section 7.8, Original Sheet Nos. 169-72.

[278] TEMT II Order at P 446, 450.

market administered by an independent non-profit entity, the market's participants in effect, collectively extend credit to the other participants, provided that they meet the creditworthiness requirements, and consequently the market's participants collectively share the potential risk of defaults through bankruptcy for both transmission and energy market activities. The Midwest SATCs acknowledge in their comments that defaults are possible for both energy and transmission transactions and that, accordingly, the cross-default policy can result in revenue flowing in either direction.[279] However, we reiterate that the stakeholder process is an available option to shape a credit policy that is reflective of the general needs of the participants and that the Midwest SATCs may take up these issues through the appropriate task force. As noted elsewhere in this order, credit policies have not been static in other markets and we expect that there will be some evolution in the Midwest ISO as well.

3. Uplift of Uncollectible Default Amounts

a. Background

386. The Commission accepted the Midwest ISO's proposal to uplift amounts in default to other market participants based on their relative share of the absolute value of all charges and credits associated with invoices for market activities. The Commission stated that market participants need certainty of payment or the market could suffer from illiquidity and market participants could face higher energy prices as entities incorporate risk of non-payment into their bids, withhold participation in the markets or avoid the markets altogether. The Commission required the Midwest ISO to make certain modifications to explain the process the Midwest ISO will ordinarily take before implementing the uplift charge and the process for curing a default. The Commission also required the Midwest ISO to incorporate a requirement to mitigate the impact of the default amount on non-defaulting market participants.

b. Request for Rehearing

387. AMP-Ohio objects to the default provision to the extent that it provides for the uplift of defaults incurred in the spot market to parties engaged in self-scheduling and bilateral schedules. LG&E argues that the uplift provisions socialize the market's credit risk and force load-serving entities to subsidize entities such as marketers; make load-serving entities credit providers of last resort; should be limited to suppliers in the form

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[279] "The reverse is also possible, however, whereby revenue collected from energy market transactions would be used to offset transmission-related defaults." Midwest SATCs Request for Rehearing at 3.

of reduced payments, as these suppliers are best suited to mitigate or avoid credit risk; and do not address the circumstances in which the Commission rejects the Midwest ISO's request that a defaulting entity be terminated from market participation. Cinergy also states that it is impossible to determine the percentage of loss according to the formula.

c. Discussion

388. With respect to AMP-Ohio's concern, the Commission explained in a recent order on Schedule 17 that entities that engage in self-scheduling and bilateral transactions should pay the Schedule 17 charge because these entities benefit from the Midwest ISO's markets.[280] The markets increase the reliability and efficiency of the transmission grid, which even benefits entities that do not conduct spot market transactions. These markets also provide price transparency to market participants that can facilitate bilateral transactions. The Commission also explained that these entities benefit from having a market, whether or not they are engaged in spot market transactions in a given hour, and should pay the costs of establishing the markets. Therefore, all parties, including those that engage in self-scheduling and bilateral transactions, benefit from the market and should pay a share of the costs associated with the market. These costs include credit risk associated with all buyers and sellers in the Midwest ISO markets.

389. Further, the Commission explained in the TEMT II Order that sellers need certainty of being paid or else the market could suffer from illiquidity, resulting in buyers possibly facing higher energy prices as entities incorporate the risk of not getting paid into their bids, withhold participation in the markets or avoid the markets altogether. In other words, without the certainty of sellers getting paid, the markets may not function as effectively as they otherwise would, thereby reducing the benefits received by all market participants, including entities engaged in self-scheduling and bilateral transactions. For example, if the markets suffer from illiquidity and higher prices, then a bilateral transaction relying on the spot market's price transparency to set its price could also face higher prices. In addition, self-scheduling entities might face higher congestion costs as sellers withhold participation and avoid the markets due to any payment uncertainties.[281] Since self-scheduling entities and bilateral transactions benefit from the Midwest ISO's

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[280] *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,235 (2004).

[281] As market participants withhold participation and avoid the markets, the generating units, dispatched to alleviate any congestion, are likely to be more expensive generation units.

proposal to create markets that are as liquid as possible, the Commission finds that AMP-Ohio has not adequately supported its opposition to the default uplift charge.

390. We find that the default uplift should be spread footprint-wide because market liquidity, enhanced by the marketers' participation in the markets, benefits everyone through out the footprint.[282] Moreover, localized uplift of default amounts associated with marketers would be difficult since marketers can participate everywhere in the region. Further, localized uplift of default amounts associated with load-serving entities makes little sense since the defaulting load-serving entity would be unable to pay the uplift just as it is unable to pay the default amount.

391. LG&E's concern regarding when to terminate service to a defaulting customer is not yet ripe because the Commission is not taking such action in this proceeding.[283] If LG&E's hypothetical situation were to happen, LG&E may file a complaint with the Commission presenting the facts of that case and requesting review of the Midwest ISO's credit provisions.

392. Lastly, contrary to LG&E's contention, suppliers are not best suited to mitigate credit risk because suppliers may not even know the identity of the purchaser of their power, let alone their credit risk profile. Thus, we believe the Midwest ISO should perform a credit risk analysis for all market participants. Further, we note that suppliers will also pay a share of the footprint-wide default uplift; load-serving entities are not the credit providers of last resort. Rather, all market participants ensure through the uplift that the Midwest ISO, a non-profit company, has the resources to pay its bills.

[282] In the TEMT II Order, the Commission stated that it shared Cinergy's concern and required Midwest ISO to address the deficiencies in its formula rate. TEMT II Order at P 490 n.285.

[283] We note that the Commission has required the Midwest ISO to incorporate into the TEMT a provision that a defaulting customer must take all possible measures to mitigate the uplift to other parties to the maximum extent possible, including but not limited to using its own generation to supply its own load.

J. Other Tariff Issues

1. Miscellaneous Module A Issues

a. Requests for Changes to Definitions

393. AMP-Ohio requests clarification that the Affiliate definition in section 1.5 does not include AMP-Ohio members that have a membership in or participate in certain joint ventures among AMP-Ohio members as Affiliates. We clarify for AMP-Ohio that the determination of whether its affiliate designations are in compliance with the Commission's Standards of Conduct is based on the requirements of 18 CFR § 37, Subpart 358 and that the Commission is the forum for determining compliance. Order No. 2004, *et al.*,[284] provide the appropriate procedures for these determinations. Therefore, inasmuch as AMP-Ohio's issues must be addressed in other proceedings and this rehearing order is not the appropriate proceeding to resolve AMP-Ohio's concerns, its rehearing request is dismissed.

394. Cinergy raises the definition of "Business Day" on rehearing, as the Commission did not address it in the TEMT II Order.[285] In particular, the TEMT section 1.27 defines Business Day as a day in which the Federal Reserve System is open for business. This definition is then applied in the definition of On Peak, which is the "[p]eriod of time between 0600 hours EST and 2200 hours EST on Business Days." "On-Peak" is used to define the types of FTRs. A problem arises because the Federal Reserve System and the NERC System have different holiday schedules. Thus, Cinergy says, the use of the Federal Reserve holiday schedule in the context of "On-Peak" is inconsistent with the

[284] *Standards of Conduct for Transmission Providers*, Order No. 2004, 68 Fed. Reg. 30,816 (Dec. 11, 2003), FERC Stats. & Regs. ¶ 31,155 (2003), *order on reh'g* Order No. 2004-A, 69 Fed. Reg. 23,562 (Apr. 29, 2004), FERC Stats. & Regs. ¶ 31,161 (2004), *order on reh'g* Order No. 2004-B, 69 Fed. Reg. 48,371 (Aug. 10, 2004), FERC Stats. & Regs. ¶ 31,166 (2004), *reh'g pending*.

[285] Cinergy sought rehearing on its red-line tariff changes that the Commission did not consider in the TEMT II Order. *See* Cinergy Request for Rehearing at 61. One of these changes referred to the definition of Business Day. *See* Cinergy Protest at 74 (May 7, 2004)).

established use of the NERC system in commodity markets for energy (e.g., Into Cinergy), and it creates an unnecessary seam between the over-the-counter products and the FTR financial hedges to congestion. Cinergy believes that the appropriate definition of “On-Peak” is:

> 0600 -2200 EST, Monday through Friday excepting New Year’s, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day and Christmas Day or if the holiday occurs on Sunday, the Monday immediately following the holiday.

395. Cinergy says that section 43.3 should also be corrected. It provides its own definition of “On-Peak” and “Off-Peak”, referring to NERC holidays rather than those used in the definition of business day. To avoid confusion, Cinergy believes that the re-definition of On-Peak and Of-Peak in section 43.3.c should be struck, and the change recommended by Cinergy should be made to the definition of On-Peak to ensure uniform use throughout the tariff.

396. We agree with Cinergy that the business day definition of the Federal Reserve System, cited in the Midwest ISO Business Day definition, and the NERC System holidays are different, and therefore create a seam between FTR hedges and commodity markets. We also note that Cinergy’s proposed definition is consistent with the PJM definition of on- and off-peak. Accordingly, we direct the Midwest ISO to replace the current definition of On-Peak with the Cinergy proposal. We also agree that the definitions of On-Peak and Off-Peak in section 43.3 refers to NERC holidays, and therefore is inconsistent with the Business Day Definition used in other parts of the tariff. Therefore, we direct the Midwest ISO to delete the re-definition of On-Peak and Off-Peak in section 43.3.

397. Cinergy next states that section 1.41 needs to be revised to indicate that the Control Area is only responsible for actual interchange with other Control Areas and the Midwest ISO is responsible for scheduled interchange. We note that the issue of the allocation of responsibilities between control areas and the Midwest ISO is the subject of a settlement report submitted by the Midwest ISO on October 5, 2004. We will address how this provision should be revised based on the settlement that is filed and our final order on the settlement. We will therefore dismiss the rehearing on this issue.

398. Section 1.42 defines a Control Area Operator as a company’s division, personnel or affiliate that is designated as the entity with responsibility for operating a Control Area consistent with NERC policies and procedures, and the Transmission Provider’s policies and procedures. Cinergy requests the Midwest ISO to clarify and identify in the tariff the meaning of “Transmission Provider’s policies and procedures.” We agree that this

phrase is broad and subject to varying interpretations. Therefore, we direct the Midwest ISO to define more specifically the procedures and policies that Control Area Operators must follow.

399. Manitoba Hydro contends the definition of a Bilateral Transaction Schedule does not provide for a single party Offer or Bid into the market, whereas the definition of a Dispatchable External Bilateral Transaction Schedule, which is a type of Bilateral Transaction Schedule, does provide for a single party Offer or Bid into the market, and therefore the definitions are in conflict. Bilateral Transaction Schedules, by the definition of section 1.21, are a set of values representing equal withdrawals and injections at specified locations. By making a transaction dispatchable, by the terms of section 1.73, a market participant indicates an ability to respond by increasing or decreasing Resource output pursuant to Dispatch Instructions. Based on these definitions, it appears that the Midwest ISO is distinguishing between schedules that are developed for planning purposes and dispatchable transactions that have bids or offers that the dispatcher will act on to complete the transactions and therefore these definitions may not necessarily be in conflict with each other. We direct the Midwest ISO to clarify the purpose of these definitions and to revise them if there are conflicts.

400. AMP-Ohio states that the definition of Good Utility Practice should be revised to include compliance with NERC or Regional Reliability Organization standards, consistent with Commission precedent in Docket No. PL04-5.[286] We agree with AMP-Ohio that our *Policy Statement on Matters Related to Bulk Power System Reliability* clarified that Good Utility Practice, as that term is used in the Commission's *pro forma* OATT, includes compliance with NERC reliability standards or more stringent regional reliability council standards.[287] Moreover, the policy statement reiterated that RTOs and ISOs must comply with NERC reliability standards pursuant to both Order No. 888 and Order No. 2000.[288] We therefore find that it is not necessary for the Midwest ISO to revise the definition of Good Utility Practice in the TEMT to incorporate compliance with NERC and Regional Reliability Organization standards.

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[286] See Policy Statement On Matters Related to Bulk Power System Reliability, 107 FERC ¶ 61,052 (2004).

[287] *Id.* at P 23-24.

[288] *Id.* Further, Order No. 888-A, in discussing the characteristics and functions of ISOs, states that ISOs should comply with "applicable standards set by NERC and the regional reliability council." Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,247-48 (1997).

401. Cinergy proposes that a definition for Dynamic Scheduling be added to Module A, as follows: Bilateral Transaction Schedules for which the Market Participant has put in place real time and interval metering facilities approved by the Transmission Provider where Resources are supplying Energy to Load on a real time basis. We direct the Midwest ISO to comment on this proposal in its compliance filing.

402. Midwest TDUs assert that deducting the net Inadvertent Energy account from marginal losses, as required in the definition of Marginal Losses Surplus,[289] would result in double accounting and improperly reduce flowback of excess collections on marginal losses. They also state that the term "Inadvertent Energy Revenue" is no longer defined in the tariff and that the term used in section 40.7.2 is "Inadvertent Energy Value." We note that the TEMT II Order rejected the Midwest ISO's Inadvertent Energy proposal in section 40.7, without prejudice to the filing of a new proposal.[290] Therefore, this provision will have no meaning until a new definition of inadvertent energy is developed and proposed. Accordingly, we direct the Midwest ISO to revise this definition when it resubmits its inadvertent energy proposal and we will rule on the revised definition at that time. For this reason, we dismiss the rehearing request.

403. AMP-Ohio restates its protest that the definitions of Distribution Facilities[291] and Wholesale Distribution Service[292] are ambiguous since the definition of Distribution Facilities includes Market Participants whereas Wholesale Distribution Service makes no reference to Market Participants. AMP-Ohio states this ambiguity could be interpreted as granting the Midwest ISO the right to sell service over non-jurisdictional distribution facilities. In the TEMT II Order, we directed the Midwest ISO to revise the definition of

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[289] The definition of Marginal Losses Surplus is the sum of the Day-Ahead Hourly Marginal Losses Surplus and the Real-Time Hourly Marginal Losses Surplus minus the Inadvertent Energy Revenue summed across all Control Areas.

[290] *See* TEMT II Order at P 597-598.

[291] Distribution Facilities are defined in section 1.75 as facilities owned or controlled by a Transmission Owner, ITC, Market Participant or ITC Participant and used to provide Wholesale Distribution Service.

[292] Wholesale Distribution Service is defined in section 1.343 as the provision of wholesale distribution service over a Transmission Owner's, ITC's or ITC Participant's Distribution Facilities necessary to effectuate a transaction under this Tariff. To the extent such service is required, it shall be specified in the Service Agreement for the associated service being provided under the Tariff.

Distribution Facilities[293] to reflect our jurisdiction over low-voltage transmission facilities to the extent they are used to transmit electric energy in interstate commerce on behalf of a wholesale purchaser pursuant to a Commission-filed OATT, and the low-voltage transmission facilities in question are "owned, controlled, or operated by the Transmission Provider or the Transmission Owner, or both, [and] are used to provide transmission service" under the Midwest ISO OATT.[294] Since the definition applies only to the Transmission Provider or Transmission Owner, the definition does not assert FERC jurisdiction over municipalities that are currently non-jurisdictional. Accordingly, we direct the Midwest ISO to revise these provisions to indicate they apply only to facilities owned, controlled or operated by the Transmission Provider or the Transmission Owner, or both, and are used to provide transmission service.

404. AMP-Ohio asserts the System Impact Study definition should be revised to ensure the Midwest ISO is not permitted to order a study of a municipal distribution system and to be consistent with the definition of Facilities Study that references transmission facilities.[295] Inasmuch as System Impact Studies are done to determine system capabilities in the event new service is requested, the relevant analysis would be on the capabilities of transmission facilities. Therefore, we direct the Midwest ISO to revise its tariff as AMP-Ohio requests.

405. AMP-Ohio contends the definition of Native Load Customers is limited to wholesale and retail power customers of Transmission Owners and ITC participants, and therefore excludes end users within the footprint of the Midwest ISO that are totally dependent on the transmission systems of the Transmission Owners and ITC Participants but do not purchase their power from these entities. AMP-Ohio states the definition should be expanded to cover all end users within the Midwest ISO footprint. We note that this definition is identical to the Native Load definition in the currently effective Midwest ISO OATT, and will continue to apply only to Module B in the TEMT. Inasmuch as that provision has been found to be just and reasonable, and AMP-Ohio has

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[293] *See* TEMT II Order at P 494.

[294] *See Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,027 (2004).

[295] AMP-Ohio would change the second sentence of the definition to say: System Impact Studies for any transmission facilities not under the operational control of the Transmission Provider or ITC shall be performed by the Transmission Owner or applicable ITC Participant or any entity the Transmission Provider designates to perform the studies.

not offered any reasons to indicate the provisions have become unjust and unreasonable other than a general assertion of dependence, we do not have a basis to revise this existing tariff provision and therefore deny rehearing on this issue.

406. Cinergy requests a series of changes to definitions, as listed below, for which it has not provided an explanation. Since we have no basis to determine if the requested revisions would be just and reasonable, we direct the Midwest ISO to comment on these proposals in its next compliance filing. The proposed revisions are shown in brackets.

- <u>Section 1.2</u>: **Actual Interchange** The Interchange value, in MW, [delivered or] received by a Balancing Authority during an Hour.

- <u>Section 1.16</u>: **Available Transfer Capacity** The maximum amount of additional energy that may be carried by the Transmission system under current [or projected] operating conditions.

- <u>Section 1.17</u>: **Balancing Authority** Maintains [Generation Resource to] Load Generation [delete Generation] interchange balance within a Balancing Authority Area and supports interconnection and frequency in real time.

- <u>Section 1.23</u>: **Binding Transmission Constraints** A transmission constraint that causes a change in the dispatch or commitment of one or more Electric Facilities to [avoid or] relieve the constraint limit from being exceeded.

- <u>Section 1.123</u>: **Generator Forced Outage** An immediate reduction in output, Capacity or removal from service, in whole or in part, of a Generation Resource by reason of an Emergency or threatened Emergency, unanticipated failure, inability to return on schedule from a Planned Transmission Outage, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the Business Practices Manuals. A reduction in output or removal from service of a Generation Resource in response to changes in market conditions shall not constitute a Generator Forced Outage. [Cinergy requests clarification on the minimum reduction in output or Capacity to be considered a Generator Forced Outage.]

- <u>Section 1.138</u>: **Hub LMP** Cinergy proposes deleting the entire definition: "The pre-determined, invariant over-time weighted average of LMPs for a particular hour for those Price Nodes that comprise the Hub" with [The weight-averaged LMP for an invariant set of Price Nodes that comprise the Hub. The weights are static over time.]

- Section 1.169: **Load Forecast** : An estimate of the amount of Energy (MWh) or Capacity (MW) to be consumed within the Transmission Provider's Region, prepared by the Transmission Provider based upon input from Control Area Operators and Load Serving Entities, and used in the Transmission Provider's scheduling and dispatch decisions to ensure reliable operation of the Transmission System. [Cinergy requests clarification that the definition means that load served on dynamic schedules outside of the Transmission Provider Region is not included in the Load Forecast while load served on dynamic schedules within the Transmission Provider Region is included in the Load Forecast.]

- Section 1.198: **Metered** Refers to electrical quantities (MW or MWh) that represent the usage or production of energy by Loads or Resources determined with facilities compliant with Transmission Provider Policy [replace policy with metering guidelines].

- Section 1.209: **Net Actual Interchange** The algebraic sum of all metered interchanges over all interconnections between two physically adjacent Control Areas. [replace "between two physically adjacent" with "of the Control Areas"]

- Section 2.1: **Initial Allocation of Available Transmission Capability** For purposes of determining whether existing capability on the Transmission System is adequate to accommodate a request for firm service under this Tariff, the existing transmission reservation queues of the Transmission Owners and ITC Participants will be consolidated into a single Transmission Provider transmission reservation queue, commencing thirty (30) days before the ITC becomes operational, recognizing the priorities existing with respect to the Transmission Owner's or ITC Participants' system. [Cinergy requests clarification as to whether the definition assumes the ITC is not a Midwest ISO member when this process is performed.]

- Section 10.5: **Inclusion of Independent Transmission Companies [and Control Areas]:** For purposes of Module A sections 10.3 and 10.4 above, independent transmission companies under Appendix I of the ISO Agreement [and Control Areas] shall be included in the definition of "Transmission Owner" as used therein and such limitations of liability and damages shall be applicable to those entities.

407. Midwest TDUs propose that the definition of Demand Bid in section 1.65 be revised so that eligibility for submitting non-virtual demand bids is limited to load-serving entities or their suppliers that are actually serving load at their specified locations.

Midwest TDUs assert that bids by others could not be physically absorbed at these locations. We do not have a basis to evaluate the claims made by the Midwest TDUs and therefore direct the Midwest ISO to respond to this proposal.

408. The Midwest TDUs raise a number of definition and interpretation issues for various sections of Module A. The following table lists their issues and our directives to the Midwest ISO by section heading. Other issues are addressed individually in subsequent sections of this order.

Section	**As-Filed Language**	**Issue Identified in Rehearing Request**	**Required Midwest ISO Action**
1.7	Aggregated Price Node (APNode): An aggregation of Price Nodes whose LMP is calculated as a specific weighted average of the LMPs of the constituent Price Nodes.	Weightings must be arithmetically specified, but should be allowed to vary as a function of load. "Specific" should be replaced by "specified." (Midwest TDUs)	Modify the definition to provide in detail what the weighting mechanism is, for, *e.g.*, if it is weighted by load and over what time increment the load is determined.
1.20	Bilateral Transaction: Purchases and/or sales between two market participants.	Need clarification if load and generation of the same affiliated group of companies may be considered separate and distinct market participants, such that a bilateral transaction may be entered from a generation source to an affiliate's load. (Midwest TDUs)	Clarify if load and generation of the same affiliated group of companies may be considered separate and distinct market participants.
1.21	Bilateral Transaction Schedule: A set of MHz values…	"MHz" should be "MW." (Midwest TDUs, Cinergy)	Change MHz to MW.
1.47	Counter Flow Candidate FTR: A candidate FTR that …(iii) would make a nominated Eligible Base CFTR feasible.	Insert "more" before the word "feasible" such that CFCFTRs would include resources that increase simultaneous feasibility without reaching 100 % feasibility. A single CFCFTR will rarely be able to entirely restore another CFTR alone. (Midwest TDUs)	Insert "more" before the word "feasible."
1.66	Demand Response Resource: Load located within the Transmission Provider Region whose withdrawals are monitored by the Transmission Provider.	Definition overreaches by classifying an entire load as a Demand Response Resource even though only a portion is able to curtail in response to dispatch instructions from the transmission provider. (AMP-Ohio) The definition should limit who can be a Demand Response Resource to only that load that has the legal authority to do so. In particular, it should not be read	We agree with Cinergy. The Midwest ISO is directed to amend the definition to limit who can be a Demand Response Resource to only the load with appropriate legal authority.

		to preempt the state's exclusive franchise determination. (Cinergy)	
1.82	Energy Deficient Region: A Load Serving Entity who foresees or is experiencing an Emergency.	A load-serving entity is not an area. Emergencies are declared by the Midwest ISO, not load-serving entities. To solve both problems, the definition should read "An area in which one or more load-serving entities are experiencing or are expected to experience an emergency." (Midwest TDUs)	Change definition to read: "An area in which one or more load-serving entities are experiencing or are expected to experience an emergency."
1.93	External Bilateral Transaction Schedule: A Bilateral Transaction Schedule in which the External Transaction Receipt Point or the External Transaction Delivery Point, lie outside the Transmission Provider Region. When External Transaction Receipt Points and the External Bilateral Transaction Delivery Points are on opposite sides of U.S./Canada boundary, the transaction shall be deemed to take place at the U.S./Canada boundary.	A transaction can't have either external transaction receipt points or external transaction delivery points because they are each defined to be Commercial Nodes, and Commercial Nodes are defined to be Nodes, which are themselves defined to be a point in the Network Model representing a physical location within the Transmission Provider Region. (Manitoba Hydro)	Modify the definitions such that a Bus or a Node represent an electric location (Bus) or a physical location (Node) within the Transmission Provider Region or electrically adjacent External Control Areas modeled in the Transmission Provider Network Model or Commercial Model, or specify why this would not be an appropriate approach.
1.315	Transmission Congestion Credit: The allocated share of total Transmission Congestion Charges credited to each FTR holder.	"Transmission congestion Charges" is not defined in Module A, and should be if it a proper term, and capitalized. (AMP-Ohio, Cinergy)	Provide a definition of Transmission Congestion Credit Charges in Module A.
1.232	Transmission Congestion Payment: A payment to FTR holders equal to the Transmission Congestion Credit Target Allocation for that Hour.	"Transmission Congestion Credit Target Allocation" is not defined in Module A and should be if it is a proper term and capitalized. (AMP-Ohio).	Provide a definition of Transmission Congestion Credit Target Allocation in Module A.

b. Definition of Load

409. Overuse and inappropriate use of the capitalized term "Load" produces a confusing tariff, especially in regards to Module E, according to the Midwest TDUs. They note that according to section 1.1.68, Load is energy that is consumed in the Transmission Provider Region which could be interpreted to mean inside of a Midwest ISO control area. However, Module E, section 68.1.1.b refers to market participants that

serve Load outside of the Transmission Provider Region, and this would conflict with the as-interpreted definition. The Midwest TDUs request a Commission directive that specifies a more refined use of term "Load" to eliminate confusion.

410. We agree with the Midwest TDUs that the use of the term "Load" in the Midwest ISO's tariff is inconsistent and needs clarification. Therefore we direct the Midwest ISO to review the definition of "Load" contained in section 1.168 and clarify whether its intent is to refer only to load within the Midwest ISO region or more broadly to any generic load. If the Midwest ISO determines it is the former, then there are places in the tariff, such as section 68.1.1.b as highlighted by the Midwest TDUs[296] where the requirements of the tariff are muddled by the use of the capitalized term. We also direct the Midwest ISO to revise the tariff so that all uses of the capitalized term "Load" refer to the strict definition contained in section 1.168 and all lower-case uses of load refer to generic load in any region.

2. Miscellaneous Module B Issues

a. Transmission Provider Name and Address

411. The Midwest TDUs request that section 17.1 be revised by deleting "Name and Address" or substituting the Midwest ISO's name and address. The Midwest TDUs state the *pro forma* template for this provision included "[Transmission Provider Name and Address]," as a placeholder that was meant to be filled in. The Midwest TDUs add that if the Midwest ISO can ensure proper handling of its mail, simply specifying a written application to the Midwest ISO (whose mailing address is readily attainable) would suffice.

412. The Midwest TDUs' suggestion appears reasonable. Therefore we direct the Midwest ISO to make the conforming change to its tariff in a compliance filing.

b. References to FTRs

413. AMP-Ohio argues that Module B should state that firm transmission service entitles a holder to a right to request FTRs, and refer to the appropriate Module C sections.

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[296] Midwest TDUs Request for Rehearing at 57.

414. AMP-Ohio's request to incorporate the term "FTR" into Module B appears reasonable. Therefore, we direct the Midwest ISO to reference the sections in Module C relating to the FTR nomination process and FTR auction in Module B, as appropriate.

415. We note that FTRs are held by market participants and represent financial rights, as detailed in Module C. Accordingly, we disagree with AMP-Ohio's contention that firm transmission service entities are entitled to FTRs. Entities with firm transmission service need to become market participants by signing a Market Participant Agreement that binds them to abide by the provisions outlined in Module C. Those provisions relating to FTRs are appropriately in Module C, and have no applicability to Module B service. For these reasons we deny rehearing and direct the Midwest ISO to add a provision to Module B stating that entities with firm transmission service that desire FTRs need to become market participants by signing a Market Participant Agreement and thereby be bound by the provisions of Module C.

c. Attachment J

416. AMP-Ohio renews its protest that the proposed Attachment J, which is referred to in the scheduling provisions, sections 13.8 and 14.6 of the TEMT, rolls back scheduling flexibility contained in the original Attachment J and therefore reduces the quality of service.

417. Attachment J requires that firm and non-firm transmission schedules be submitted 30 minutes prior to the hour, in place of the previous 20 minutes deadline. We agree with AMP-Ohio that Midwest ISO has provided no justification for this change, and therefore we direct the schedule be returned to a 20-minute deadline. We will require the Midwest ISO to submit revised tariff sheets that reflect this change.

d. Point-to-Point Service and Transmission Revenues

418. In the Midwest ISO TOs' initial protest, they stated that the TEMT will cause a significant reduction in internal point-to-point transmission services and a likely drop in transmission revenues for the Midwest ISO TOs. Midwest ISO TOs explained that the TEMT will eliminate much physical transmission and assumes that generators selling into the markets will be designated resources. In the Midwest ISO TOs' request for rehearing, they state the Commission did not directly address their concerns. The Midwest ISO TOs explain that the Midwest ISO Transmission Owners Agreement requires the Midwest ISO to maximize transmission revenues, but the TEMT effectively reduces transmission revenues by an estimated tens of millions of dollars. The Midwest ISO TOs explain that they do not seek to stop or hinder the markets but raise the issue to have it recognized and to request that the issue is addressed.

419. We recognize the Midwest ISO TOs' concern that the TEMT may reduce their revenues. Resources that become designated resources and take network service under the TEMT may be generators that originally took point-to-point service that provided revenues to the transmission owners. At this time, prior to market start, it is difficult for the Commission to evaluate the impact of the TEMT on transmission owner revenues. In the new energy market, transmission owner revenues will be a function of a variety of Module C revenues such as FTRs and balancing market revenue, in addition to revenues from traditional services, expansions and point-to-point service. Short of an actual cost and revenue study for each Midwest ISO TO it is impossible to forecast the exact impact of the TEMT on each Midwest ISO TO's revenue. Moreover, our expectation is that the energy markets will result in improved efficiency, thereby providing additional revenues to participants.[297] We therefore find that the Midwest ISO TOs' request for rehearing on this point is speculative and premature. Parties are free to revisit the issue after market start-up, and come to the Commission with evidence to support their claims. For these reasons, we deny the Midwest ISO TOs' request for rehearing.

e. Penalties for Exceeding Capacity Reservations

420. AMP-Ohio renews its protest that sections 13.7.c and 14.5 provide severe penalties for exceeding firm and non-firm capacity reservations. Also, in the event a penalty is permitted, AMP-Ohio objects to the provision that revenues from the 200 percent charge are applied to reduce Schedule 10 fees, and proposes that the benefits should flow to the zone that paid the embedded cost of the system. If a Transmission Customer exceeds a through-and-out reservation, argues AMP-Ohio, revenues should be credited to all customers taking similar service, and to the extent the overuse is in a particular zone, the customers in the zone should receive the revenue.

421. We will recite our response in the TEMT II Order:

> The penalties in sections 13.7.c and 14.5 of the proposed TEMT relate to penalties for transmission service and are identical to the provisions in the currently effective OATT. The purpose of these penalties is to enforce the tariff provisions that require customers to reserve and pay for the

[297] As the Commission noted in the GFA Order, the centralized economic dispatch feature of the energy market will reduce the need for TLRs that have resulted in unused capacity. The Midwest ISO has also identified additional sales in the new energy market that result in an estimated increase in revenues of $282 million. *See* GFA Order at P 41, 47, 100.

> amount of transmission service capacity that they need. Without such penalties, customers would have an incentive to schedule in excess of their reserved capacity. Accordingly, we consider the penalties reasonable.
>
> Such penalties should not impact customers' decisions in the proposed LMP market. To the extent customers want to schedule amounts above the point-to-point reservation amount or want to schedule at different points than the point of receipt and point of delivery in the point-to-point contract, they can do so by reserving additional point-to-point capacity, firm or non-firm, or by taking network transmission service and thereby avoiding the point-to-point penalty.[298]

422. We believe this answer is responsive to AMP-Ohio's concerns regarding sections 13.7 and 14.5, and that AMP-Ohio has not raised any new arguments as to whether the penalty is severe. Therefore, we deny rehearing on this issue. With respect to the allocation of revenues for the 200 percent charge, we have stated that the first 100 percent reflects the standard rate that would otherwise apply if sufficient capacity had been reserved.[299] Based on this explanation, it is appropriate that revenues from this portion of the charge be allocated to the transmission owner. The remaining 100 percent represents the penalty portion of the charge to discourage unauthorized use of transmission service, and is appropriately allocated to reduce Schedule 10 fees. This allocation reflects that the Midwest ISO must provide dispatch services to manage unauthorized use of the transmission system.

f. Network Service

423. AMP-Ohio renews its protest to section 37.2, contending that the provision results in network service charges for entities that overuse point-to-point transmission, and therefore forces customers to sign network service agreements. Also, AMP-Ohio considers the charges to be penalties, in addition to point-to-point penalties in sections 13.7 and 14.5. It argues that these provisions contravene Commission policy, as enunciated in *PJM Interconnection, L.L.C.*, that transmission providers are not required to offer service that allows a customer to take both point-to-point and network service at

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[298] TEMT II Order at P 498-99.

[299] *See Midwest Independent Transmission System Operator, Inc.*, 103 FERC ¶ 61,282 (2003).

the same discrete point. Finally, AMP-Ohio argues the Midwest ISO should offer contract demand network service, rather than simply charging a penalty.

424. We agree with AMP-Ohio that section 37.2 is an additional charge for service it is already being charged for under point-to-point transmission service, as we discussed in our penalty discussion for sections 13.7 and 14.5. Therefore, we grant rehearing and direct the Midwest ISO to revise section 37.2 to indicate point-to-point customers will not be charged an additional fee for network service when they are paying the 200 percent charge for unauthorized use of point-to-point transmission service.

425. Cinergy asserts that sections 37.3.b and -.c need to be revised to make the Grandfathered Agreement Responsible Entity the party that does not have to pay Schedules 1 through 9 but must pay Schedule 10, rather than the Transmission Owner and ITC Participant, as the provision is currently written. Based on our September 15 Order, we agree that the Grandfathered Agreement Responsible Entity is the correct characterization of the grandfathered agreement entity that has payment responsibilities and therefore we direct the Midwest ISO to make the revision.

426. Cinergy in its Protest raised a series of issues on which it requests clarification. Since the Commission does not have the information necessary to provide answers, we direct the Midwest ISO to respond to these questions.

- Section 13.6: **Curtailment of Firm Transmission Service** Cinergy requests clarification on how the Transmission Provider will determine the amount of load curtailed if interval metering is not in place at the load that is curtailed.

- Section 13.7: **Classification of Firm Transmission Service** Cinergy requests clarification on whether the Transmission Provider plans to evaluate and assess this penalty on an hourly basis and to clarify what is meant by "Third-Party Sales by a Transmission Owner."

- Section 22.2: **Additional Charges to Prevent Abuse** Cinergy requests clarification on whether the additional charge contains Ancillary Services.

- Section 24.1: **Transmission Customer Obligations** Cinergy requests clarification on what is meant by 'compatible metering'.

- Section 33.1: **Procedures** Cinergy requests clarification on how the Transmission Provider will coordinate Curtailment of Load or Load Shedding with neighboring RTOs and/or Control Areas external to the Transmission Provider.

- Section 33.2: **Transmission Constraints** Cinergy requests clarification that actions that are reasonably necessary to maintain reliability will include actions authorized under provisions with PJM and other organizations.

3. Miscellaneous Module C Issues

a. Data Confidentiality

i. Background

427. The TEMT II Order accepted portions of the Midwest ISO's data confidentiality proposal, which it proposed to govern its own and the IMM's disclosure of confidential information to certain recipients under certain conditions. The TEMT II Order found that there were many distinctions between the Midwest ISO's confidentiality proposal and the proposal the Commission had recently approved for PJM, and that the Midwest ISO's proposal may provide for greater access to data than PJM's does.[300] The Commission further noted that as the Midwest ISO and PJM move toward a joint and common market, it will become increasingly important that they have a common means of sharing data with state commissions. Accordingly, the Commission directed the Midwest ISO to work with its stakeholders, and PJM if it desired, to more closely align its confidentiality proposal with PJM's.

428. Additionally, the Commission rejected the Midwest ISO's proposal to share information with state commissions. The Commission found that:

> Neither the Midwest ISO's filing nor the intervenors' comments make clear why OMS and the states seek access to data that is comparable to the Commission's access, how they will keep that data confidential, or for what purpose they will use the data. The Midwest ISO's proposal is broader than the recently-accepted PJM confidentiality policy, and we believe that the two ISOs should have comparable rules as they move toward a joint and common market.[301]

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[300] TEMT II Order at P 557 (citing *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,322 (2004)).

[301] *Id.* at P 561.

429. The Commission directed the Midwest ISO to work with stakeholders and state commissions to develop a consensus proposal governing disclosure of data to state regulatory agencies.[302]

ii. Requests for Rehearing

430. Cinergy argues that the TEMT II Order errs in recommending that the Midwest ISO align its confidentiality proposal with PJM's. It advocates that the Midwest ISO and the IMM should not provide a market participant's confidential information to any requesting entity, including state commissions, without a valid order from a court or government agency to compel release of the information. Cinergy states that the PJM confidentiality provisions offer some protection absent from the Midwest ISO's proposal, but that they continue to expose market participants to "significant risk."[303] Cinergy argues that states already have legal means by which to pursue information and therefore should not have alternative means of accessing confidential data to which they are not legally entitled. It believes that the PJM confidentiality provisions (and therefore the Midwest ISO's provisions, which will draw on PJM's) inappropriately bypass that legal process and the rights established under existing law.

431. Cinergy also argues that the Midwest ISO should be required to change the definition of Confidential Information in section 1.37 of the tariff, to replace the word "patter" with "pattern." Its Request for Rehearing refers back to proposed editorial changes it made to the TEMT in its Protest; those include suggested modifications to section 38.9.

432. PSEG alleges that the Commission erred by failing to clarify, and to place appropriate limitations on, third parties' ability to challenge the designation of market information as "Competitively Sensitive." The TEMT II Order directed the Midwest ISO "to work with its stakeholders to develop a process under which third parties may challenge disclosing parties' designation of information as Competitively Sensitive."[304] PSEG first requests that the term "third party" be defined and narrowed. It argues that many parties, including state commissions and agencies, as well as consumer advocate groups, may seek to challenge the designation of information as "Competitively Sensitive," and that there should be some attempt to limit the universe of challengers in

[302] *Id.* at P 557.

[303] Cinergy Request for Rehearing at 52.

[304] PSEG Request for Rehearing at 12 (quoting TEMT II Order at P 565).

order to avoid burdensome requests. Second, PSEG argues that since the Commission envisions the use of a stakeholder process to develop the challenge process, it is imperative that the Commission provide appropriate guidance to stakeholders so that there are bounds upon the process that are consistent with other provisions of the TEMT that prohibit dissemination of data to market participants. PSEG asks that the disclosing party should be notified of any challenge to its designations and be permitted to defend against any attempt to remove such designations. It believes that any challenger should be required to meet a high threshold in attempting to remove a "Competitively Sensitive" designation.

433. OMS asks the Commission to modify its treatment of state commission's access to confidential data. It requests that the Commission grant rehearing for purposes of further consideration of the issues, and permit OMS an additional 120 days to make an offer of proof that: (1) state commissions have the statutory authority to safeguard confidential data; (2) state commission access to confidential information will advance the Commission's and state commission's common goals for wholesale market reform while preserving the state commissions' legitimate needs.

434. OMS expresses "deep disappointment" with the Commission's disposition of the Midwest ISO's data confidentiality proposal.[305] OMS argues that the Commission, when given a chance to deal cooperatively with OMS on issues of access to confidential information, elected to reject the data access agreement that OMS, the Midwest ISO and the IMM reached cooperatively. OMS points out that stakeholders participated in the open process. It states that while it argued in previous comments that movement toward a joint and common market between the Midwest ISO and PJM has been too slow, it is now having second thoughts that any joint and common market, or any Midwest ISO-administered market, is supportable without adequate state regulator access to data.[306]

435. OMS, in its support for joint and common markets among RTOs, recognized that operational protocols need to be common, but it states that on some matters, such as state commission access to confidential information, it is not clear that a one-size-fits-all approach is essential. OMS states that such an approach ignores the differences in the character of state regulation (i.e., between retail access and non-retail access states). It argues that the Commission's endorsement of the PJM approach precludes consideration of alternative models that may prove advantageous; however, the Commission took this action without identifying aspects of the Midwest ISO proposal that creates conflicts with

[305] OMS Request for Rehearing at 3.

[306] *Id.* at 4-5.

the PJM approach. This unexplained action, OMS argues, violates due process for the Midwest state commissions.

436. OMS argues that two further Commission decisions violate the Midwest state commissions' reasonable due process expectations and rights to hearing under section 206 of the FPA: (1) the Commission's instruction that the Midwest ISO work with stakeholders to develop a revised data confidentiality proposal; and (2) that the revised proposal delete the Midwest ISO's proposal to permit Authorized Requestors to disclose confidential information to other Authorized Requestors. OMS asks the Commission to grant rehearing for further consideration and allow OMS 120 days to offer proof that OMS can sufficiently address the Commission's and stakeholders' legitimate concerns. OMS argues that the Commission should not dictate to OMS and the Midwest ISO an outcome to the upcoming negotiations.

437. OMS also notes that the TEMT II Order required the Midwest ISO and stakeholders to consider Cinergy, Duke and Dynegy's arguments in their protests that market participants should be notified before their confidential information is disclosed to state regulatory commissions. OMS states that it interprets this statement as a suggestion about what should be considered in the stakeholder process, not a requirement as to what must be included in the revised proposal; it seeks rehearing if this is not the Commission's intention.

438. The Commission's decision not to allow OMS to discuss Confidential Information within OMS's own ranks will frustrate OMS's ability to work collaboratively in order to present consolidated work product for the Commission's consideration. OMS states that its member commissions can competently deal with, and protect, confidential information. OMS states that it understands the Commission's concern about "Authorized Requestors," and that if there is more appropriate terminology, it will be willing to consider such language.

439. OMS states that access to confidential information is "unequivocally necessary" for state entities to discharge their legal responsibilities, and that rejection of the filed language is inconsistent with the breadth of functions that the Commission and OMS have contemplated for OMS and for Regional State Committees in general.[307] OMS states that its members have an obligation to protect their ratepayers from market power abuse and anticompetitive behavior, and that if the price of power in the wholesale market is subject to manipulation, there is real potential for harm to ratepayers. Without access to confidential information, OMS argues, it is impossible for anyone to determine

[307] *Id.* at 8.

whether aberrant prices in the wholesale market are the result of genuine transmission system issues or price manipulation.

440. OMS argues that the protests do not cite specific examples where a state commission's handling of confidential information resulted in a leak that resulted in irreparable harm to a market participant. It therefore questions the basis of the Commission's decision regarding the provision of confidential information to state commissions.

441. Next, OMS argues that it finds worrisome the Commission's reference to the purposes for which state commission will use confidential information. OMS states that the Commission must not assume that state commissions are ceding responsibilities to the Commission. Rather, OMS argues that because of their state statutory authorities, state commissions have authority to obtain confidential information from jurisdictional utilities. OMS argues that if the Commission expects OMS to make recommendations on market readiness, the OMS members have every right to expect information on the subsequent functioning of that market.

442. Minnesota Department of Commerce supports OMS's comments. It further argues that it is concerned about the data access issue if the final outcome parallels the Commission's ruling in *PJM Interconnection, L.L.C.*,[308] because few state agencies in the PJM region are allowed access to data. Minnesota Department of Commerce notes that *PJM Interconnection, L.L.C.* did not provide a route for state agencies that are not public utility commissions to obtain confidential market information that is not obtainable from the state's jurisdictional public utilities. It states that the structure of the utility regulatory agencies in Minnesota requires specific consideration concerning the provision of access to data to allow the Minnesota Department of Commerce to carry out its statutory responsibilities.

443. Minnesota Department of Commerce argues that it is the investigatory and enforcement arm of the Minnesota Commission, and that access to confidential data is essential for it to perform its statutory function. It notes that the Midwest ISO, through its stakeholder process, agreed that access to such information is necessary for state commissions to carry out its responsibilities. Accordingly, the Minnesota Department of Commerce states that it is imperative that the Commission reconsider its rejection of the Midwest ISO's proposal for state access to confidential data.

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[308] 107 FERC ¶ 61,322 (2004) (accepting, subject to modification, revised tariff sheets implementing procedures under which PJM and its market monitor provide confidential information to state commissions).

iii. Discussion

444. In the September 30, 2004 Confidentiality Order, the Commission granted OMS's request for rehearing for purpose of further consideration. The Confidentiality Order also granted OMS the 120 days it requested to make an offer of proof that: (1) state commissions have the statutory authority to safeguard confidential data; (2) state commission access to confidential information will advance the Commission's and state commissions' common goals for wholesale market reform while preserving the state commissions' legitimate needs. It also held in abeyance, pending OMS's submission of the Offer of Proof and our further order, the requirement that the Midwest ISO file modifications to its confidentiality proposal within 60 days of the date of the TEMT II Order. Accordingly, we will defer the issues that OMS and the Minnesota Department of Commerce have raised for a future order. The future order will consider OMS's Offer of Proof and the parties' responsive comments.

445. We will also defer Cinergy's request for rehearing. Cinergy's argument that the Commission erred in recommending that the Midwest ISO align its confidentiality proposal with PJM's reflects concerns about disclosure of data to state commissions under either proposal. The Commission did not direct the Midwest ISO to revise its confidentiality proposal to make it identical to PJM's, so Cinergy's arguments about state access to confidential data are premature in light of the further process still needed to develop a confidentiality proposal.

446. We will grant Cinergy's request for rehearing with respect to changing the definition of Confidential Information in section 1.37 of the tariff. If the Midwest ISO and stakeholders wish to retain the notion of a pattern in this section, the Midwest ISO's compliance filing on confidentiality issues should replace the word "patter" in section 1.37 of the tariff with "pattern."[309] We deny its request for the changes to section 38.9 that it proposed in its May 7, 2004 Protest. As stated in the TEMT II Order, further process is needed to refine the Midwest ISO's data confidentiality proposal.[310] The Confidentiality Order represents the first step of that process, as it permits OMS to offer further proof about the efficacy of the proposal to share data with state commissions.[311] We will not prejudge the outcome of further discussions regarding confidentiality by accepting changes to the TEMT now; however, Cinergy may raise its concerns in that

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[309] *See* TEMT II Order at P 563-64.

[310] *Id.* at P 561.

[311] *See* Confidentiality Order at P 11-12.

stakeholder process and in response to the Midwest ISO's revised confidentiality proposal.

447. PSEG's request for rehearing is denied in light of the further proceedings that will be necessary to develop a revised data confidentiality proposal. The Commission returned the data confidentiality proposal to the stakeholder process in order to allow stakeholders to develop a consensus as to what it should be. Granting PSEG's requests for rehearing would deny other stakeholders the opportunity for input on the questions of who should be able to challenge the designation of market information as "Competitively Sensitive," what steps should be taken in this process and what burden a challenging party must meet. PSEG will have an opportunity to make its views known during the stakeholder process and to file a protest to the Midwest ISO's revised confidentiality proposal, when that revision is filed with the Commission.

b. Self-Scheduling Entities as Market Participants

i. Background

448. The Commission accepted the Midwest ISO's proposed congestion management plan and found that it did not violate section 201(b)(1) of the FPA, as no aspect of the tariff applies to retail rates or services. Moreover, the order found that participation in the energy tariff is voluntary; load-serving entities can self schedule all of their generation sources rather than buying and selling in the Midwest ISO market. Accordingly, the TEMT provides load-serving entities with another means of providing least-cost service to its customers. However, the Commission did clarify that load-serving entities choosing to become market participants are subject to charges under the tariff, even if they self schedule all or a portion of their load.

ii. Requests for Rehearing

449. LG&E, Montana-Dakota, and Midwest ISO TOs contend that the TEMT II Order constitutes reversible error, arguing that the requirement to operate their generation facilities under mandatory federal requirements, *i.e.*, the TEMT, violates FPA section 201(b), which reserves jurisdiction over a regulated utility's generating facilities and

retail sales to the states exclusively. LG&E argues that the TEMT requires public utilities to become Market Participants[312] by making their generation facilities available to the Midwest ISO "pool," even if utilities wish to use their generation resources solely to self-serve their in-state native load. Also, according to LG&E, the TEMT expands federal jurisdiction over retail sales of electric energy to bundled load since it mandates that LG&E obtain energy from the pool, and, therefore, some portion of state-jurisdictional bundled retail sales service becomes "converted" into wholesale sales for resale. Midwest ISO TOs argue that the self-scheduling provisions of the TEMT violate section 201(b) of the FPA, because self-scheduling will occur pursuant to a tariff provision filed with the Commission, with disputes resolved by the Commission, not states, even though the issue would involve dispatching of a load-serving entity's generation to serve its retail loads, without using the Midwest ISO markets.

450. LG&E contends that section 39.2.10 ensures entities seeking self-schedule of their entire load and resources will be drawn into the Day 2 market, and section 39.2.11 will have the same effect, making market participation mandatory rather than voluntary. LG&E argues that this is inconsistent with the markets proposed by the Standard Market Design (SMD) NOPR, as these were to be voluntary. LG&E objects that these provisions thwart the use of balanced, bilaterally scheduled transactions designed to avoid market participation. Therefore, argues LG&E, the Midwest ISO should exempt balanced, bilaterally scheduled transactions from the Day-Ahead surplus and shortage clearing methodologies and thereby ensure the option to entirely forego participation in the energy markets is maintained. In the alternative, LG&E recommends rejection of this section of the tariff.

451. Montana-Dakota disputes the claim in the TEMT II Order that there is no mandatory requirement for load-serving entities to purchase energy under the TEMT to serve retail electric service customers, and asserts that the TEMT will prevent load-serving entities from relying exclusively on their own generation resources to serve native load. Montana-Dakota further claims the requirement of load-serving entities to participate in energy markets is contrary to Order No. 2000[313] and Order No. 888[314] that

[312] The TEMT defines Market Participant as: "An entity that (i) has successfully completed the registration process with the Transmission Provider and is qualified by the Transmission Provider as a Market Participant, (ii) is financially responsible to the Transmission Provider for all of its Market Activities and obligations, and (iii) has demonstrated the capability to participate in its relevant Market Activities." Module A, section 1.184, Original Sheet No. 95.

[313] *See* Order No. 2000 at 31,033.

state RTO participation is voluntary, and that the Commission can not expand the scope of its authority beyond that set forth in the FPA. As an alternative, Montana-Dakota proposes modifying the TEMT through appropriate incentives that ensure that all load-serving entities and their customers realize the economic benefits from participating voluntarily. Such an approach, contends Montana-Dakota, would ensure equitable sharing of the benefits of the TEMT and avoid undue burdens on some participants. Montana-Dakota also proposes the Midwest ISO agree to hold-harmless conditions such as those applicable to utility mergers so that transmission customers are protected from potential adverse consequences of participating in the TEMT.

452. Otter Tail contends that the TEMT requires mandatory participation, and instead should be voluntary, consistent with the FPA and court precedent. Otter Tail states there is no provision in the FPA that provides the Commission with the authority to compel a customer to take service under a tariff, and that practice over the decades has been for tariffs to be available for customer use and customers have the choice of whether or not to contract to take service.[315] Furthermore, Otter Tail argues the TEMT is contrary to other tariff provisions[316] as well as the platform of Order No. 2000.[317] Finally, Otter Tail cites to a conclusion by the United States Court of Appeals for the District of Columbia that Order No. 2000 does not mandate RTO participation[318] as a basis for its rehearing

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[314] *See* Order No. 888 at 31,654.

[315] *See id.* at 31,036, Appendix D §§ 17, 18, 29 (not requiring customers to take service but allowing them to elect by contract to do so); *Cincinnati Gas & Electric Company*, 69 FERC ¶ 61,005 at 61,037 (1994) (not requiring Cinergy to reserve transmission capacity over AEP's system where loop flows occurred over the AEP system, consistent with good utility practice, but explaining that if "loop flows occur that are consistent with good utility practice, AEP may come to the Commission and seek appropriate compensation or request appropriate relief by way of a complaint.").

[316] *See New PJM Cos.*, 107 FERC ¶ 61,272 (2004).

[317] *See Regional Transmission Organizations,* Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 at 31,089 (2000), *order on reh'g* Order No. 2000-A, 65 Fed. Reg. 12,088 at 31,092 (Feb. 25, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd Public Utility District No. 1 of Snohomish County, Washington v. FERC,* 272 F.3d 607 (D.C. Cir. 2001).

[318] *See Public Utility District No. 1of Snohomish County, Washington v. FERC,* 272 F.3d 607, 617 (D.C. Cir. 2001).

request.

453. Midwest ISO TOs request clarification on whether section 38.2.5 makes a self-scheduling transmission owner serving its native load with its own generation subject to approximately 25 charges levied on market participants, or whether a load-serving entity that self-schedules must become a market participant. Joint Cooperatives raise similar concerns, stating that self-scheduling load-serving entities that do not want to participate in energy markets should not be required to be market participants or be subject to the costs imposed on participants in the energy markets. Montana-Dakota also expresses concern regarding the increased costs associated with the proposed energy markets, such as Schedules 16 and 17, staff costs to support the energy market, marginal loss impacts, the cost of congestion, imbalance and general uplift associated with market participation.

454. Montana-Dakota states it should not be required to participate in the TEMT absent evidence that its customers will benefit. Montana-Dakota asserts the Midwest ISO's estimate of more than $700 million in savings per year[319] is conjecture, not subject to discovery or cross-examination. Montana-Dakota asserts that potential savings from its participation would be minimal at best, since it is a low-cost energy producer, so it would not be buying from the market, and it does not anticipate an increase in sales to other utilities.

iii. Discussion

455. LG&E, Montana-Dakota, Otter Tail, and Midwest ISO TOs raise few new issues for consideration. The central question raised is whether the TEMT's requirement for entities to register, *i.e.*, sign the necessary paperwork, to become market participants makes participation in the Midwest ISO energy markets mandatory.

456. LG&E errs when it asserts that participation in the TEMT markets is not voluntary. The TEMT does require any entity that wishes to engage in "Market Activities,"[320] including buying and selling in the TEMT markets, self-scheduling to

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[319] *See* McNamara testimony (June 25, 2004).

[320] Market Activities are defined as "[t]ransactions and actions taken by Market Participants through the Energy Markets such as purchases and/or sale of Energy. Market Activities include holding, selling and/or purchasing FTRs, as well as Internal and External Bilateral Transactions. Further, section 1.282 defines Self-Scheduled Resource as "A Generation Resource that is scheduled by a Market Participant and controlled by the same Market Participant under the overall coordination of the Transmission Provider….." Module A, section 1.182, Original Sheet No. 95.

serve native load, and engaging in bilateral transactions, to fill out the requisite paperwork and become a Market Participant. Becoming a market participant, however, is only an eligibility requirement to allow participation in market activities – it does no more.

457. Most importantly, the TEMT does not require a market participant to buy or sell energy through the TEMT markets. LG&E and others have attempted to stretch the requirement to become a market participant into a requirement to turn over control of its retail load-serving generating units to the Midwest ISO. The tariff has no such requirement. The fact the TEMT requires those requesting to engage in market activities to sign on as market participants does not obligate that entity to turn over generation assets to the Midwest ISO. Any entity, or its agent,[321] that signs up as a market participant, has a choice of how to meet its load under the tariff. It can: (1) designate all of its generating resources as self-scheduled and thereby serve all of its retail load with generation in the same way as if there was no Midwest ISO energy market, or (2) designate all or a portion of its resources as Network Resources, and serve its load wholly or in part through the Midwest ISO markets, as well as engage in bilateral transactions. Therefore, LG&E has the option of choosing whether or not to make its generation facilities available to the Midwest ISO energy market.[322] Under the TEMT, LG&E can use its generation resources solely to self-serve its in-state native load. Accordingly, as we previously held, the TEMT does not mandate changes to an integrated utility's supply chain and, therefore, neither expands federal jurisdiction nor violates section 201(b) of the FPA, as claimed by LG&E.[323]

458. Our actions here are consistent with Order No. 2000 and the Commission's intent that energy markets such as those proposed by the Midwest ISO be voluntary. First, as noted above, the TEMT does not require anyone to buy and sell through the central market.[324] Moreover, as we have noted in previous orders, Order No. 2000 requires that

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[321] *See* Module C, section 38.3, Original Sheet Nos. 423-24.

[322] Only if LG&E designates its resources as Network Resources will they be included in the Midwest ISO energy market.

[323] TEMT II Order at P 574-75.

[324] We do note, however, that transmission customers are required to settle imbalances at real-time prices generated by the energy market, rather than paying the current tariff's imbalance charges.

RTOs develop a congestion management plan.[325] The TEMT II Order approved the LMP congestion management proposal filed by the Midwest ISO under section 205 of the FPA, finding that the proposal was just and reasonable. LG&E, as a customer under the Midwest ISO OATT, is subject to any and all revisions, whether routine or extensive, filed for and accepted under section 205 of the FPA. Because the Commission has found that the Midwest ISO's tariff changes to be just and reasonable, LG&E, like all customers under the Midwest ISO tariff, is bound by its terms. As we stated in the TEMT II Order, no aspect of this arrangement applies to retail rates or services; hence there is no violation of FPA section 201(b)(1). For this reason, we deny rehearing of Midwest ISO TO's jurisdictional issue.

459. Further, we deny LG&E's request to be able to "opt out" of various sections of the tariff. As we have explained, the TEMT permits LG&E to choose whether any or all of its resources will be committed to the Midwest ISO markets. Only the portion of those units designated by a market participant as Network Resources are committed to the Midwest ISO markets. Thus, because LG&E already has the ability to choose to keep all of its resources out from under Midwest ISO's control, there is no need to create another mechanism for LG&E to opt out of this portion of the tariff.

460. Moreover, as we explained in the TEMT II Order, addressing similar concerns raised by Otter Tail:

> Otter Tail's request to be exempt from just the Energy Markets portion of the TEMT fails to recognize the interplay of the Energy Markets, scheduling and congestion management portion of the tariff (Module C) with the transmission service portion (Module B). The LMP congestion management system inextricably intertwines the

[325] *See Midwest Independent Transmission System Operator, Inc.*, 97 FERC ¶ 61,326 at 62,511 (2001), *reh'g denied* 103 FERC ¶ 61,169 (2003). We disagree with LG&E's statement that Order No. 2000 rejected LMP pricing as a requirement for RTOs. *See* LG&E at 6. The relevant language of Order No. 2000 indicates the Commission encouraged flexibility: "Therefore we will allow RTOs considerable flexibility to propose a congestion pricing method that is best suited to each RTO's individual circumstances." Order No. 2000 at 31,127.

> Day-Ahead and Real-Time Markets and their associated congestion management system with the scheduling and provision of transmission service.[326]

461. That order also recognized that, in order to fulfill that responsibility and exempt Otter Tail from just the energy markets, the Midwest ISO would have to create and administer a separate transmission tariff in addition to the TEMT, and neither Otter Tail nor Midwest ISO have proposed such a tariff. Similarly, LG&E has not persuaded us that is necessary to, nor explained how it would be implemented, if we were to permit LG&E to opt out of certain discrete provisions in the TEMT.

462. Several parties also appear to be seeking to limit their liability for paying for the costs of the Midwest ISO markets. The parties reason that, if they serve their load with their own generators, they are not making use of the Midwest ISO markets and, therefore, should not have to pay for them. However, we have previously found that all load serving entities in the Midwest ISO footprint receive benefit from the existence of the Midwest ISO markets. These benefit comes not only from the opportunity to directly buy and sell power through a centralized market, but also from the price transparency the market creates, more reliable and efficient dispatch and transmission system usage, and the ready availability of a market to dispose of excess energy and resolve real-time imbalances at market prices, not penalty rates. This is the reason for not limiting market charges to just the buyers and sellers in the market, but applying them to all market participants. As we explained in detail in our order establishing the Schedule 16 and 17 charges, even if self-scheduling entities and parties to bilateral transactions are not directly buying and selling in the energy markets in a given hour, they benefit from its existence.[327] At that point, WEPCO will be able to consider the entire Midwest ISO footprint in the market power analysis supporting a request to make sales everywhere in Midwest ISO under a revised market-based rate authorization.

c. Applicability of Market-Based Rate Authority To Market Participants

463. WEPCO requests clarification that it can participate in the energy markets without first seeking broader market-based rate authority. WEPCO explains that it currently only

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[326] TEMT II Order at P 618.

[327] *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,235 at P 49 (2004).

has market-based rate authority for energy sales outside WUMS[328] and that energy sales within WUMS are made pursuant to its cost-based sales tariff. To retain market-based rate authority, WEPCO must follow the Commission's review procedures regarding market-based rate authority (*i.e.*, three-year market-based rate review), and to request market-based rate authority in geographical areas previously excluded WEPCO must file an application with the Commission seeking to amend its existing market-based rate tariff.[329] We note that the Midwest ISO-wide market will not be considered as the default geographic market until such time as the Midwest ISO becomes a single market and performs functions such as single central commitment and dispatch with Commission-approved market monitoring and mitigation.[330] The Commission will make such a determination in a separate order.

d. Generator Outages

i. Background

464. Section 38.2.5.h of the TEMT, approved in the TEMT II Order, states that the Midwest ISO shall coordinate Generator Planned Outages. The section requires that market participants submit their outage schedules to the Midwest ISO and also provides that the Midwest ISO shall inform market participants if their schedules will have a material impact on the reliability of the Midwest ISO region, and reschedule outages when faced with a documented reasonable expectation of an emergency. Market participants with rescheduled outages will be compensated for reasonable and explicit additional costs, excluding opportunity costs. Generator rescheduling procedures will be applied non-discriminatorily and filed at the Commission.

ii. Requests for Rehearing

465. Cinergy contends that the procedures in section 38.2.5.h for rescheduling generator outages are unreasonable because: (1) they do not specify the criteria that the Midwest ISO must use in evaluating outage rescheduling; (2) there is no process provided for challenges; (3) there is not a mechanism for ensuring maximum notice to the generation owner; and (4) the provisions do not provide clear rights to full compensation. Cinergy also argues that the Midwest ISO should be directed to submit a compliance

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[328] *See Wisconsin Electric Power Company*, 82 FERC ¶ 61,067 (1998).

[329] *See AEP Power Marketing, Inc., et al.*, 107 FERC ¶ 61,018 (2004).

[330] *See id.* at P 188.

filing, subject to notice and comment, setting forth criteria for taking into account the various factors that inform a decision to schedule an outage, that notices be provided no later than 30 days from the submission of a generator planned outage schedule, and that Midwest ISO notify the affected generation owner of a potential need to reschedule a planned outage as soon as it has knowledge of a pending emergency. Cinergy also requests that Midwest ISO set forth a list of factors considered in determining whether a market participant's schedule should be altered for stakeholder review and comment before their inclusion in the tariff. Finally, Cinergy seeks clarification that market participants have full notice and comment rights with respect to the compensation provided and urges the tariff be revised to require reimbursement within 30 days after the market participant submits a notice of reimbursable costs, with dispute resolution procedures provided.

iii. Discussion

466. As we noted in the TEMT II Order, section 38.2.5.h provides the Midwest ISO will reschedule generator outages after it has a documented, reasonable expectation of an Emergency. An Emergency, per section 1.80, is: (1) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm Load, equipment damage, or tripping of system elements that could adversely affect the reliability of any electric system or the safety of persons or property; (2) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (3) a condition that requires implementation of Emergency procedures as defined in this Tariff and the Business Practices Manuals. We consider this listing of conditions for outage rescheduling to be clear and comprehensive criteria. Also, we recognize the Midwest ISO needs to have the ability to act quickly and effectively to respond to reliability issues, and should not be constrained by compliance filings, notice requirements and stakeholder reviews for situations that may require split second decisions. Therefore, we deny rehearing on Cinergy's requests. Cinergy is free to bring issues to the Commission's attention, either as filings or complaints, after the Emergency situations have been addressed. We clarify that such filings would be the appropriate venue to address Cinergy's concerns that it may not receive full compensation for outage rescheduling.

e. Liability Issues

i. Background

467. A number of protestors to the March 31 Filing sought clarification and modification of the liability and indemnification provisions for entities undertaking proposed functional responsibilities under the Midwest ISO's direction, as well as for

recovery of costs associated with assumption of those responsibilities. The TEMT II Order required the Midwest ISO and its control areas to negotiate "before a settlement judge the proper allocation of functional responsibilities, costs and liability associated with the Midwest ISO's new role in its region" and to make a filing presenting a proposed resolution.[331]

ii. Requests for Rehearing

468. Reliant argues that the Commission should clarify the TEMT II Order's description of the settlement proceeding established to allocate operational responsibilities between the Midwest ISO and the transmission owners. Reliant notes that the language of the order described the settlement proceeding as a discussion between the Midwest ISO and the transmission owners. It asks that the order be clarified to address limitation of liability protection and rights to indemnification of market participants and generation owners, with the directive that any resulting provisions be comparable to those provided to the Midwest ISO and the transmission owners.

469. If the Commission does not make this clarification, then Reliant asks the Commission to separately order the Midwest ISO to revise section 10 of the TEMT to provide for limitations of liability and rights to indemnification for market participants and generation owners that correspond to those of the Midwest ISO and transmission owners. Reliant argues that leaving market participants and generation owners exposed to third-party lawsuits while protecting the Midwest ISO and transmission owners fails to acknowledge the realities of the restructured energy markets. It states that market participants and generation owners will be required to: (1) conduct their operations in accordance with various operational standards; and (2) comply with the Midwest ISO's orders regarding dispatch signals in addition to assuming liability for fulfilling and deviating from those schedules. Given this "fundamental level of operational responsibility," Reliant argues that to leave market participants and generation owners without protection from liability unduly and unfairly singles them out for exposure to third-party lawsuits and jury verdicts. Reliant advocates that: (1) market participants and generation owners be afforded the same limitation on liability as the Midwest ISO and transmission owners, including limiting their liability to direct damages only; and (2) market participants and generation owners should have the right to seek indemnification from other entities under the TEMT, including the Midwest ISO, transmission owners, other market participants and other generation owners, to the extent that the indemnifying party causes the indemnified party damage or loss.

[331] TEMT II Order at P 126.

470. Alternatively, Reliant argues that the Commission should order the Midwest ISO to utilize its stakeholder process to discuss and reach, before market start-up, conclusions and solutions about market participant and generation owner liability protections. Reliant requests that the Commission set a deadline for resolution of this issue so that the necessary changes to the TEMT can take place prior to market start-up.

471. Detroit Edison states that while the TEMT II Order directed parties to enter into negotiations on the issue of parties' liability for actions taken pursuant to Midwest ISO instructions, the TEMT II Order should have affirmatively stated that parties engaged in control area operations should be shielded from liability when acting pursuant to Midwest ISO instructions. The unreasonableness of this situation, it says, is magnified because electric system reliability and obligations to serve load are implicated. Detroit Edison also argues that the Commission erred by not affirmatively stating that the Midwest ISO, coincident with its assumption of control over functions needed to meet utility service obligations, should assume liability for a utility's failure to meet its obligations to serve when that failure is a result of the Midwest ISO's failure to properly perform functions that it will take on under the TEMT.

472. Cinergy states that its concern about liability for activities taken at the Midwest ISO's direction was not limited to control area activities because the TEMT would give the Midwest ISO authority to direct actions of a wide variety of market participants. Cinergy is concerned that if it is acting not as a control area, but in some other capacity, the limitations on liability developed at the settlement conference may not apply. Cinergy seeks clarification, or in the alternative, rehearing, that the liability protection pertains to all activities taken by market participants at the Midwest ISO's direction.

473. AMP-Ohio requests rehearing of the Commission's acceptance of section 10.2 in the TEMT II Order, stating that the Commission did not address its May 7, 2004 protest regarding section 10.2. AMP-Ohio renews its assertion that municipals in Ohio cannot lawfully provide the broad indemnity required by section 10.2 of Module A.

474. AMP-Ohio states that its lack of legal authority to grant the indemnification required by section 10.2 has been proven repeatedly in Ohio Attorney General opinions.[332] AMP-Ohio states that before a governmental entity in Ohio can agree to indemnify a private party without creating a debt in violation of Ohio Constitution Articles II, VIII, and XII, as applicable, the following criteria must be satisfied: (1) the

[332] AMP-Ohio Protest at 10-11 (May 7, 2004) (citing Opinion No. 99-049, 1999 Op. Atty Gen. Ohio, 1999 Ohio AG LEXIS 49 (September 21, 1999); and Opinion No. 96-060, 1996 Ohio AG LEXIS 53 (November 21, 1996)).

indemnification requirement cannot survive the expiration of the agreement; (2) the maximum amount for which indemnification can be received must be established and set forth in the agreement; and (3) the governmental entity must appropriate that amount and certify it to the agreement. AMP-Ohio contends that these three criteria cannot be met if they comply with section 10.2. Further, taxpayers cannot be obligated to pay for the losses of private entities, an indemnification obligation by the governmental entity constitutes the lending of aid and credit to a private entity, in violation of Article VIII, section 6 of the Ohio Constitution. Therefore, AMP-Ohio contends that waiver provisions to section 10.2 should be included in the tariff for those parties that cannot legally comply.

iii. Discussion

475. The TEMT II Order instructed the Midwest ISO and the Transmission Owners to negotiate the proper allocation of liability associated with the Midwest ISO's new role in its region.[333] Those parties filed a proposal – the Balancing Authority Settlement – on October 5, 2004, and the Commission will consider its merits in a future order.

476. The Commission held in the TEMT II Order that the discussions regarding limitation of liability should be limited to the Midwest ISO and the Transmission Owners, and therefore foreclosed the potential that the settlement process would produce a provision regarding limitation of liability for generators or market participants. We agree with Reliant and Cinergy that the discussions of liability in the energy markets should have been more comprehensive than what we have ordered, and that they should have included generators and market participants. We will grant their requests for clarification on this point.

477. Given the limited time before the inception of the energy markets, and the fact that a settlement has already been filed, we believe that reopening the settlement process would greatly disrupt this proceeding. As previously stated, the Commission will evaluate in a future order the proposed settlement agreement pertaining to the allocation of functional responsibilities, costs and liability associated with the Midwest ISO's new role in its region. In order to satisfy Reliant's and Cinergy's concerns, we will require the Midwest ISO to make a further compliance filing 30 days after the date of our order on the settlement agreement. The compliance filing should propose liability provisions for generators and market participants who act in good faith in following the Midwest ISO's directives.

[333] TEMT II Order at P 138.

478. We will deny Detroit Edison's requests for rehearing, which seek for the Commission to dictate the outcome of the negotiations regarding liability. The Commission's experience, as it stated in the TEMT II Order, is that negotiating resolutions to issues such as limitations of liability is preferable to litigating those issues. It would have simply invited litigation to limit ahead of time the potential range of outcomes of the negotiations. Detroit Edison has had an opportunity to raise objections to the outcome of the settlement process, and we will address any such objections in our upcoming order on the settlement agreement.

479. We agree with AMP-Ohio that the Commission did not address their comments on the indemnification requirements of section 10.2 in the TEMT II Order. We grant AMP-Ohio's request for rehearing of section 10.2 of Module A. We find its arguments convincing that the broad indemnity the Midwest ISO seeks may violate Ohio laws under reasonable scenarios for tariff customers and market participants. However, we will not direct the Midwest ISO to add a waiver provision to section 10.2. Instead we direct the Midwest ISO to review AMP-Ohio's waiver request (working with stakeholders if it desires) and to either grant the waiver to municipal entities or narrow its requirements sufficiently so that all tariff customers may legally comply. We direct the Midwest ISO to file the result of this stakeholder process within 60 days of the issuance of this order.

f. Standards of Conduct

i. Background

480. Section 38.6 details obligations of Control Area Operators, including performing reliability functions according to NERC and Regional Reliability Council requirements and requires that these entities comply with the Commission's standards of conduct. This section further provides that any company's division, personnel or Affiliates designated as a Control Area Operator and is also a market participant must comply with the Commission's standards of conduct. Divisions, personnel of Affiliates of companies that are in compliance with the Commission's standards of conduct are eligible for market participant status.

ii. Requests for Rehearing

481. Cinergy contends that section 38.6 should be stricken since the Midwest ISO is not the proper forum for determining compliance with the Standards of Conduct, offers no due process rights and is not an adjudicatory body.[334] Section 38.6 states, in relevant

[334] *See United States Telecom Ass'n v. FCC*, 359 F.3d 554, 566 (D.C. Cir. 2004).

part, "…[o]nly divisions, personnel, or Affiliates of a company that is in compliance with Commission's standards of conduct to the satisfaction of the Transmission Provider shall be eligible for status as a Market Participant." Additionally, Cinergy considers the tariff penalty – loss of market participant status – to be too severe compared to the penalties contemplated in Order Nos. 2004,[335] 2004-A,[336] or 2004-B.[337] Instead, according to Cinergy, the Midwest ISO should report infringements of the Standards of Conduct to the Commission.

482. The Midwest TDUs request clarification that the Commission's standards of conduct articulated in Order Nos. 2004 and 2004-A apply to control areas even in the event the Control Area Operator divested its transmission facilities, as required by Order No. 2000[338] since these entities still receive commercially sensitive information that could be used to gain an unfair competitive advantage. Also, Midwest TDUs request that section 38.6.7 be clarified to take account of waivers, as discussed in the TEMT I Order.[339]

iii. Discussion

483. We agree with Cinergy that the Midwest ISO is not an adjudicatory body, and therefore cannot make determinations on compliance with the Standards of Conduct or on remedies for the noncompliance. We direct the Midwest ISO to revise section 38.6 to reflect the fact that only the Commission may determine whether a company is in compliance with the Standards of Conduct, and the Commission will determine the remedy for any noncompliance.

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[335] *See Standards of Conduct for Transmission Providers*, Order No. 2004, FERC Stats. & Regs. ¶ 31,155 (2003).

[336] *See Standards of Conduct for Transmission Providers*, Order No. 2004-A, FERC Stats. & Regs. ¶ 31,161 (2004).

[337] *See Standards of Conduct for Transmission Providers*, Order No. 2004-B, 108 FERC ¶ 61,118 (2004).

[338] *See* Order No. 2000 at 31,104.

[339] *See* TEMT I Order at P 35, 51.

484. We clarify that the Commission's Standards of Conduct continue to apply to Control Area Operators that have divested transmission facilities and have not obtained the necessary waivers. Such entities may be market participants or affiliated with market participants, and therefore would have an unfair competitive advantage from information provided to the Control Area Operator. With respect to the waiver language request of the Midwest TDUs, we note that section 38.6 states control area operators that are also market participants must comply with the Commission's Standards of Conduct, or have the appropriate waivers in place. Section 38.6.7 require that data provided to control area operators be provided in accordance with the Commission's Standards of Conduct. We grant the Midwest TDUs request to revise this provision to state that the Standards of Conduct apply, unless the appropriate waivers are in place and direct the Midwest ISO to make this revision.

g. External Resources and Load

i. Background

485. Section 38.2.5.a.ii of the TEMT requires that market participants operate Resources within the Transmission Provider Region in a manner consistent with the standards, requirements or directions of the Transmission Provider, with the proviso that market participants will not be required to take any action inconsistent with Good Utility Practice or applicable law. Section 38.1.6 of the TEMT establishes the operational functions and responsibilities of the Transmission Provider, as Reliability Authority. Such functions include receiving operational data from market participants, calculating interconnection operating limits, mitigating congestion with SCED and SCUC, directing revisions to transmission maintenance programs, rescheduling generator outages, and issue reliability alerts and corrective actions. Section 39.2.2 of the TEMT provides procedures for bids by market participants that intend to purchase Energy in the Day-Ahead Energy Market. Market participants must demonstrate that they are Load Serving Entities or purchasing on behalf of Load Serving Entities to submit Demand Bids.

ii. Requests for Rehearing

486. Manitoba Hydro requests that the Midwest ISO be directed to narrow the scope of section 38.2.5.a.ii so that it applies only to generation resources within the Midwest ISO region and applies only to directions that are authorized by the TEMT. Alternatively, Manitoba Hydro requests that the Midwest ISO be directed to modify the TEMT such that external market participants are obligated to operate their external resources consistent with their offers and bilateral transaction schedules, rather than with the Midwest ISO's direction.

487. Manitoba Hydro contends that it is subject to other authorities that determine its operating limits, transmission maintenance plans, generator outages and decommissioning plans, and that granting the Midwest ISO authority over these matters would create conflicts that would preclude their participation in Midwest ISO Energy Markets. Therefore, Manitoba Hydro requests that the Midwest ISO be directed to revise the provisions of section 38.1.6 relating to Reliability Authority responsibility for interconnection reliability operating limits, revisions to transmission maintenance plans, generator planned outages, and corrective actions so they only apply to Generation Resources within the Transmission Provider Region or, alternatively, to entities for whom the Midwest ISO acts as Reliability Authority under contracts that grant that authority.

488. Manitoba Hydro seeks clarification that an entity serving load that is not directly attached to the transmission system is not a load-serving entity, for purposes of determining eligibility to submit demand bids in section 39.2.2.

489. Manitoba Hydro requests that Module C be revised with the addition of a provision that states all sales of Energy and Ancillary Services in the Midwest ISO energy market from Generation Resources located in Canada and all purchases from the Energy Market by market participants to serve load in Canada shall have a Point of Delivery at the Canada/U.S. border.

iii. Discussion

490. Section 38.2.5.a.ii requires that market participants must operate their resources to follow the Midwest ISO's directions. This provision applies to market participants within the Midwest ISO region and those market participants that supply energy to, through or out of the Midwest ISO region. This provision is reasonable as a basis for the Midwest ISO to direct resources in the event of, for example, emergency procedures, surpluses and shortages. However, we agree with Manitoba Hydro that the provision is written broadly, and needs further definition. Therefore, we direct the Midwest ISO to revise the provision to define the circumstances and examples of actions it will take when setting standards, requirements or providing directions and to limit those directions to those authorized by the TEMT. Inasmuch as generation resources can impact transmission system reliability, adopting Manitoba Hydro's request that external resources be exempt from the Midwest ISO's directions and standards would be detrimental to the Midwest ISO's ability to manage the energy market, and therefore we deny rehearing.

491. With respect to section 38.1.6, we note that these provisions are the subject of a settlement filed on October 5, 2004, and therefore we will address these issues in our order on the settlement.

492. We deny Manitoba Hydro's request for clarification of section 39.2.2. Replacing the current definition, "*attached* to the Transmission System," with "directly attached" does not rectify any conflict between the definition of a load-serving entity and load, as Manitoba Hydro asserts. The definition of Load Serving Entity includes load that is *attached* to the Transmission System,[340] whereas the definition of Load applies to load within the Transmission Provider Region.[341] The definition of the Transmission Provider Region references load *interconnected* to the Transmission System.[342] We do not see any meaningful conflict between these terms, and we do not see that any purpose would be served by changing the definition. More pertinent to Manitoba Hydro's concerns, we agree with Manitoba Hydro's interpretation that it does not serve load in the Transmission Provider Region and therefore is unable to submit a demand bid. As an entity that is unable to transfer operational control of its transmission facilities to the Midwest ISO, Manitoba Hydro's transmission system is not included in the definition of Transmission System.[343] Manitoba Hydro's load therefore cannot be attached to the transmission system in the Transmission Provider Region.

493. We agree with Manitoba Hydro that the definitions associated with External Bilateral Transaction Schedules are confusing, and we direct changes to the definitions as discussed above in our discussion of Module A. Further, we recognize the importance of clear definitions for the purposes of obtaining all permits, licenses and approvals required to participate in the energy markets. We therefore direct the Midwest ISO to insert a provision into Module C that states that all sales of energy and ancillary services into the energy markets from generation resources located in Canada, and all market participants' purchases from the energy markets to serve load in Canada, shall be deemed to have a point of delivery at the Canada/United States border.

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[340] *See* Module A, section 1.171, Original Sheet No. 92.

[341] *See* Module A, section 1.168, Original Sheet No. 91.

[342] *See* Module A, section 1.325, Original Sheet No. 135.

[343] *See* Module A, section 1.328, Original Sheet No. 136 (defining the Transmission System as "transmission facilities owned or controlled by entities that have conveyed operational control to the Transmission Provider . . . .").

h. Attachment W

i. Background

494. The TEMT II Order accepted Attachment W, a Form of Market Participant Agreement, as amended. The Commission found that the proposed Market Participant Agreement, which applicants for market participant status must execute in order to become a market participant, was reasonable, and that it did not unduly burden or discriminate against those parties that seek market participant status.[344]

ii. Requests for Rehearing

495. Joint Cooperatives submit that the TEMT II Order did not recognize or discuss NRECA's protest to Attachment W, and restate NRECA's arguments in their request for rehearing. Joint Cooperatives allege that section 7.0 of the Market Participant Agreement creates an unreasonably broad and vague indemnification obligation in favor of the Midwest ISO, and causes confusion because it seems to be at odds with the terms for indemnification stated elsewhere in the TEMT. Joint Cooperatives argue that section 7.0 suggests that there may be an implied agency relationship that would create indemnification liability, without any definition of what actions might imply that liability, and without any liability limitations of any kind. Joint Cooperatives argue that this risk of undefined, unlimited liability would be unacceptable to a market participant under any standards for risk management and is not found in any similar, market-based industry agreement forms. Further, Joint Cooperatives state that the indemnification section is unnecessary in light of the TEMT provisions on indemnification that are already incorporated into Attachment W by reference. The TEMT provisions, they add, contain liability limitations based on negligent or intentional wrongdoing of the Midwest ISO.

496. AMP-Ohio also protests the indemnification provision contained in section 7.0 of Attachment W because it is too broad. AMP-Ohio contends that any indemnification provision should apply only to the functions covered by the agency agreement.

iii. Discussion

497. We will grant Joint Cooperatives' and AMP-Ohio's requests for rehearing. Joint Cooperatives and AMP-Ohio state correctly that the TEMT II Order did not address arguments in the initial protests regarding Attachment W, and so we will address them here.

[344] TEMT II Order at P 599-606.

498. Section 7.0 of the Market Participant Agreement reads:

> The Market Participant hereby indemnifies the Transmission Provider for any actions taken by any Designated Agent of the Market Participant including, but not limited to, any Scheduling Agent, Metering Data and Management Agent or any other Agent or Market Participant acting on behalf of this Market Participant.[345]

499. We do not understand Joint Cooperatives' allegation that this section suggests that there may be an implied agency relationship that would create indemnification liability. Section 1.68 defines Designated Agent as "[a]ny entity that performs actions or functions required under this Tariff on behalf of the Transmission Provider, an Eligible Customer, the Transmission Customer, an ITC, the Market Participant or a Control Area Operator."[346] Joint Cooperatives may mean to suggest that under section 7.0 of Attachment W, the market participant must be responsible for *any* action of its Designated Agent, whether or not that action takes place within the scope of the agency relationship between the market participant and the Designated Agent.

500. Although we appreciate that it may be appropriate to assign a market participant sole responsibility for the actions of its agent, as section 7.0 of Attachment W seems to propose, we agree with AMP-Ohio and the Joint Cooperatives that it seems unnecessary to include a second liability provision in a Market Participant Agreement that incorporates the entire TEMT, including the TEMT's provisions regarding limitation of liability. We also note that the Midwest ISO has filed to amend the liability and indemnification provisions of its OATT,[347] and that it has promised to amend the TEMT consistent with the results of that proceeding.[348] We therefore direct the Midwest ISO to remove section 7.0 from the Market Participant Agreement, without prejudice to the

[345] Attachment W, section 7.0, Original Sheet No. 1691.

[346] Module A, section 1.68, Original Sheet No. 65.

[347] *See* Midwest Independent Transmission System Operator, Inc. and American Transmission Company LLC, Transmittal Letter, Docket No. ER04-1160-000 (Aug. 30, 2004).

[348] *See* Response of the Midwest Independent Transmission System Operator, Inc. and American Transmission Company LLC at 2, Docket No. ER04-1160-000 (Oct. 5, 2004).

filing of a revised proposal after the proceeding in Docket No. ER04-1160-000 concludes.

501. To ensure that parties to GFAs will not need to execute the Market Participant Agreement on an annual basis, we direct the Midwest ISO to strike references to Schedule 16 and 17 from section 4.0 of Attachment W. As the status of the GFAs in the Midwest ISO change, the schedules that are applicable to them will change accordingly. For example, a tariff customer may have an executed Market Participant Agreement that binds them to pay both Schedule 16 and 17, but, in the following year, select a different option for GFA treatment so that these charges no longer apply. This modification to Attachment W will clarify the TEMT and make it less administratively burdensome to tariff customers by allowing the same Market Participant Agreement to exist through multiple changes in market participant status.

502. Section 4.0 currently states, "The Transmission Provider agrees to provide services to the Market Participant upon a request by an authorized representative of the Market Participant. The Market Participant agrees to take and pay for the requested services in accordance with the provisions of the Tariff and this MP Agreement including, but not limited to, all charges under Schedules 16 and 17 of the Tariff."[349] We direct the Midwest ISO to strike "including, but not limited to, all charges under Schedules 16 and 17 of the Tariff," so that section 4.0 ends after "Agreement." In lieu clarifying the applicable charges in Attachment W, we direct the Midwest ISO to clarify the applicability in Schedules 16 and 17 respective. This clarification should include language stating that GFA parties that chose Option B are required to pay Schedule 16 charges, even though they do not actually receive an allocation of FTRs. In addition, we direct the Midwest ISO to clarify that carved-out GFAs, and GFAs under Option C, do not pay Schedule 16 charges for FTRs. Finally, we require the Midwest ISO to clarify that every tariff customer is required to pay Schedule 17 charges. This is consistent with prior Commission directives in the order addressing the GFAs, [350] and the companion order on the paper hearing and compliance filing.[351]

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[349] *See* Attachment W, Original Sheet No. 1690.

[350] GFA Order at P 293-299.

[351] *Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,235 at P 25-51 (2004).

503. The Commission will also require the Midwest ISO to define the term, “Tariff” in Module A of the TEMT. As a frequently used, capitalized term, it is appropriate that the Midwest ISO define it in Module A. We direct that “Tariff” should be defined to include all Midwest ISO Schedules and Attachments. Therefore, we direct the Midwest ISO to strike the language in section 4.0, clarify the applicability of Schedule 16 and 17 charges, and define “Tariff” through a compliance filing within 60 days.

i. Generator Shortfall Uplift Charge

i. Background

504. The TEMT II Order accepted the Midwest ISO’s proposal to uplift generator costs that exceed the cleared market price, subject to the Midwest ISO making certain modifications. The Commission noted that it has accepted such proposals for other ISOs and RTOs. The Commission explained that without the commitment of these resources whose costs are being uplifted, the bidders in the market may face higher costs as higher-cost resources that can be started up quickly with no minimum running times are committed. The Commission stated that making sure generators recover their costs helps to ensure that there is an adequate source of energy in the market at the lowest cost. To mitigate the level of uplift charges, the Commission required Midwest ISO to make several changes to its proposal. The Commission also stated that the benefits of this provision outweigh the Midwest ISO TO’s concerns about price certainty.

505. Further, the Commission recognized that the allocation methodology in the formula rate is different from what the Commission has approved in some other proceedings; however, the Commission believed that the Midwest ISO’s proposal adequately matches the expected benefits of committing these resources with the costs of committing them. Additionally, the Commission dismissed arguments that self-scheduling entities should be exempt from the uplift stating that all load benefits from the congestion management and ancillary services which are supported by the generators being committed at the lowest cost.

ii. Requests for Rehearing

506. The Midwest ISO TOs request the Commission to clarify how customers will be protected from large charges resulting from the uplift provisions of the TEMT. Cinergy complains that the methodology for calculating the guaranteed payments should be in the filed tariff. Midwest ISO TOs and Cinergy also complain that the formula rate does not provide the customer with enough specificity to allow the customer to know what it will

be paying.[352] The Midwest ISO TOs also state that the proposal is inconsistent with Commission precedent regarding price certainty, noting that in some instances the Commission has denied filings for failure to provide price certainty.[353]

507. The Midwest ISO TOs fault the Commission for relying on FPA section 206 complaint procedures for remedying any higher-than-expected uplift charges. They state that the Midwest ISO will have all the information regarding the basis of the uplift charges so the customer will face great difficulty in supporting an FPA section 206 complaint. They also question whether a complaint can provide relief retroactively.

508. The Midwest ISO TOs suggest requiring the Midwest ISO to submit a compliance filing that addresses price certainty and rate shock issues and institutes a cap on generator uplift charges.

iii. Discussion

509. We deny Midwest ISO TOs' request to require a cap for generator guarantee payments. As the Commission stated in the TEMT II Order, generator guarantee payments benefit customers by allowing the dispatch to be efficient, *i.e.*, the lowest overall cost to the market participants.[354] For example, if real-time conditions change and an expensive generator with a high start-up cost is dispatched for fewer hours than needed to cover start-up, it can back down given the revenue guarantee and the market will benefit from the lower clearing prices (the uplift cost should be considered against those resulting benefits). Otherwise, the generator would have either to raise its energy price or to require an inefficient minimum run time to hedge itself against start-up cost recovery risk, which would raise the overall cost to the market participants. Thus, a cap on the guarantee payments would result in inefficiency. Moreover, the Commission has rejected earlier generator guarantee payment proposals that potentially precluded generators from recovering their costs.[355]

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[352] Midwest ISO TOs Request for Rehearing at 12-13 (quoting *Columbia Gas Transmission Company* v. FERC, 831 F.2d 1135, 1141 (D.C. Cir. 1987)).

[353] *Id.* at 13-14 (citing *ISO New England, Inc.*, 108 FERC ¶ 61,069 at P 25 (2004); *PJM Interconnection, L.L.C.*, 102 FERC ¶ 61,276 at P 2 (2003); *Midwest Independent Transmission System Operator, Inc.*, 101 FERC ¶ 61,221 at P 63 (2002).

[354] TEMT II Order at P 581, 586.

[355] *See id.* at n.346 (citing *New England Power Pool*, 94 FERC ¶ 61,047 (2001)).

510. We disagree with the protesters regarding the formula specificity. The existing formulas in sections 39.3.1.(c) and 40.3.3.(a)(ii) adequately explain the allocation and assessment of the uplift charge. However, we agree with Cinergy that the TEMT does not explain the methodology for calculating the guarantee payments made to generators which are inputs into the formulas. Accordingly, we direct with the Midwest ISO to clarify sections 39.2.9.(f) and 40.2.13 to explain how the guarantee payments are calculated.[356]

511. We find it critical to keep the generator shortfall uplift charges as low as possible, while balancing this against the total cost to the market participants, as discussed above. To the extent other markets initially experienced higher than expected uplift costs, they proposed remedies resulting in lower uplift charges.[357] Building on this experience, we have required the Midwest ISO to modify its generator guarantee payments to avoid experiencing the same problems encountered by other markets. For example, in the TEMT II Order we ordered the Midwest ISO to determine on a daily, rather than hourly, basis whether a generator recovers its costs as a way to minimize instances of higher than expected generator shortfall uplift, as was experienced by ISO-NE. Additionally, to the extent necessary, the Midwest ISO or the IMM, as appropriate, will seek mitigation measures or sanctions to remedy improper seller conduct designed to achieve inflated generator shortfall payments.[358] By adopting best practices of the other markets, we believe the Midwest ISO will be able to minimize uplift charges.

512. Regarding price certainty, we note that the uplift charges incurred in other markets, even when higher than expected, are actually very small compared to the price of energy cleared through the spot market. Given this experience and our expectation that like charges to each Midwest ISO market participant will be very small, we will not at this time require a delay in the market to address the Midwest ISO TOs' concern about price certainty. We will instead require the Midwest ISO to initiate discussions following six months of market experience on the Midwest ISO TOs' concern of price certainty upon expression of interest by market participants.

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[356] Since the formulas in sections 39.3.1.c and 40.3.3.a.ii include the calculation of the guarantee payments in sections 39.2.9.f and 40.2.13 as inputs to the respective formulas, the Midwest ISO is also directed to have the corresponding sections reference each other.

[357] *See* TEMT II Order at 589.

[358] *See* Module E, section 64.2, Original Sheet Nos. 779-80; Module E, section 65.3.1.b, Original Sheet No. 791.

513. While section 206 of the FPA limits the available relief for changes to the formula itself, or market rules, to prospective relief,[359] this limit does not apply to correcting inputs to the formula.[360] Thus, if the Midwest ISO were to miscalculate the inputs to the formula, the Midwest ISO would not be charging the filed rate and would have to remedy this by correcting the inputs. Further, with respect to the formula, the experience with generator uplift charges in other markets is that ISOs and RTOs have refined their proposals over time as issues have arisen in order to minimize the uplift charges and thereby protect market participants.[361] We encourage the Midwest ISO and stakeholders to work together going forward to determine whether it may be possible to refine the generator shortfall uplift formula to lower the uplift charge.

j. Excess Congestion Charge Fund

i. Background

514. The TEMT states that the Midwest ISO will distribute any transmission congestion charges remaining in the excess congestion charge fund to network customers and point-to-point customers based on their charges for network and point-to-point service, regardless of whether these transmission customers hold FTRs for their transmission service.

ii. Requests for Rehearing

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[359] The Commission must establish a refund effective date that is no earlier than 60 days after it receives a complaint or publishes a notice of its intent to open an investigation under section 206 of the FPA, and no later than 5 months after the expiration of that 60-day period. When the proceeding has ended, the Commission may order a public utility to refund, for a period of time subsequent to the refund date, any amounts in excess of what would have been paid under a just and reasonable rate. 18 U.S.C. § 824e(b) (2000).

[360] *See, e.g., UtiliCorp United, Inc. v. City of Harrisonville, Missouri*, 95 FERC ¶ 61,054 at 61,130 n.17, *order on reh'g* 95 FERC ¶ 61,392 (2001); *Appalachian Power Company*, 23 FERC ¶ 61,032 at 61,088 (1983).

[361] *See New England Power Pool*, 97 FERC ¶ 61,338 (2001), *reh'g denied* 98 FERC ¶ 61,299 (2002). *See also New England Power Pool*, 97 FERC ¶ 61,338 (2001), *order on reh'g* 98 FERC ¶ 61,299 (2002) (accepting a revision to an input to the New England Power Pool's generator uplift provision, in order to more accurately identify when generators were (or were not) entitled to uplift payments).

515. Cinergy states that as a vertically integrated utility, it is not invoiced for Network Integration Transmission Service for serving its native load. Cinergy argues that all customers, regardless of whether they are invoiced, incur charges and are entitled to the distribution of any transmission congestion charges remaining in the excess congestion charge fund.

iii. Discussion

516. We agree with Cinergy that all network and point-to-point service customers should share in the distribution of any transmission congestion charges remaining in the excess congestion fund. These customers pay to develop the transmission system and excess transmission congestion charges, representing the usage of the transmission system, should be refunded to those that paid to develop the transmission system. However, since vertically-integrated utilities, like Cinergy, pay for network service to serve their native load, we believe that they already receive the credits to which they are entitled. Accordingly, we reject Cinergy's proposal to modify the tariff language.

k. Miscellaneous Definitions

517. The Midwest TDUs raise a number of definition and interpretation issues for various sections of Module C. We address these issues below and in the table following that lists the issues and our directives to the Midwest ISO by section heading.

Section	As-Filed Language	Issue Identified in Rehearing Request	Required Midwest ISO Action
38.1.6.c.iv	The Midwest ISO will "Develop and send economic base points for each Generation Resource to Market Participants and Control Area Operators based on Offers to the Energy Market."	"Generation Resource" should be broadened to "Resource." See section 40.2.9.a.	We direct the Midwest ISO to revise "Generation Resource" to "Resource."
38.8.3.b.i	"The GFA Responsible Entity shall be responsible for the Transmission Provider's administrative costs associated with accounting for the FTRs under this option as set forth in Schedule 16 of this Tariff."	For the reasons given in Midwest TDUs' May 7, 2004 Protest and their June 26, 2004 Request for Rehearing, it is reasonable that Option B GFAREs not be assigned Schedule 16 costs. That is what the tariff ultimately provides, since Schedule 16 applies charges only to FTR holders, and Option B GFAREs do not hold FTRs. The quoted sentence in	No change required. The GFA Order (at P 294) assigned Schedule 16 costs to Option B GFAs. That is the proceeding in which to raise issues with Schedule 16.

		section 38.8.3.b.i, however, is confusing and should be deleted.	
39.2.2.b.1	"MWh quantity desired to be purchased, with a default of zero (0) MWh."	Although the default should be zero absent contrary instruction, the Midwest ISO should allow market participants to maintain standing orders, either (at the participant's option) resetting their default value to a number other than zero or establishing as a default that the prior day's bid value carries over unless changed.	We direct the Midwest ISO to revise this provision so that standing orders can be accommodated.
39.2.5.a.iii	"DRR Offers must identify the DRR decrement that will provide <u>non-spinning</u> Operating Reserve"	Behind-the-meter generation that qualified as DRR could also supply spinning reserves.	We direct the Midwest ISO to delete "non-spinning."
40.3.3.a.ii	"The Market Participant's Real-Time Revenue Sufficiency Guarantee Charge for that Hour shall equal the product of: (i) the Market Participant's total <u>uncovered Load</u> withdrawn during the Operating Day (in MWh) ...."	"Uncovered Load" is undefined and should be clarified. Does it mean real time Load that differs from the Load served bilaterally or by spot purchases in the day-ahead market?	We direct the Midwest ISO to define "uncovered Load."
40.3.4.c.ii	[Settlement when actual injections exceed the real-time dispatch instruction] **Outside of the Tolerance Band....** the Market Participant shall be penalized by being <u>credited only the product of: (i) forty percent (40%)</u> of the Hourly Ex Post LMP at the applicable Market Participant's Commercial Node; and (ii) the positive difference between the Actual Injections at that Commercial Node and the Tolerance Band upper limit.	The percentage here should be 60 percent. Forty percent is the penalty level for out-of-band injections <u>below</u> the instructed amount. The loss-of-credit penalty for injecting <u>more</u> than instructed is intended to be, and should be, symmetrical, in order to avoid creating an incentive to schedule inaccurately. Symmetry with a 40 percent under-injection penalty requires 60 percent payment for over-injection; that amounts to loss of 40 percent of the market value of the injected energy.	We direct the Midwest ISO to revise (i) to credit the product of 60 percent.
43.2.5.b, second-to-last	"Where the FTR source is unavailable due to scheduled maintenance, settlement conditions	Ambiguous - vary from what? vary how? Is the intent that outages due to	The statement is ambiguous. We direct the Midwest

sentence	may vary."	scheduled maintenance may result in non-nominated counterflow FTR obligation having to financially settle? That would be unreasonable if the outage schedule was reasonable or Midwest ISO-approved.	ISO to delete or revise and explain the meaning.
43.5.3	"A CFTR request cannot distinguish between On-Peak and Off-Peak."	Provision appears within "FTR Allocations for New Service Provision." Its application should be and presumably is limited to that context, but its wording in isolation does not make limitation that clear. Matching FTRs to existing services requires the ability to distinguish diurnally, and compliance with the TEMT II Order requires the ability to distinguish between weekday and week-long restorable CFTRs.	We direct the Midwest ISO to add at the end of the sentence "for New Service."
39.2.4 and 39.2.7	"Virtual Bid Components" and "Virtual Supply Offer" rules.	Midwest ISO should clarify in the tariff whether virtual bids and offers can include steps (i.e., price/quantity pairs), as real ones can.	We direct the Midwest ISO to clarify.
39.3.2.b, 40.2.13.1	"If the Start-Up, No-Load and calculated production costs during the commitment periods for the cleared Day-Ahead Schedules (MW quantities) exceeds the sum of the value..."	Basis for calculating the "production costs" is not clear. Is it based on the offer curve?	We direct the Midwest ISO to define production costs in TEMT.

518. Section 38.1.6.a.vi of the TEMT provides that the Midwest ISO, as Reliability Authority, will receive generator planned outage plans from transmission operators for reliability analysis of the Reliability Authority Area. Midwest TDUs state that generators furnish information directly to the Midwest ISO, as provided in section 38.1.6.a.vii. Midwest TDUs argue that the more important and intended information to be passed to the Midwest ISO should be plans for planned transmission outages, and that the tariff should be edited accordingly.

519. Cinergy in its protest proposes to revise section 38.2.5.e.v to indicate that market participants will use "reasonable" efforts, rather than the current language "best efforts" to provide the Midwest ISO with metered values for settlement. It asserts that "best efforts" raises an ambiguity and there should not be a suggestion that metered obligations could result in significant, unjustified financial impact to market participants. We consider the term "best efforts" appropriate for the task of settling metered values and do not believe the term "best efforts" will lead to significant or unjustified financial impact on market participants and therefore dismiss the request.

520. In their roles as control area operators, transmission owners are responsible for coordinating generator outage plans in their control area with the Midwest ISO, in order to plan system operations. This function requires continual communication of generator plans with the Midwest ISO. For this reason, we deny Midwest TDUs' request for rehearing on this point.

521. Cinergy in its Protest asserts that section 38.2.8 needs to be revised, as indicated in brackets:

> Failure to comply with any of the requirements and/or provisions of this Tariff shall subject a Market Participant to such reasonable charges, penalties, or other remedies or sanctions for non-compliance as may be recommended by the Transmission Provider and [substantiated and] implemented through appropriate Commission proceedings.

522. Cinergy also contends that the imposition of charges, sanctions, penalties, remedies, etc. should be subject to a Commission adjudication process. We believe the provision clearly contemplates Commission adjudication of failures to comply with the tariff that may result in sanctions or penalties. By the requirements of the Commission's regulations, all claims of failure to comply brought before the Commission must be substantiated. Therefore, we see no reason to revise the tariff as Cinergy proposes.

523. Cinergy proposes a number of revisions to sections 38.6 and 38.7. We note that an Balancing Authorities Settlement was filed on October 5, 2004 that addresses the issue of functional responsibilities, including control area and transmission operator responsibilities. We will address tariff revisions pertinent to these issues after we have reviewed and issued an order on the pending settlement.

524. Cinergy requests that section 43.2.5(a)(i) be revised to include the methodology by which the Midwest ISO will determine the measure of the amount of curtailed CFTRs that it can restore. We agree that this provision should be added to this section since CFTR restoration will have a substantial impact on customers, and direct the Midwest ISO to revise its tariff accordingly.

525. Cinergy in its Protest raised a series of issues on which it requests clarification and requests a series of revisions to definitions for which it has not provided an explanation. Since the Commission does not have the information necessary to provide answers nor does it have the basis to determine if the requested revisions would be just and reasonable, we direct the Midwest ISO to respond to these questions.

- **Introduction** Cinergy requests clarification on how 'combined economic value' will be developed.

- <u>Section 38.1.1</u>: **Scope of Services** Cinergy requests clarification in subsection (e) on how a Transmission Owner will be compensated for costs incurred when directed to reschedule a transmission facility outage. On subsection (f), Cinergy requests clarification on whether the Transmission Provider plans to submit for approval a communication plan for Emergencies. On subsection (h), Cinergy requests clarification on how will the Transmission Provider coordinate Curtailment of Load or Load Shedding with neighboring RTOs and/or Control Areas to the Transmission Provider. On subsection (j), Cinergy proposes to replace "Determine" with "Implement and maintain," stating that the Market Participants are responsible for this function.

- <u>Section 38.1.3</u>: **Informational and Reporting Requirements** Cinergy claims that the Market Portal should post the hourly interval LMP calculations.

- <u>Section 38.1.6</u>: **Operational Functions and Responsibilities of the Transmission Provider** Cinergy requests clarification on the meaning of "integrated operational plans" in subsection (f)(ii), the meaning of "balanced Interchange Schedule" in subsection (f)(iv) and a request for clarification on the frequency and intervals for confirmations in subsection (g).

- <u>Section 38.2.1</u>: **Market Participant General Rights and Responsibilities** A Market Participant may participate in all Market Activities. The Market Participant shall settle with the Transmission Provider for all credits and debits associated with these Market Activities. A Market Participant may designate a Scheduling Agent to conduct scheduling activities and/or a MDMA to conduct metering activities on its behalf [and/or a Billing Agent to conduct settlement activities on its behalf.] The Market Participant, however, ultimately remains financially liable for, [delete 'and shall settle'] all such Market Activities with the Transmission Provider. [Proposed revisions shown in brackets.]

- Section 38.2.2: **Market Participant Application and Qualifications** Cinergy requests clarification on subsection (b) that if any entity other than a Control Area is designated as an MDMA, that Control Area must still receive the metered data. On subsection (b)(i), Cinergy requests clarification on whether the tariff will include a form of agency certificate acceptable to the Transmission Provider.

- Section 38.2.3: **Market Participant Applicant Continuing Obligations** Cinergy proposes that the tariff include a definition of Material Adverse Change referenced in subsection (b).

- Section 38.2.5: **Market Participant Obligations** Cinergy proposes that this provision be revised so that Market Participants are required to comply with the principles, guidelines, standards and requirements of control areas, in addition to the Commission, NERC and RROs in subsection(a)(i). In subsection (a)(ii), Cinergy proposes a revision that indicates Market Participants "shall endeavor in good faith" to ensure that offers do not exceed the Capacity of Jointly Owned Generation Resources, and further requests clarification that a Market Participant may not have the legal authority to control or modify the behavior of a non-affiliated Market Participant that jointly owns generation. On subsections (d)(ii), (iii), (iv), (v), and (vi), Cinergy proposes that each section be revised to state that the Market Participant shall "have the systems to permit the Market Participant"to report to the Transmission Provider, to comply with the Transmission Provider requirements, furnish information, respond to Transmission Provider, and to provide requests to the Transmission Provider, and clarifies that this provision goes beyond that which is necessary for communication purposes. On subsection (e) **Metering** Cinergy proposes that that Transmission Provider establish [reasonable] standards in subsection (i). In subsection (iii), Cinergy proposes the following changes, shown in brackets:

  > Where available, a Market Participant [or agent] shall provide the Transmission Provider with Metered data that meets the Transmission Provider's requirements by one of the following means: (a) direct transmission to the Transmission Provider; (b) direct transmission to the Transmission Provider through the Control Area Operator, Transmission Owner or ITC

> within whose area the Load is located; or (c) indirectly through the metering provided by the Control Area Operator, Transmission Owner, or ITC within whose area the Load is located. [The Transmission Provider shall make this data available to the Control Area Operator upon request.]
>
> The Market Participant [or agent] shall also provide its Metered data to the Transmission Owner, Control Area Operator, or ITC within whose area the Load is located to the extent such information is needed to implement the Transmission Provider's system operation and planning functions, to provide billing services to the Market Participant, to allow for data to be verified and agreed to by Transmission Owner, Control Area Operator, or ITC, or to permit the performance of calculations required by the Transmission Provider.

In section 38.2.5, subsection (f), Cinergy requests clarification that a Market Participant can utilize Point-to-Point Transmission Service to deliver to resources located outside of the Transmission Provider Region to a proxy-bus at the electrical boundaries of the Transmission Provider Region. On subsection (h), Cinergy requests clarification in subsection (i) on what Generation Resource(s) does not affect transmission capability or reliability. On subsection (iii) Cinergy requests clarification on the meaning of "documented reasonable expectation."

- <u>Section 38.2.6</u>: **Market Participant Operational Functions and Responsibilities** Cinergy proposes the following revision to subsection (e), as shown in brackets:

> The day prior to the Operating Day, Market Participants that are LSEs or purchase on behalf of LSEs shall perform the following functions:
>
> i. Provide generation commitment to the Transmission Provider;
> ii. Work in conjunction with the Balancing Authorities and Transmission Operators to [plan][delete "implement"] Load Shedding during Emergency conditions.

- <u>Section 39.1.5</u>: **Posting of the Day-Ahead Schedules** Cinergy proposes the provision be revised to state that Control Area Operators have access to the Day-Ahead Schedules for service within its Control Area.

- Section 39.2.7: **Virtual Supply Offer Rules** Cinergy requests clarification on whether the Midwest ISO will be providing specifications for Virtual Bids.

- Section 39.2.8: **External Supply** Cinergy requests the Midwest ISO to include a definition of "Physical Transaction."

- Section 39.3.3: **Payments and Charges for Bilateral Transaction Schedules** Cinergy proposes that the Transmission Usage Charge be *limited to*, rather than *includes* as the current tariff is written, the Cost of Congestion and the Cost of Losses.

- Section 40.1.2: **The RAC Process** Cinergy proposes in subsection (b) the following revision, shown in brackets:

  > After publishing the Day-Ahead Energy Market results [at the close of the Day-Ahead Market], the Transmission Provider will publish its most recent Load Forecast for each Hour of the Operating Day.

  Cinergy also requests clarification that the Notification procedures in subsection (d) will be addressed in the Business Practices Manual.

- Section 40.1.5: **RAC Selection Process** Cinergy requests clarification that the RAC Objective Function does not consider Control Area reserve allocations in performing optimizations.

- Section 40.2.3: **Offer Rules and Obligations for Market Participants in the Real-Time Energy Market** Cinergy proposes to delete the phrase "which shall be based on the actual capability of the Resource to operate on its Offer curve and may not be used to withhold a portion of the Capacity of a Resource from the Real-Time Energy Market, except for Regulation reserves a Resource is providing" from the Hourly Economic Minimum provision and put the phrase in the Hourly Economic Maximum provision. In its response, we direct the Midwest ISO to explain why it proposed to include this phrase only for Hourly Economic Minimum and not for both the Maximum and Minimum.

- Section 40.2.4: **External Demand in the Real-Time Energy Market** Cinergy requests clarification on the meaning of "Dynamic" in the phrase "Dispatchable Dynamic External Bilateral Transaction Schedules."

- Section 40.2.6: **Rules for Bilateral Transaction Schedules in the Real-Time Energy Market** Cinergy proposes the following revision, shown in brackets:

  > Market Participants may submit Bilateral Transaction Schedules up to thirty (30) minutes prior to the [start time of the Bilateral Transaction Schedule][delete “effective hour”] in the Real-Time Energy Market and if so, are subject to Transmission Usage Charges.

  Cinergy indicates the proposed revision is needed to make the section more in line with PJM practices. Cinergy also repeats its request for clarification on the meaning of “Dynamic” in this provision.[362]

- Section 40.3: **Settlement of Real-Time Energy Market** Cinergy requests clarification on the meaning of “timely Settlement” and notes that no criteria are provided to determine the timing procedures for Settlement.

- Section 40.3.2: **APNode Weighting** Cinergy proposes the following revision, shown in brackets:

  > Aggregate Price Nodes (APNodes) are the weighted average of a set of hourly PNodes which include Load Zones, Interfaces and Hubs. The set of Commercial Nodes and weights for Hubs are pre-determined and published[; provided, however, that such Commercial Nodes and weights for Hubs may be modified by the Transmission Provider to the extent justified by the Market Participant(s).] The set of Commercial Nodes for Load Zones are those PNodes within the Zone that have Load settled at the Zonal LMP. The weights for each Node in the Load Zone are equal to the corresponding State Estimator calculated volume (MW).

- Section 41: **Settlement Statements and Invoices** Cinergy proposes to delete “Invoices” from the section title and states the Midwest ISO must incorporate into the tariff sufficient detail to allow verification of the invoiced amounts.

- Section 41.1: **Settlement Statements** Cinergy asserts the tariff needs to

[362] Cinergy also repeats this clarification request for section 40.2.8

address the re-settlement process, including but not limited to the interval for such re-settlement periods.

- Section 41.2: **Confirmation of Settlement Statements** Cinergy proposes the following revision, shown in brackets:

  > It is the responsibility of each Market Participant to notify the Transmission Provider if it fails to receive Settlement Statements [delete the following: on the date specified for issuance of such Settlement statement. Each Market Participant shall be deemed to have received its Settlement Statement on the dates specified, unless it notifies the Transmission Provider to the contrary] If the Transmission Provider receives notice that a Settlement Statement has not been received, it will make reasonable attempts to provide the Settlement Statement to such Market Participant(s). The Settlement schedule will not be modified for a Market Participant's failure to notify the Transmission Provider of a missing Settlement Statement.

- Section 43.2.3: **Registration of FTR Receipt Points As Control Areas** Cinergy requests clarification as to whether, other than the conditions in this section, there are conditions under which the default will not be enforced.

- Section 43.2.4: **Nomination and Allocation of Candidate FTRs** Cinergy proposes to add Firm Point-to-Point Transmission Service as a service that is allocated FTRs and asserts that this section should reference the restoration procedures in section 43.2.5.

- Section 43.2.5: **Transition Process for Restoration of Curtailed FTRs** On subsection (d), Cinergy requests clarification on whether the Midwest ISO will include redirects of point-to-point service in calculating the scheduling factor, and clarification on the meaning of "scheduling factor."

- Section 43.5.3: **Granting FTRs in Pairs** Cinergy explains that subsection (c) states that CFTRs are split into two requests, yet the provision does not specify the two requests and requests clarification.

- Section 43.5.4: **FTR Pre-emption** Cinergy proposes in subsection (e) the following revisions, shown in brackets: "**Renewal:** [Delete "Rollovers are restudied and] CFTRS [are] awarded [pursuant to section 43.2.4] for the next annual FTR re-allocation period." Cinergy explains that rollovers are inappropriate for FTRs.

- Section 44.2.4: **Other Responsibilities** Cinergy proposes revisions as indicated in brackets:

  > The Transmission Provider will [delete " properly utilize an optimization process program to"] determine the set of Winning FTR Bids for each auction [as per section 44.5.1] and calculate the FTR Market Clearing Price of all FTRs at the conclusion of the auction [delete "in the manner described in this Tariff"].

  Cinergy requests that the Midwest ISO clarify what is being optimized in the optimization process program, or delete the language.

- Section 47: **Development of Auction Revenue Rights** Cinergy states the Transmission Provider should set forth a set date for implementing a plan and not "at a future date."

K. Seams Issues

1. Implementing the TEMT in the Midwest ISO Footprint

a. Background

526. Despite the acknowledged challenges of incorporating the Otter Tail control area into the energy markets, the Commission held in the TEMT II Order that Otter Tail belongs under the entire TEMT and, therefore, denied its request for exemption from Module C of the TEMT. The Commission noted that the Midwest ISO has offered nothing to suggest that Otter Tail cannot successfully be incorporated into the energy markets by March 1, 2005. The Commission also explained that exempting an entire control area from the energy markets would require a system of physical rights based on first-come, first-serve be applied to service over the transmission facilities in the control area. Likewise, congestion would have to be resolved through cost-based, rather than market, services. The Commission expressed concern that if Otter Tail were exempt from the energy markets, the Midwest ISO, as the transmission provider for the Otter Tail system, would have to create and administer a separate transmission tariff for the Otter Tail control area, but neither Otter Tail nor the Midwest ISO submitted such a tariff for Commission review.

527. The Commission also noted that seams must be resolved, particularly throughout the MAPP region, whether or not Otter Tail is in the market, and that seams should be resolved sooner rather than later.[363] Otter Tail had not demonstrated that exemption from the energy markets will accelerate the process of seams resolution. In fact, the Commission stated that an exemption for Otter Tail, with only an obligation to file a progress report a year after the markets start, arguably would remove the incentive for any of the affected parties, especially those non-jurisdictional entities that prefer to remain out of the market, to timely resolve the seams issues. The Commission also observed that other entities in the region that expressed a preference for the markets would be denied full participation in the markets if we granted Otter Tail's request for an exemption from the energy markets.

528. The Commission agreed with the Midwest ISO that the absence of seams agreements should not impede market start-up, but cautioned that the markets cannot start without the Midwest ISO having at least a specific, transparent plan for how it will handle the interface of multiple transmission tariffs and market-to-non-market seams.[364] The Commission encouraged the parties to use the PJM-Midwest ISO JOA as a model for seams agreements that must be filed with the Commission.

529. Finally, the Commission also found that two of the concerns Otter Tail raised – joint ownership of generation and North Dakota Export (NDEX) redispatch rules – can be accounted for in the market rules. The Commission directed the Midwest ISO to make the clarifications Otter Tail requested. While Otter Tail suggested that the Midwest ISO would not be able to perform optimal dispatch and congestion management within its control area, the TEMT II Order stated that some centralized redispatch is better (more efficient) than none at all.

b. Requests for Rehearing

530. Otter Tail and Montana-Dakota reiterate that the Commission should give them an exemption until seams agreements are resolved or explain how congestion management, effective centralized dispatch and FTR allocation will work if seams agreements are not resolved. The South Dakota Commission agrees with the arguments of Otter Tail and Montana-Dakota and asks the Commission to either grant an exemption for Otter Tail and Montana-Dakota or, at a minimum, assure that they will be held harmless until all

[363] *See* TEMT II Order at P 619.

[364] *See id.* at P 639.

material issues can be resolved. Otherwise, the South Dakota Commission states the only option would be for Otter Tail and Montana-Dakota to withdraw from the Midwest ISO entirely.

531. Specifically, Otter Tail and Montana-Dakota state that the Commission failed to address Otter Tail's argument that the Midwest ISO does not control sufficient generation and transmission in the Otter Tail control area.[365] Otter Tail states that this insufficient control will greatly hinder effective management of congestion and centralized dispatch resulting in phantom congestion in Otter Tail's control area unless seams agreements are developed.[366]

532. Moreover, Otter Tail and Montana-Dakota state that the Commission failed to respond to Otter Tail's argument that FTRs can not be allocated to the Otter Tail control area because transmission rights in the NDEX region are unclear.[367] The NDEX region was operated as a single system without clearly defined transmission rights. Otter Tail contends that the Commission has not allowed LMP congestion management systems to be put in place until FTR issues have been resolved.[368]

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[365] Otter Tail states that the peak generation in its control area is 1,500 megawatts and the peak load is about 2,100 megawatts. Otter Tail also states that less than 300 megawatts of its generation is under the control of the Midwest ISO because the other 405 megawatts of its generation involves units jointly owned with entities that are not in the Midwest ISO.

[366] Otter Tail contends that phantom congestion is likely because of uncertainties associated with scheduled flows by non-Midwest ISO members on non-Midwest ISO transmission facilities that are connected with Midwest ISO transmission facilities. These non-Midwest ISO members do not provide schedules to the Midwest ISO, necessitating Midwest ISO to estimate their flows.

[367] Otter Tail suggests that the Commission erred by suggesting that other parties in the Otter Tail control area would not be able to participate in the energy markets if Otter Tail received an exemption because Otter Tail affirms that it will accommodate Xcel and Great River Energy. Otter Tail cites its Protest at 7 n.9 (May 7, 2004).

[368] Otter Tail Request for Rehearing at 16 n.37 (citing *Pennsylvania-New Jersey-Maryland Interconnection*, 81 FERC ¶ 61,257 at Ordering Paragraph (Q) (1997)).

533. Otter Tail and Montana-Dakota also claim that the Commission erred by denying the exemption for Otter Tail, in part, on the difficulty of exempting the Otter Tail control area and that exempting Otter Tail would require a new tariff. Otter Tail states that the Midwest ISO would merely have to provide transmission services to Otter Tail in the same manner that it has done since 2002, making seams agreements unnecessary. Additionally, Otter Tail states that even if another tariff is necessary, the Midwest ISO has experience operating more than one tariff so an exemption for Otter Tail should not cause any difficulty for the Midwest ISO.[369] Montana-Dakota adds that special procedures should be included in the existing Midwest ISO OATT, as necessary, to accommodate an exemption.

534. Otter Tail claims that the Commission's assertion that seams with non-Midwest ISO members must be resolved whether or not the Otter Tail control area is exempt from the TEMT, is unsupported. Otter Tail states that if it were exempted from the TEMT the seam would be between the Midwest ISO and Otter Tail and since Otter Tail is a Midwest ISO member, the seam would not present a problem. Otter Tail also explains that the Midwest ISO has accomplished little to date regarding the negotiation of seams agreements and Otter Tail believes these seams will not be resolved by the time of market start-up.

535. Montana-Dakota and Midwest TDUs claim that it is not reasonable for the Midwest ISO to unilaterally determine how the seams are to be addressed. Rather, the fair way of dealing with seams is to have parties on both sides of the seams agree how to deal with the issues involving market-to-non-market seams. Montana-Dakota notes that many of the other entities with Midwest ISO seams are non-jurisdictional so the Midwest ISO can not dictate the management of that seam.

536. Midwest TDUs also argue that Commission precedent highlights the importance of seams agreements.[370] Since the Commission required Southwest Power Pool (SPP) to file a seams agreement prior to becoming an RTO, Midwest TDUs and Joint Cooperatives find it hard to see how it is less critical for Midwest ISO's successful

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[369] The Midwest ISO currently operates two other tariffs in addition to its own involving Manitoba Hydro and MAPP.

[370] Midwest TDUs Request for Rehearing at n.8 (citing *Alliance Companies, et al.*, 100 FERC ¶ 61,137, PP 48, 53 (2002); *Midwest Independent Transmission System Operator, Inc., and PJM Interconnection, L.L.C.*, 106 FERC ¶ 61,251 (2004)).

operation of its markets.[371] Midwest TDUs and Joint Cooperatives note that the Midwest ISO requested the rejection of SPP's unilaterally-filed unexecuted seams agreement.[372] Midwest TDUs add that given the complexity of the issues involving market-to-non-market seams, the Commission must make seams agreements a prerequisite for market start-up or else give them an exemption from the market.[373]

537. Otter Tail also complains that the Commission did not address Otter Tail's argument that it is unlawful to impose charges on Otter Tail associated with non-Midwest ISO load within the Otter Tail control area because Otter Tail is not taking any services from the Midwest ISO with respect to such non-Midwest ISO load.[374] In support of its position, Otter Tail references a recent Commission order that Otter Tail suggests precludes an ISO from applying tariff provisions to facilities that have not been transferred to the operational control of the ISO, despite the physical location of the facilities in the ISO region.[375] Otter Tail states that *CAISO* is applicable to the Otter Tail control area because the Otter Tail control area includes facilities that are not Commission-jurisdictional and that have not been turned over to the Midwest ISO's functional control. Similarly, Midwest TDUs assert that the Midwest ISO lacks authority, including rate authority, with respect to transmission services provided by and over the facilities of non-members of the Midwest ISO because the Midwest ISO's authority is limited to the authority granted by the Midwest ISO members and Midwest

[371] *Id.* at n.9 (citing *Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110 at P 63 (2004)).

[372] *Id.* at 13 (citing Motion to Intervene, Motion to Reject Compliance Filing, Protest and Request for Hearing of the Midwest Independent Transmission System Operator, Inc., Docket No. ER04-1096 (Aug. 23, 2004).

[373] Midwest TDUs contend that rushing to initiate markets without seams agreements could cause financial harm and harm to reliability. *Id.* at 11 (citing *Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052 at P 36 (2004)).

[374] The Minnesota Commission concurs that it is not reasonable to charge Otter Tail for costs associated with the load of non-market entities. *See* Letter from the Minnesota Department of Commerce to the Federal Energy Regulatory Commission at 2, Docket No. ER04-691-000 (Sept. 14, 2004).

[375] Otter Tail Request for Rehearing at 25 (citing *California Independent System Operator, Inc.*, 107 FERC ¶ 61,152 (2004) (*CAISO*)).

ISO members may not give control over facilities owned by non-members. The Midwest TDUs request that the Commission clarify that the Midwest ISO does not have authority under the TEMT to exercise control over transmission facilities of non-members.

c. Discussion

538. We deny the request for rehearing to exempt Otter Tail and Montana-Dakota from the Midwest ISO energy markets. While we recognize the challenges of incorporating them into the Midwest ISO energy markets, Otter Tail and Montana-Dakota are, as explained above, customers under a tariff which has been revised under section 205 of the FPA. Because the Commission has found the revised Midwest ISO tariff to be just and reasonable, Otter Tail and Montana-Dakota, like all customers under the revised Midwest ISO tariff, are bound by its terms.

539. Moreover, seams would need to be addressed regardless of whether Otter Tail is in the energy markets. Otter Tail dismisses the seam that would occur if Otter Tail was exempt from the energy markets as no problem to the Midwest ISO because it is between the Midwest ISO and a Midwest ISO member. Nonetheless, a market-to-non-market seam would be present even if Otter Tail is exempt from the energy market and the seam still must be resolved.

540. Further, contrary to the assertions of Otter Tail and Montana-Dakota, it would require more than just simple changes to the Midwest ISO's TEMT to recognize their exemption from the energy market.[376] Otter Tail and Montana-Dakota appear to recognize that another tariff or special procedures would be necessary, but they have not submitted the additional tariff or special procedures for Commission review. Thus, the additional tariff or special procedures would likely need to be substantial because, as the Commission explained in the TEMT II Order, LMP inextricably intertwines the day-ahead and real-time markets and their associated congestion management system with the scheduling and provision of transmission service. The removal of a control area from the energy markets means that the transmission and generation facilities in the control area would not be modeled in the LMP system (except for their indirect impacts on other facilities) and that, therefore, a system of physical rights based on a first come, first-serve paradigm would have to be applied to service over those transmission facilities. Likewise, congestion would have to be resolved via TLRs, and imbalances and ancillary services would have to be resolved through cost-based services. Their apparent solution

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[376] In Otter Tail's initial protest, Otter Tail presented a one-page attachment to be included in the TEMT to recognize an energy market exemption. *See* Otter Tail Protest at Exhibit 5 (May 7, 2004).

of receiving service under the current tariff would require the maintenance, in fact the refiling, of a physical rights tariff in addition to the TEMT.

541. Further, as we have explained above, the TEMT allows Otter Tail and Montana-Dakota to choose whether any or all of their resources may self-schedule to meet their respective loads. Only the portion of those units designated by a market participant as Network Resources are committed to the Midwest ISO markets. Thus, Otter Tail and Montana-Dakota already have the ability to self-schedule all of their resources and keep all of their resources out from under the Midwest ISO's control. Therefore, there is no need for them to be exempt from this portion of the tariff.

542. Additionally, with respect to Otter Tail's GFA concerns, the Commission has already clarified the rights in Otter Tail's GFAs to facilitate the allocation of FTRs to the Otter Tail control area in the GFA Order. Moreover, we clarify that the load of the other party to the GFA is subject to the Midwest ISO charges to the extent it receives transmission service over Otter Tail's facilities controlled by the Midwest ISO.[377] Otter Tail explains that in *CAISO* the Commission determined that the CAISO did not have authority to impose costs on Pacific Gas & Electric Company associated with transmission service transactions over facilities within the CAISO control area but outside of the CAISO's operational control. However, *CAISO* is distinguishable because it does not deal with contractual rights to transmission service over non-jurisdictional, non-member facilities in the footprint as is the case here with Otter Tail's GFAs.[378]

543. We again dismiss Otter Tail's concerns regarding joint ownership of generation and NDEX redispatch rules since these issues can be accounted for in the market rules. We believe it would be easier for the Midwest ISO to accommodate certain exemptions to its economic dispatch rules than it would be to construct an entirely new tariff to facilitate an exemption for Otter Tail and Montana-Dakota.

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[377] In its initial protest, Otter Tail states that the issue of Otter Tail being assessed costs by the Midwest ISO for non-Midwest ISO loads in the Otter Tail control area arises because the Midwest ISO is treating certain Integrated Transmission Agreements as GFAs. *Id.* at 14.

[378] With respect to the GFAs, we also clarify that since Otter Tail transferred its rights under the GFAs to Midwest ISO, the Midwest ISO has the same rights to non-members transmission systems that Otter Tail had. Nevertheless, Otter Tail's transmission over a non-member's transmission system to serve Otter Tail load does not make the other transmission owner's load subject to Midwest ISO charges.

544. Lastly, the Commission would be reluctant to grant an exemption because Otter Tail and Montana-Dakota's concerns about market-to-non-market seams may have already been resolved. In the transmittal letter to its October 5, 2004 compliance filing, the Midwest ISO states that it has reached an agreement in principle with the non-Midwest ISO members of MAPP on the most important seams issues and the Midwest ISO expects an agreement will be finalized in time for a December 1, 2004 filing.[379] According to the Midwest ISO, the parties have met several times over the last six months to develop a Seams Operating Agreement (SOA), patterned after the Midwest ISO's Joint Operating Agreement with PJM (Midwest ISO-PJM JOA).[380]

2. Midwest ISO/PJM Joint and Common Market

a. Requests for Rehearing

545. WEPCO claims that although the TEMT II Order directed Midwest ISO to move the proposed closing time for the day-ahead market from 0900 EST to 1100 EST,[381] the Midwest ISO should have been directed to move the closing time to 1200 hours to coincide with PJM's closing time. Additionally, WEPCO renews its request for the Commission to direct the Midwest ISO to use either Eastern or Central Prevailing Time as opposed to Eastern Standard Time. WEPCO comments that the Midwest ISO, which is located in central Indiana, does not recognize Daylight Savings Time and therefore causes confusion, especially during the period from April to October when most of the country uses Daylight Savings Time. WEPCO also states that given the fact that the Midwest ISO will be required to work with PJM to develop a joint, common seamless market, the Commission should take action to avoid the unnecessary creation of a seam as significant as divergent closing times in the two markets.

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[379] Since all issues have not yet been settled, the Midwest ISO commits to filing a status report not later than December 1, 2004, if the parties do not have a final agreement on that date.

[380] The SOA, structured as an agreement between the Midwest ISO and MAPPCOR (the contractor that administers the MAPP Restated Agreement), recognizes that Reliability Coordination is already provided under an existing agreement between the Midwest ISO and MAPPCOR and assures that MAPPCOR will continue to transfer data to the Midwest ISO.

[381] *See* TEMT II Order at P 522.

b. Discussion

546. We will deny rehearing on the issue of closing time for the Day 2 markets. In the TEMT II Order, the Commission directed the Midwest ISO to change its proposed closing time for the day-ahead markets to 1100 EST.[382] This decision was consistent with comments received from stakeholders and Midwest ISO regarding the day-ahead markets deadline. WEPCO has offered no evidence to suggest that any harm will be done by Midwest ISO remaining on Eastern Standard Time. However, as Midwest ISO and PJM renew their efforts on the joint and common market, we expect to see any timing differences minimized or eliminated in that market.

L. Business Practice Manuals and Compliance Procedures

1. Business Practice Manuals

a. Background

547. In the TEMT II Order, the Commission said that the Business Practice Manuals should not take precedence over the TEMT. We declined to require a section 205 filing of the Business Practices Manuals because, while implicating our jurisdiction, they mostly involve general operating procedures. We did require the Midwest ISO to revise the TEMT and any agreement it has on file with the Commission to the extent that they define rates or terms and conditions of service by reference to the Business Practice Manuals. Any reference to the specific rates, terms and conditions, must be set forth in the TEMT and in rate schedules as well.[383]

b. Request for Rehearing

548. Parties raise a number of concerns about various provisions or details that are (or are to be) included in the Business Practices Manuals, but not in the tariff. As discussed below, these provisions range from criteria for system reliability (including SSRs), LMP calculation, metering, emergency procedures, must-offer requirements, timelines for submission of invoices, to billing dispute resolution. In one case, the parties ask the Commission to require the Midwest ISO provide additional detail in the Business Practice Manuals as well.

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[382] *Id.* at P 522.

[383] *See id.* at P 658.

549. Midwest ISO TOs reiterate their protest that the general tariff provisions in sections 38.2.2.f, 38.2.5 and 38.2.5.d of the TEMT grant broad authority to the Midwest ISO and that such authority should be constrained by tariff provisions that state explicitly what it is that the Midwest ISO can order, and under what circumstances.[384] Midwest ISO TOs say that the Commission should constrain the Midwest ISO's proposed broad authority to take or direct any action based on unfiled business practices. Section 38.2.5 states that a market participant shall "comply with the procedures established for operation by the Transmission Provider." Furthermore, "[e]ach Market Participant shall operate, or shall cause to be operated, any Resources owned or controlled by such entity within the Transmission Provider Region or otherwise supplying Energy to, through, or out of, the Transmission Provider Region in a manner consistent with the standards, requirements, or directions of the Transmission Provider." In addition, section 38.2.5.d orders a market participant that is a load-serving entity to "(a) respond to Transmission Provider directives for Load management steps via Control Area Operator communication; and (b) respond to other Transmission Provider directives, such as those required during Emergency operations." Section 38.2.2.f states that market participants must meet "all of the requirements established by the Transmission Provider" without defining those requirements. Midwest ISO TOs say that these sections could be construed to give the Midwest ISO virtually limitless authority to direct the actions of generators and load-serving entities, and to impose requirements that are not in the TEMT. They say that the Commission should require the Midwest ISO to specify through tariff language exactly what is required. They argue that such action is essential to proper administration of the TEMT, and also to limit disincentives to parties becoming market participants.

550. Cinergy notes that with respect to system reliability, section 38.2.7.b states that the Midwest ISO will determine whether a generation resource is necessary for system reliability based on the criteria set forth in the Business Practice Manuals. Cinergy says that such criteria (including significant details such as the technical parameters for SSR designation) should be included in the TEMT and subject to notice and comment and the Commission's approval. At the very least, the relevant information should actually be set forth in the Business Practice Manuals. Currently, section 4.15 of the draft Business Practice Manual for day-ahead energy market lacks the necessary detail to provide market participants an understanding as to how and when the SSR provisions may be applied to them. Without this information, Cinergy argues that the Commission cannot determine that the Midwest ISO's SSR provisions are just and reasonable. Cinergy concludes that the Midwest ISO should be required to incorporate such criteria into the

[384] Cinergy also protests section 38.2.2.f for the same reasons.

tariff in a compliance filing, because the criteria will define terms and conditions of service, including the parties to whom the SRR provisions will apply.

551. Cinergy states that the formula for calculating the LMPs is in the Business Practice Manuals, but that it should be included in the tariff.

552. Cinergy asserts that the Emergency procedures should be included in the tariff rather than in the Business Practice Manuals. Section 1.80 defines an Emergency as: (1) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm Load, equipment damage, or tripping of system elements that could adversely affect the reliability of any electric system or the safety of persons or property; (2) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (3) a condition that requires implementation of Emergency procedures as defined in this Tariff and the Business Practices Manuals. Cinergy asserts the phrase "and the Business Practice Manuals" should be deleted and that the Emergency procedures should be included in the tariff instead.

553. With respect to metering, Cinergy says that the metering standards are not clearly stated in the tariff. It is concerned that the metering standards set forth in the Business Practice Manuals may impose substantive metering obligations on market participants that may have significant costs without any corresponding requirement to demonstrate that high costs are warranted. Any metering standards potentially having such financial impact(s) on market participants must be included in the filed tariff and not simply in the Business Practice Manuals. A final version of the Business Practice Manuals is not available for review. Cinergy argues that the metering provisions are not just and reasonable without being included in the tariff. It advocates that the Commission require the Midwest ISO to propose, for inclusion in the tariff, the metering standards to be extended to market participants, to the extent that such provisions will establish responsibility for the costs associated with metering obligations, and other terms and conditions of service. Cinergy also asserts that section 38.2.2.b[385] should be revised to only refer to the tariff to the extent the provisions relate to costs, rates, terms and conditions, or any provisions that seek to impose substantive obligations on entities.

[385] Section 38.2.2.b requires the Market Participant to demonstrate to the satisfaction of the Transmission Provider that it complies with all applicable metering, data storage and transmission, and other reliability, operation, planning and accounting standards and requirements for operating in the Transmission Provider Region as specified in the Business Practices Manual and tariff.

554. Cinergy requests clarification on provisions in sections 44.2.1 and 45.2.1 that state auction rules and procedures will be implemented consistent with procedures in the Business Practices Manual. Cinergy states the Business Practice Manuals should implement procedures consistent with the tariff, and not vice versa.

555. Cinergy states that any significant provisions set forth in the Energy Markets Billing Dispute Resolution Manual, referenced in section 12.1, need to be included in the tariff. The Midwest ISO has proposed that these provisions be included in Business Practice Manuals and that they be posted on the Midwest ISO website. Cinergy also argues that the Commission should direct the Midwest ISO to incorporate into the tariff the timeframes for the submission of invoices instead of putting those timelines in the Business Practice Manuals.

556. Midwest TDUs state that the current interim must-offer requirement needs additional details. In particular, they assert that references to the business practices manuals in the current one-paragraph must-offer requirement are key areas of service that need to be filed in the tariff. Midwest TDUs cite the eight-page must-offer obligation in the CAISO tariff, where the details have been the subject of substantial litigation.

c. Discussion

557. Rates or terms and conditions necessary to effectuate service should be included in the TEMT. The Business Practices Manual should include information, guidelines, business rules and processes established for the operation and administration of the Midwest ISO markets. Our standard for including items in the tariff is based on whether the provisions affect rates and services significantly, that they are realistically susceptible of speculation, and that are not so generally understood as to render recitation superfluous, as we stated in the TEMT II Order.[386]

558. We agree with Midwest ISO TOs that section 38.2.2.f is overly broad, and direct the Midwest ISO to file tariff provisions specifying the requirements it will establish for entities to qualify as a market participant, as well as an explanation justifying its criteria. With regard to section 38.2.5, we have already required the Midwest ISO to further define the overly broad requirements of section 38.2.5.a.ii relating to the standards, requirements and directions of the Midwest ISO for resource operation. We will further require that the Midwest ISO specify, in the tariff, the procedures it establishes for operation and compliance by market participants, as provided in section 38.2.5.a.i. Finally, with respect to section 38.2.5.d, we agree that “other Transmission Provider

[386] *See* TEMT II Order at P 656.

directives" is overly broad, and direct the Midwest ISO define the directives for which it is requiring compliance in its tariff.

559. With respect to the criteria to determine if a Generation Resource or Synchronous Condenser Unit are needed for reliability in section 38.2.7.b, we note that the Midwest ISO will post the criteria on its website. We expect that this posting of criteria will give parties sufficient information to evaluate whether the SSR provisions would apply to them. While Cinergy raises concerns regarding whether the SSR provisions are just and reasonable, we believe we have addressed this concern through our requirement that the Midwest ISO file negotiated SSR agreements with us, as well as cost recovery information, in section 205 filings. The record in these proceedings will be sufficient for our purposes in determining if negotiated SSR arrangements, including the SSR provisions themselves, are just and reasonable. For this reason, we deny rehearing.

560. Regarding the LMP calculation, we note that other ISOs and RTOs have the LMP formula in their tariffs.[387] The Commission's regulations require that any practices that directly affect rates should be included in the tariff.[388] Since the formulas calculating LMP directly affect the price of energy paid by market participants, we agree with Cinergy that Midwest ISO should reflect the LMP formulas in the tariff.

561. Inasmuch as emergency procedures relate to the terms and conditions of service during emergencies, we agree with Cinergy that the proposed procedures are significant and therefore direct the Midwest ISO to delete the phrase "and the Business Practice Manuals" from section 1.80 and to specify in the tariff any conditions that require emergency procedures. As for Cinergy's concerns with respect to metering standards, we agree that the standards have cost implications, and therefore should be included in the TEMT tariff. Therefore, we direct the Midwest ISO to file tariff sheets detailing its metering standards that have implications for cost responsibility, as well as implications for terms and conditions of service. We agree with Cinergy, that the requirements of section 38.2.2.b are terms of service, in the sense that they are requirements to qualify as a market participant. These requirements should be included in the tariff and therefore

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[387] *See, e.g.*, New York Independent System Operator Market Administration and Control Area Services Tariff, Attachment B, section I and New York Independent System Operator OATT, Attachment J.

[388] *See* 18 C.F.R. § 35.1 (2004) ("Every public utility shall file with the Commission and post . . . full and complete rate schedules, as defined in § 35.2(b), clearly and specifically setting forth all rates and charges for any transmission or sale of electric energy subject to the jurisdiction of this Commission . . . .").

we direct the Midwest ISO to revise this provision accordingly. However, Cinergy has not provided any evidence that the provisions set forth in the Billing Dispute Resolution Manual currently in the Business Practice Manuals meet our standards for inclusion in the tariff, and accordingly we deny rehearing on this issue.

562. We deny Cinergy's request to direct the Midwest ISO to file their invoicing schedules in the tariff. The Commission previously directed the Midwest ISO to clarify its invoicing procedures through a compliance filing.[389] The Commission also noted that the Midwest ISO must make the Business Practice Manuals available for public inspection on a permanent basis.[390] The compliance filing proceeding is the appropriate forum to determine whether or not the Midwest ISO complied with Commission directives on invoicing.

563. With respect to Cinergy's arguments on sections 44.2.1 and 45.2.1, as we stated in the TEMT II Order, the tariff must include provisions that define rates, terms and conditions of service.[391] Sections 44.2.1 and 45.2.1 state that the Midwest ISO will develop and use auction rules and procedures as specified in those sections of the tariff, and that implementation will be based on procedures in the Business Practices Manual. To the extent that auction rules are included in the tariff and only the implementation procedures are specified in the Business Practices Manual, these provisions meet our standards since the relevant terms of service are included in the tariff. Therefore, we dismiss rehearing on this issue.

564. We grant the Midwest TDUs' request for clarity on the details of the must-offer requirement. We direct the Midwest ISO to clarify that submission of offers to comply with the must-offer requirement must comply with the offer requirements specified in Module C for the day-ahead market and the RAC process. However, we do not direct the Midwest ISO to file in the tariff its Business Practice Manuals procedures related to the must-offer requirement because they mostly involve general operating procedures. This is consistent with our decision in the TEMT II Order where we required the Midwest ISO to make the documents permanently available for public inspection, but did not require them to file the Business Practice Manuals.[392]

[389] TEMT II Order at P 473.

[390] *Id.* at P 658.

[391] *See id.* at P658.

[392] *Id.*

2. Compliance Procedures

565. This order directs the Midwest ISO to make a variety of compliance filings to further prepare for the March 1, 2005 energy market start-up date. The IMM is also required to make various filings. Except as otherwise specified in the body of this order, these filings shall be due 60 days from the date of this order.

The Commission orders:

(A) The requests for rehearing of the TEMT II Order are hereby granted, granted in part and denied in part, or denied as discussed in the body of this order.

(B) The Midwest ISO is directed to make compliance filings as specified in the body of this order.

(C) The motions to intervene of Illinois Power, Large Public Power Council and South Dakota Commission are hereby granted.

(D) Montana-Dakota and Otter Tail's motions for stay of the TEMT II Order are hereby denied.

(E) WUMS Load-Serving Entities' motion for expedited action is granted by issuance of this order.

By the Commission. Commissioner Kelliher dissenting in part with a separate statement attached.

(S E A L)

Linda Mitry,
Deputy Secretary.

Appendix A

Parties Filing Requests for Rehearing or Clarification

Ameren – Ameren Services Company
AMP-Ohio – American Municipal Power-Ohio, Inc.
Cinergy – Cinergy Services, Inc.
Coalition MTC – Coalition of Midwest Transmission Customers
Constellation – Constellation Power Source, Inc. and Constellation NewEnergy, Inc.
Consumers – Consumers Energy Company
Detroit Edison – Detroit Edison Company
Dynegy – Dynegy Power Marketing, Inc. and Dynegy Midwest Generation, Inc.
Exelon – Exelon Corporation
FirstEnergy – FirstEnergy Service Company
Illinois Power – Illinois Power Company
IMM – Potomac Economics Ltd.
Joint Cooperatives – National Rural Electric Cooperative Association, Associated Electric Cooperative, Inc., Basin Electric Power Cooperative, Central Iowa Power Cooperative, Corn Belt Power Cooperative, Dairyland Power Cooperative, East Kentucky Power Cooperative, Inc., Hoosier Energy Rural Electric Cooperative, Inc., Minnkota Power Cooperative, Inc. and Southern Illinois Power Cooperative
LG&E – LG&E Energy LLC
Manitoba Hydro
Midwest ISO TOs – Ameren Services Company, as agent for Union Electric Company d/b/a AmerenUE, Central Illinois Public Service Company d/b/a AmerenCIPS, and Central Illinois Light Co. d/b/a AmerenCilco; Aquila, Inc. d/b/a Aquila Networks (f/k/a Utilicorp United, Inc.); City Water, Light & Power (Springfield, Illinois); Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; LG&E Energy Corporation (for Louisville Gas and Electric Co. and Kentucky Utilities Co.); Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company and Northern States Power Company (Wisconsin), subsidiaries of Xcel Energy, Inc.; Northwestern Wisconsin Electric Company; Otter Tail Corporation d/b/a Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); and Wabash Valley Power Association, Inc.
Midwest Municipal Transmission Group
Midwest Parties – Michigan Public Power Agency; Michigan South Central Power Agency; City of Wyandotte, Michigan; City of Hamilton, Ohio; and East Kentucky Power Cooperative
Midwest SATCs – American Transmission Company LLC, GridAmerica LLC,

International Transmission Company and Michigan Electric Transmission Company, LLC

Midwest TDUs – Great Lakes Utilities, Indiana Municipal Power Agency, Lincoln Electric System, Madison Gas and Electric Company, Midwest Municipal Transmission Group, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, Upper Peninsula Transmission Dependent Utilities and Wisconsin Public Power, Inc.

Minnesota Department of Commerce

Montana-Dakota – Montana-Dakota Utilities Company

OMS – Organization of MISO States

Otter Tail – Otter Tail Power Company

PSEG – PSEG Energy Resources & Trade LLC

Reliant – Reliant Energy, Inc.

Steel Producers – Steel Dynamics – Bar Products Division and Nucor Steel

WEPCO – Wisconsin Electric Power Company

WPPI – Wisconsin Public Power, Inc.

WPS Resources – Wisconsin Public Service Corporation, Upper Peninsula Power Company, WPS Power Development, Inc. and WPS Energy Services, Inc.

WUMS Load-Serving Entities – Wisconsin Electric Power Company, Edison Sault Electric Company, Wisconsin Public Service Corporation, Upper Peninsula Power Company, Wisconsin Power and Light Company, Madison Gas and Electric Company and Wisconsin Public Power, Inc.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc., Docket No. ER04-691-003

Public Utilities With Grandfathered Agreements in the Midwest ISO Region Docket No. EL04-104-003

(Issued November 8, 2004)

Joseph T. KELLIHER, Commissioner *dissenting in part*:

I would have granted rehearing on the issue of whether the must offer requirement should be removed from the Midwest Independent Transmission System Operator, Inc.'s tariff in the absence of any compensation in the form of capacity payments for the reasons explained in my dissent in the August 6, 2004 order.[1]

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Joseph T. Kelliher

[1] *Midwest Independent Transmission System Operator, Inc*., 108 FERC ¶ 61,163 at 62,015 (2004).