108 FERC ¶ 61,163
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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| Midwest Independent Transmission System Operator, Inc. | Docket No. ER04-691-000 |
| Public Utilities With Grandfathered Agreements In the Midwest ISO Region | Docket No. EL04-104-000 |

# ORDER CONDITIONALLY ACCEPTING TARIFF SHEETS TO START ENERGY MARKETS AND ESTABLISHING SETTLEMENT JUDGE PROCEDURES

(Issued August 6, 2004)

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FEDERAL ENERGY REGULATORY COMMISSION

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

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ORDER CONDITIONALLY ACCEPTING TARIFF SHEETS
TO START ENERGY MARKETS AND ESTABLISHING
SETTLEMENT JUDGE PROCEDURES

(Issued August 6, 2004)

1. On March 31, 2004, the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) filed a proposed Open Access Transmission and Energy Markets Tariff (TEMT) pursuant to section 205 of the Federal Power Act (FPA).[1] The proposed TEMT contains the terms and conditions necessary to implement a market-based congestion management program and energy spot markets, including a Day-Ahead Energy Market and a Real-Time Energy Market (collectively, Energy Markets), locational marginal pricing (LMP) and a market for Financial Transmission Rights (FTRs). In an order issued May 26, 2004, the Commission set the market implementation date at March 1, 2005.[2]

2. The Energy Markets incorporate the major features used successfully in the three eastern ISOs – PJM Interconnection, L.L.C. (PJM), New York Independent System Operator, Inc. (NYISO) and ISO New England (ISO-NE) – including centralized security-constrained economic dispatch, LMP and market mitigation based on conduct and impact thresholds. We are confident that these features will be successful as applied

[1] 16 U.S.C. § 824d (2000).

[2] *See* Midwest Independent Transmission System Operator, Inc., 107 FERC ¶ 61,191 at P 3, 94 (2004) (Procedural Order).

to the Midwest ISO. This order also reflects collaboration between the Midwest ISO, the Organization of MISO States (OMS) and stakeholders on many issues, in particular in the development of FTR allocations, marginal loss mechanisms and the resource adequacy proposal. Accordingly, we expect that this broad-based, high level of support for major features of the Energy Markets and congestion management system will ensure rapid and successful implementation.

3. Today we will accept and suspend certain tariff sheets of the proposed TEMT and permit them to become effective March 1, 2005, subject to conditions and further orders on grandfathered agreements and Schedules 16 and 17. We also accept certain tariff sheets to be effective on the date of this order, subject to conditions and further order on grandfathered agreements. In order to address the Midwest ISO's unique features, such as the fact that this ISO 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, we will order the Midwest ISO to implement additional safeguards and confidence-building protections at startup and for a transition period. We will also require the Midwest ISO (and its market monitor) to make other compliance filings as ordered below. 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.

# I. Background

4. In an order dated 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,[3] and thus granted the Midwest ISO RTO status.[4] 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. Additionally, the

[3] 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).

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

Commission found that the Midwest ISO's market monitoring program generally satisfied the requirements of Order No. 2000, but required the Midwest ISO to file certain additional information for Commission review.

5. As directed in the December 20 RTO Order, the Midwest ISO filed a proposed Market Monitoring Plan and Retention Agreement. Upon the Commission's acceptance of the documents, they were incorporated into the Midwest ISO's open access transmission tariff (OATT) as Attachments S and S-1, respectively.[5] In a separate order, the Commission accepted, subject to modifications, the Midwest ISO's Market Mitigation Measures as Attachment S-2 to the Midwest ISO OATT.[6] The Midwest ISO submitted proposed revisions to the Market Mitigation Measures, and a technical conference was held; however, as discussed below, the Commission dismissed the requests for rehearing addressing the technical conference, and the compliance filing that it had ordered in the March 13 Order, to better enable the Midwest ISO to prepare the instant filing.[7]

6. 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 (FTR Rules); and (3) market settlement rules. The Commission approved the general direction of the Midwest ISO's energy markets

[5] *See* Midwest Independent Transmission System Operator, Inc., 99 FERC ¶ 61,237 (2002); Midwest Independent Transmission System Operator, Inc., 101 FERC ¶ 61,228 (2002).

[6] *See* Midwest Independent Transmission System Operator, Inc., 102 FERC ¶ 61,280 (2003) (March 13 Order).

[7] Midwest Independent Transmission System Operator, Inc., 105 FERC ¶ 61,147 (2003) (Market Rules Rehearing Order) (dismissing requests for rehearing of March 13 Order, on Market Mitigation Measures); Midwest Independent Transmission System Operator, Inc., 105 FERC ¶ 61,146 (2003) (Market Rules Compliance Order) (dismissing as moot a filing made to comply with the March 13 Order).

[8] *See* Doying testimony at 4.

proposals, reserving judgment on some issues and providing guidance on others.[9] The Commission affirmed many of its conclusions on rehearing.[10]

7. On July 25, 2003, the Midwest ISO filed a proposed TEMT pursuant to section 205 of the FPA (July 25 Filing). Like the instant filing, the July 25 Filing included terms and conditions necessary to implement a day-ahead energy market, real-time energy market and FTR market. The July 25 Filing met with numerous protests, many of which alleged that the filing was incomplete and premature. Following a stakeholder vote, the Midwest ISO filed a motion to withdraw the proposed TEMT, 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]

8. The Commission granted the Midwest ISO's motion to withdraw the July 25 Filing.[12] It also provided, on an advisory basis, guidance on a number of issues raised in the July 25 Filing. Contemporaneously, through the Market Rules Rehearing Order and the Market Rules Compliance Order, the Commission dismissed a compliance filing and outstanding rehearing requests relating to the Midwest ISO's proposed Market Mitigation Measures. The Commission stated in all three orders 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 mitigation measures.

9. The Midwest ISO filed a revised version of the TEMT on March 31, 2004. Its revised filing raised 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

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[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).

[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 Order), *reh'g dismissed*, 105 FERC ¶ 61,272 (2003).

testimony of two witnesses, that it would be unable to operate its energy markets without integrating about 300 pre-OATT grandfathered agreements (GFAs) that are currently effective in the Midwest ISO region. It argues that allowing holders of GFAs scheduling rights similar to their current practice would require a physical reservation, or "carve out," of transmission capacity in the Day-Ahead Market and until the scheduling deadline prior to real-time dispatch. The Midwest ISO 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."[13]

10. The Procedural Order gave an initial response to the threshold GFA issue. The Commission identified specific needs 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,[14] of the GFAs. The Commission ordered GFA parties to file interpretations of their contracts in Stage 1 of the investigation, and established trial-type hearing proceedings – Stage 2 of the investigation – to elicit the GFA information from those parties who were not able to agree in Stage 1. The Commission also offered GFA holders an opportunity to settle their GFAs by voluntarily accepting the GFA treatment that the Midwest ISO proposed in the TEMT. As described above, the Commission also revised the timeline for implementing the proposed TEMT.

11. Stage 2 of the Commission's investigation of the GFAs concludes today with the administrative law judges' presentation of the results of the hearing they held to elicit GFA information that was outstanding after Stage 1. As outlined in the Procedural Order, the Commission will now begin to consider all the evidence developed in Stages 1 and 2 of the section 206 investigation to decide how GFAs should be treated in the Midwest ISO's Energy Markets.[15] Accordingly, this order will not address GFAs other than to acknowledge certain issues that can only be decided in conjunction with the outcome of the GFA investigation. The Commission will make every effort to expedite its upcoming order on GFA issues, keeping in mind the revised timeline for market startup, so that all Midwest ISO market participants may begin their FTR nominations on October 1, 2004.

[13] Transmittal Letter at 9. *See also* Hogan testimony at 6-7, 14-15.

[14] 16 U.S.C. § 824e (2000).

[15] Procedural Order at P 78.

## II. Open Access Transmission and Energy Markets Tariff

12. The Midwest ISO proposes to implement real-time energy imbalance services and a market-based congestion management system through the introduction of a centralized platform for the dispatch of generation resources throughout the Midwest ISO region. It plans to implement a Day-Ahead Energy Market and a Real-Time Energy Market, with LMP, and allocate or auction FTRs to allow market participants to hedge against the costs of congestion in the Day-Ahead Market.

13. The Midwest ISO states that its stakeholders have been involved in the development of all details of the proposed Energy Markets.[16] The Midwest ISO states that the first efforts to define the requirements for energy markets began in November 2000.[17] It adds that stakeholders have had numerous opportunities for input at committee meetings, working groups, task force meetings and special technical conferences.[18]

14. Module A of the TEMT contains a list of defined terms and their meanings, together with common tariff provisions relating to, *inter alia*: the initial allocation of, and reservation priority for, transmission capacity; ancillary services; the open-access same-time information system (OASIS); reciprocity; liability and indemnification; creditworthiness; and dispute resolution.[19]

15. Module B includes all provisions related to point-to-point transmission service and network service, as well as provisions that will govern the applicability of those services.

16. Module C includes the tariff provisions relating to the formation of the Day-Ahead Energy Market, the Real-Time Energy Market and the FTR markets. It delineates the general responsibilities and requirements of entities with a relationship to the markets,

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[16] *See* Doying testimony at 3.

[17] *See* Doying testimony at 4.

[18] *See* Exhibit RD-1.

[19] In the Procedural Order the Commission rejected a portion of the dispute resolution proposal – the Expedited Dispute Resolution (EDR) procedures for disputes regarding GFAs – and established the section 206 investigation in its place. Procedural Order at P 50, 100.

such as the Midwest ISO,[20] market participants and control area operators. Further, Module C lays out the structure and operating procedures for each proposed market.

17. Module D, which was not included in the July 25 Filing, addresses the Independent Market Monitor (IMM) and its responsibilities for market monitoring and market mitigation. The Midwest ISO states that it has revised the proposed market monitoring provisions that the Commission previously accepted[21] to include new provisions related to access to confidential information and revisions to defined terms. The Midwest ISO adds that it has further modified its market monitoring provisions to incorporate the guidance the Commission gave it in the TEMT Order. Specifically, the Midwest ISO says, the revisions to Module D: (1) provide additional detail regarding the definition and analysis of Narrow Constrained Areas and Broad Constrained Areas; (2) clarify how Reference Levels will be established for non-price offer parameters; (3) spell out how default offer mitigation measures may be applied to uneconomic production and certain forms of physical withholding; and (4) exempt generating units from physical withholding in the Day-Ahead Market or the RAC process, if they have no resource adequacy obligation.

18. Module E, which the Midwest ISO is also filing for the first time, contains tariff provisions delineating interim resource adequacy requirements. Module E describes responsibilities for compliance with existing state and reliability resource organization requirements. It also includes tariff provisions to govern designation of network resources and a network resource must-offer requirement. The Midwest ISO states that Module E relies on existing standards and programs. It believes that the proposals will potentially result in some changes to reporting requirements, but no changes with respect to resource adequacy standards. For entities in states with retail choice programs, the Midwest ISO states that Module E may represent change. For example, the Midwest ISO states that Module E will require load-serving market participants to identify the resources that they will rely upon to meet resource adequacy standards, and that it may be unclear in Ohio, Michigan and Illinois which entity has that obligation today.

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[20] The draft 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.

[21] *See* March 13 Order.

19. In addition to its five modules, the proposed TEMT includes various schedules and attachments – some revised from the OATT, and some new – to implement the tariff provisions.

## III. Notice of Filing and Responsive Pleadings

20. Notice of the TEMT filing was published in the *Federal Register*, 69 Fed. Reg. 18,893-94 (2004), with interventions and protests due on or before May 7, 2004. The parties listed in Appendix A filed interventions, protests and comments, as detailed below.[22] Following issuance of the Procedural Order, which was published in Federal Register, 69 Fed. Reg. 32,101 (2004), numerous parties filed interventions in Docket No. EL04-104-000. These motions were ruled upon by the administrative law judges that presided over Stage 2 of the Commission's investigation in that docket.

21. The Midwest ISO TOs request that the Commission reject the March 31 TEMT filing and establish settlement judge procedures without prejudice to the Midwest ISO refiling after the settlement judge process. They argue that the Midwest ISO failed to obtain the support of a large portion of its stakeholders for many aspects of its proposal and, furthermore, that the Midwest ISO made changes in the tariff that did not go through the stakeholder process.

22. Specifically, the Midwest ISO TOs contend that the Midwest ISO failed to vet the TEMT through the Advisory Committee process, including voting.[23] The Midwest ISO TOs argue that other RTOs usually do not file such important matters without first attempting to resolve differences through a member committee process.[24] They add that

[22] Acronyms and short forms used for party names throughout the order can also be found in Appendix A.

[23] *See* Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., Section VI(A)(1), FERC Electric Tariff, First Revised Rate Schedule No. 1, First Revised Sheet No. 44 (Transmission Owner Agreement). *See also* Midwest Independent Transmission System Operator, Inc., 84 FERC ¶ 61,231 at 62,149 (1998) (describing the Advisory Committee's function).

[24] *See* Midwest ISO TOs at 6 (citing New England Power Pool, 100 FERC ¶ 61,287 (2002); PJM Interconnection, L.L.C., 106 FERC ¶ 61,049 (2004)) .

when dealing with controversial issues in the past, the Commission has accorded weight to proposals that received substantial support at the applicable members committee.[25]

23. The Midwest ISO TOs claim that by not bringing the TEMT up for a vote at the Advisory Committee, the Midwest ISO violated its own procedures as well as Commission policy allowing formal means of advising an independent board. They state that when the Midwest ISO was formed, it was intended that the Advisory Committee vote on significant matters in order to provide the Board with guidance on whether or not the Midwest ISO staff recommendations should be accepted. The Midwest ISO TOs further argue that the Transmission Owner Agreement provides for majority and minority reports to be submitted to the Board for its consideration.[26] This policy, they say, was included so that the Midwest ISO would bring its major policy matters and regulatory filings to the Advisory Committee so that the Board can consider all views before it takes action.

24. Next, the Midwest ISO TOs argue that contrary to certain assertions made in the transmittal letter accompanying the TEMT, the Midwest ISO TOs did in fact provide the Midwest ISO comments regarding their concerns surrounding functional separation of responsibilities and associated cost allocation and indemnification issues.

# IV. Discussion

## *A. Procedural Matters*

25. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2003), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

26. We will deny the Midwest ISO TOs' motion to reject the proposed TEMT. An examination of the stakeholder process involves three main questions: (1) whether there was an effective and inclusive stakeholder process; (2) whether the appropriate issues were raised within the process; and (3) whether consensus was reached on the issues raised.

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[25] *See* Midwest ISO TOs at 6-7 (citing New England Power Pool, 105 FERC ¶ 61,300 at P 23 (2003).

[26] *See* Midwest ISO TOs at 8 (citing Midwest ISO Transmission Owner Agreement, FERC Electric Tariff, First Revised Rate Schedule No. 1, at Section VI(A)(1) (Transmission Owner Agreement)).

27. First, the Midwest ISO has utilized a structured, comprehensive and inclusive stakeholder process to discuss large parts of the TEMT. The Midwest ISO TOs admit that "[t]he Midwest ISO instituted a substantial process, including numerous meetings, conference calls, and the collection of written comments regarding drafts of its Markets Tariff."[27] Additionally, the OMS "acknowledges and appreciates the amount of consultation and discussion that has occurred between [the Midwest ISO] and its stakeholders to develop the revised TEMT filing."[28]

28. As the Midwest ISO indicates, the stakeholder process did not begin after the withdrawal of the July 25 Filing, but has been ongoing since November 2000.[29] The TEMT represents direction provided by stakeholders involved in that process as well as directions from the Commission and Midwest ISO staff's own independent assessment.[30] According to the Midwest ISO, this stakeholder process involved 25 significant issue areas that were addressed in nearly 100 key stakeholder discussions and meetings.[31]

29. The Transmission Owner Agreement states that the Advisory Committee shall be a forum for its members to be apprised of Midwest ISO's activities and to provide information and advice to the Board on policy matters of concern to the Advisory Committee, or its constituent stakeholder groups, but that neither the Advisory Committee nor any of its constituent groups shall exercise control over the Board or the Midwest ISO.[32]

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[27] Midwest ISO TOs at 6.

[28] OMS at 5. *See also* Reliant at 3 (stating that the Midwest ISO "and its stakeholders have worked hard and the resulting product addresses much of the criticism leveled against the withdrawn tariff.").

[29] *See* Doying testimony at 4.

[30] *See* Doying testimony at 4.

[31] *Id.* at Exhibit RD-1. We are mindful of the resources needed for stakeholder processes from not only the Midwest ISO, but also from all of its stakeholder groups, and we are aware that resources may sometimes be at the expense of other development areas.

[32] *See* Midwest Transmission Owner Agreement, Section VI (A)(1). *See also* Midwest Independent Transmission System Operator, Inc., 84 FERC ¶ 61,231 at 62,149 (1998) (describing Advisory Committee's function).

30. Second, by and large, many issues were vetted through the stakeholder process. Although the decision to file the TEMT was not voted on at the Advisory Committee, the Midwest ISO has consulted with the stakeholders on the key issues of that filing. The Midwest ISO TOs admit that the Midwest ISO instituted a "substantial process" to develop its filing.[33] We agree. And while the Midwest ISO TOs note that the Midwest ISO may have filed some tariff provisions that were not fully vetted through the stakeholder process, they allude to the fact that this could have been a result of timing rather than any circumvention of the process. Although we are concerned that certain issues in the TEMT may have been changed from the last draft circulated we find that this appears to be a timing issue. There is evidence that the vast majority of all issues were vetted through the stakeholder process.[34] We find that, consistent with the Transmission Owner Agreement, stakeholders were provided with ample opportunity to comment on the issues raised in the proposed TEMT prior to Midwest ISO filing the TEMT with the Commission. We find no evidence that Midwest ISO violated any procedures in filing the TEMT with the Commission. There are no requirements in the existing tariff or the Transmission Owner Agreement that Midwest ISO bring items to a vote in the Advisory Committee prior to filing with the Commission. Furthermore, the Transmission Owner Agreement specifically states that the Advisory Committee may provide information and advice but may not exercise control over the Midwest ISO.

31. The third question, regarding the issue of consensus, is more complex. Many critical issues surrounding the successful operation of energy markets do not lend themselves to easy resolution or to achieving unanimity or even consensus, given the diverse interests of the various stakeholders. The Commission recognizes this, as does the Midwest ISO.[35] Moreover, while the Commission gives serious consideration to

[33] Midwest ISO TOs at 6.

[34] *See, e.g.*, McNamara testimony at 52, 54-57; Volpe testimony at 15-19; Doying testimony at Exhibit RD-1. *See also* OMS at 6 ("[The Midwest ISO's] continued effort to take a cooperative approach regarding the development, implementation and fine-tuning of the terms contained in the TEMT encourages the members of the OMS.").

[35] *See* Gribik testimony at 20 (discussing the stakeholder process on FTR allocations: "The extensive stakeholder discussions have revealed that while some compromise has been possible, it is unlikely that unanimity or a preponderant consensus will be reached on all issues."). *See also* Doying testimony at 10, 14 (identifying GFAs and FTR allocations as particularly contentious issues). The Midwest ISO acknowledges that the TEMT filing includes some proposals that were vetted through the stakeholder process but did not receive affirmative stakeholder votes for inclusion in the proposal. It

(continued)

results reached under the stakeholder process, the issue before us is whether the proposal is just and reasonable or has been shown to be unjust and unreasonable, not whether all (or even most) of the market participants agree.[36]

32. While we encourage and hope for stakeholder consensus on many of the issues surrounding the TEMT, we agree with the Midwest ISO that this is simply not possible given the divergent views of the stakeholders – especially given that the stakeholder processes employed to date have not achieved consensus. Therefore, we believe that establishing a settlement judge process, as the Midwest ISO TOs advocate, will do little to narrow pending issues and will only delay the Energy Markets.

### *B. Readiness and Market Startup Safeguards*

33. All parties engaged in the implementation of the Midwest ISO Day 2 market recognize the scope and challenges of the enterprise. Both the Midwest ISO and the Commission 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. The proposed TEMT and associated testimony by the Midwest ISO witnesses set forth a number of transitional measures in the TEMT market design (particularly in FTR allocation safeguards for base-load resources), as well as readiness metrics not filed with the TEMT, that are designed to provide confidence in Midwest ISO operations.

34. Numerous intervenors have requested further measures to provide both transitional and permanent safeguards of various kinds. As detailed in this section, we will require the Midwest ISO to create, file and operate under a set of transitional and permanent safeguards, as an addition to its TEMT proposal. The safeguards should provide additional confidence in the reliable implementation and initial functioning of the Day 2 market and provide some additional limits on exposure to the Midwest ISO Energy Markets prices and transmission usage charges during the first months and years of the markets' operation. In subsequent sections of this order, we will also require the Midwest ISO to make certain modifications to the filed tariff sheets that provide other protections.

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states that in the absence of feasible alternative proposals from stakeholders, it included these proposals in the TEMT. *See* Transmittal Letter at 5.

[36] *See, e.g.,* New England Power Pool, 107 FERC ¶ 61,183 at P 39 (2004) (acknowledging, but rejecting stakeholder compromise regarding cost allocation methodology).

35. The transitional market safeguards are intended to achieve two primary goals: (1) to give the Midwest ISO sufficient experience with its market and system operations to allow it to detect and correct initial problems; and (2) to afford market participants experience with the market prior to increased exposure to price uncertainties due to, for example, marginal congestion and loss charges. The period each transitional market safeguard covers is based on achieving these goals.

36. The six safeguards introduced in this section are ordered roughly according to the period of time that they will be in place. First, we address measures that will take place largely prior to the start of the Day 2 market: additional Commission oversight and reporting requirements regarding the achievement of reliability and readiness metrics that the Midwest ISO and market stakeholders have set forth for current and Day 2 operations, taking into account the recommendations of the U.S.-Canada Power System Outage Task Force and the audits conducted by the North American Electric Reliability Council (NERC).

37. We then turn to two measures that will be in place during the first few months of operations. The first of these is a "cutover" plan to support full operational reversion to reliable system operations and transmission scheduling in the event of a major Midwest ISO system failure. The second is a temporary cap on supply offers into the Midwest ISO energy markets to limit the price impacts of any early problems with market operations.

38. Next, we establish two measures that will be in place for a 5-year transition period. The first of these measures requires the Midwest ISO to calculate marginal loss charges, but allows market participants to pay their current loss charge or a Midwest ISO-calculated average loss charge. New transmission customers will be required to pay marginal loss charges one year following the start of the market. Following this transition, all market participants will be assessed marginal loss charges. The second measure provides market participants in load pockets defined as such at the start of the market with enhanced protection against congestion charges for existing transmission service to network resources or system purchase contracts external to the load pocket, because of these participants' particular vulnerabilities to unhedged congestion charges.

39. Finally, on a permanent basis, but with the expectation that it will prove most useful in the first months of the market, we provide the Midwest ISO with authority to revise LMPs *ex post* in the event of transitory data and software errors, system failures, and other operational problems.

40. In each subsection discussing a safeguard measure, we present and answer the comments and protests of market participants relevant to that measure.

### 1. Reliability, Performance Assessment and Audit

#### a) The Midwest ISO's Proposal and Other Relevant Efforts by the Midwest ISO and Other Entities

41. Following the August 14, 2003 blackout, there have been a number of initiatives relevant to the Midwest ISO's ability to operate reliably the power system in its footprint. Because intervenors raise this issue with respect to Day 2 operations, we list these initiatives and their recommendations here and discuss their results and implications for the Day 2 implementation below.

42. Following the blackout, the U.S.-Canada Power System Outage Task Force (Task Force) produced an interim report in November 2003[37] and a final report in April 2004.[38] Both the Interim and the Final Blackout Reports made numerous recommendations for improvements in reliability that were applicable to any system operator. In response to these recommendations the Commission issued a policy statement on bulk power system reliability to address the need to expeditiously revise NERC's reliability standards in order to make these standards clear and enforceable.[39] The Commission expects public utility compliance with NERC's reliability standards, clarifying that Good Utility Practice includes compliance with these standards.[40] In addition, the policy statement

[37] U.S.-Canada Power System Outage Task Force, Interim Report: Causes of the August 14, 2003 Blackout in the United States and Canada (2003) (Interim Blackout Report).

[38] U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations (2004) (Final Blackout Report).

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

[40] *See id.* at 23.

addresses recovery of prudent power system reliability costs, and the need for communication and cooperation between the Commission and the states, as well as with Canada and Mexico regarding reliability issues.[41]

43. On January 26, 2004, NERC recommended a list of corrective actions for the Midwest ISO to be completed no later than June 30, 2004.[42] These actions were in five areas: (1) reliability tools; (2) visualization tools; (3) training; (4) communications; and (5) operating agreements. A NERC audit conducted in February 2004 found that the Midwest ISO had completed the requirements in each area except for operating agreements.[43] The audit team found that Midwest ISO meets its responsibility as the Reliability Coordinator for the safe and reliable operation of the transmission system and experiences no other impediments to its ability to implement its RTO reliability plan.[44]

44. The Commission has also addressed reliability of Day 2 operations explicitly in the TEMT Order. In that order, the Commission advised the Midwest ISO to examine its proposed changes in functional responsibility for reliability – primarily shifts in responsibility from the existing control area operators to the Midwest ISO – through the NERC Functional Model.[45] We examine compliance with this requirement and relevant

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[41] OMS notes that the Final Blackout Report expressed concern about Reliability Coordinators and control areas and recommends that the Midwest ISO pursue the specific recommendations for strengthening its role as Reliability Coordinator.

[42] *See generally* Final Blackout Report at Appendix D.

[43] NERC, Audit Report for Midwest ISO – Final Report (April 6, 2004) (NERC Final Audit Report), *available at* http://www.nerc.com/~rap/audits.html. In the area of operating agreements, the Audit Team recommended that the Midwest ISO shall review the contract between MAPPCOR and its members to clarify and establish the Midwest ISO authority of the Reliability Coordinator. The Midwest ISO shall notify the NERC Vice President of compliance when this recommendation is implemented.

[44] *See* NERC Final Audit Report at 4. The audit team also made recommendations in the area of best practices for a Reliability Coordinator. The team recommended that the Midwest ISO coordinate with its members to implement control area under-voltage, under-frequency and manual load-shedding programs, improve real-time contingency analysis run time to less than five minutes, perform comprehensive analysis of multiple contingencies, establish a process to track the response of control areas to Reliability Coordinator directives, and formalize training programs.

[45] *See* TEMT Order at P 46.

protests and comments below in section IV (C). Here we note that the TEMT Order advised the Midwest ISO to address analysis of potential adverse impacts, if any, on reliability resulting from the shift in functional responsibilities and new cost obligations, and corrective measures that can be taken that result from changes in control area responsibilities.

45. Finally, another set of intervenors' concerns, with some overlap with Day 2 reliability readiness, is Day 2 market readiness. In its transmittal letter for the proposed TEMT, the Midwest ISO notes that it "has repeatedly committed to its stakeholders that it will not commence the Energy Markets . . . unless it is ready to operate effectively."[46] To that end, the Midwest ISO and its stakeholders have developed over 100 metrics to evaluate progress towards its readiness to implement the Energy Markets. It has also retained an independent readiness advisor (Readiness Advisor) to report to the Midwest ISO's Board of Directors and its Advisory Committee progress towards achieving each metric in the specified timeframes and to evaluate the importance of each metric in the overall market implementation plan. This reporting responsibility will continue until the market starts. The Midwest ISO states that if it "is unable to substantially accomplish these identified metrics, [it] will announce a delay in the commencement of the Energy Markets to ensure a successful start of market operations."[47] Moreover, the Midwest ISO notes its reporting requirement to the Commission to provide reports every 60 days that document progress toward completion of the Energy Markets.[48]

### b) Protests and Comments

46. Many intervenors stress the need to ensure reliability in the transition to the Day 2 market.[49] A number of intervenors state that Midwest ISO must verifiably complete all reliability measures required by NERC and receive any relevant certifications. Several intervenors want the results to be filed, for comment, with the Commission.[50]

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[46] Transmittal Letter at 22.

[47] Transmittal Letter at 23.

[48] Transmittal Letter at 23.

[49] *See* Alliant, ATCLLC, Basin Electric, Cinergy, Consumers Energy, Dairyland, Detroit Edison, Minnkota, NRECA, WEPCO, Wisconsin Commission, WPS Resources, and Xcel.

[50] *See* Alliant; ATCLLC; Cinergy; Consumers Energy; Detroit Edison; WEPCO.

47. The Michigan Commission argues that the Commission should not require the Midwest ISO to comply with performance metrics as a condition for the start of the Day 2 market. The Michigan Commission has confidence that the measures already instituted are fully adequate to support an efficient Day 2 market. It encourages the Midwest ISO to resolve issues on performance metrics through the stakeholder process.

48. OMS "expects that [the Midwest ISO]'s technical readiness performance metrics will be met prior to the Day 2 market start-up."[51] OMS further states that "upon further stakeholder review, [the Midwest ISO] may need to add performance metrics related to [the Midwest ISO]'s commercial operational readiness."[52] Moreover, "performance metrics must include details about [the Midwest ISO]'s testing plan."[53]

49. OMS recommends that the Midwest ISO seek stakeholder input into the Readiness Advisor's Verification Plan. Moreover, it recommends that this plan should be finalized well before Day 2 start-up to allow the Readiness Advisor to provide the Commission and stakeholders "with thorough and accurate measures" of the Midwest ISO's readiness to operate the Day 2 markets.[54] The Wisconsin Commission makes similar requests.[55]

50. Consumers states that further training is needed to ensure the Midwest ISO's readiness for Day 2 operations.

51. In its Answer, the Midwest ISO acknowledges that development and refinement of the models that underlie the operation of the energy and transmission markets require stakeholder support to improve accuracy but also to provide acceptance that the models are appropriate for the tasks. Hence, it "commits to enhancing its model validation process to allow for transparent stakeholder involvement in model review."[56] The Midwest ISO argues that its milestones for readiness "are adequate" but also commits to

[51] OMS at 45.

[52] OMS at 45.

[53] OMS at 46-77.

[54] OMS at 45.

[55] Wisconsin Commission at 26-32.

[56] Midwest ISO Answer at 45.

improving transparency regarding system training, performance and testing activities in the months prior to TEMT implementation. The Midwest ISO will also increase its efforts at training.

### c) Discussion

52. We note three areas of concern about the Midwest ISO's readiness to implement the Day 2 markets reliably and effectively: (1) generic reliability issues, especially those identified by the Task Force and subsequent NERC audit; (2) reliability issues that could emerge as a result of the implementation of the Day 2 market – for example, as control area operators change functional responsibilities; and (3) readiness to operate the market such that, assuming that reliability is ensured, market systems and measurements used to develop market prices are sufficiently accurate and dependable.

53. Commission staff participated with NERC in the Midwest ISO Readiness Audit, described above, conducted in February 2004. The audit team reviewed the Midwest ISO operation regarding all of the various reliability topics with concentration on management support, Midwest ISO shift staff capability and tools, operation planning, training programs and backup control facilities. Based on the results of the NERC audit, we are encouraged that there have been substantial improvements in the monitoring and operations of the power system. NERC has also recommended additional steps. We encourage the Midwest ISO to comply with all the NERC recommendations and, as described below, will require it to certify that its systems are ready for reliable operations upon the start of the Day 2 market.

54. As we discuss in section IV (C) of this Order, the Midwest ISO and market participants have complied with the guidance the Commission provided in the TEMT Order in developing a set of functional responsibilities appropriate to the reliable operation of the Day 2 market. We are confident that the progress made in defining functional responsibilities, coupled with concurrent measures to improve reliability and readiness, should together be sufficient to maintain reliability. However, we find that the Midwest ISO has not explicitly addressed in the proposed TEMT the matter of ensuring that the transition in functional responsibilities will not adversely affect reliability. We will require the Midwest ISO to file an explanation of this within 60 days of the issuance of this order. Since the Midwest ISO is the entity that must define the changes in functional responsibilities for all control area operators and other entities, we will require it to take stock of readiness and capabilities in these entities prior to the implementation of the Day 2 market.

55. On market readiness, we will require the Midwest ISO to consult with and adopt OMS's recommendations for metrics related to commercial operations readiness and the testing plan. The Midwest ISO must certify to the Commission, 30 days before market startup, the reliability and readiness of its systems. The Commission will not approve the

start of the markets until it receives the certification. We will also require the Midwest ISO's independently evaluated Verification Plan to be filed with the Commission, on an informational basis, at least three months prior to the market start. We also request that OMS make an informational filing to advise the Commission of OMS's views on market readiness.

### 2. Temporary Cutover to Alternative, Reliable System Operations and Market Settlement in the Event of Severe Market Operations Failure

56. Cinergy notes that in the transition to Day 1 operations, the Midwest ISO had "safety net" redundancies that allowed control areas to take over certain functions if Midwest ISO could not. Cinergy observes that the Day 2 market plan does not have such a plan.[57] Cinergy's comments are made in support of a request for thorough testing of the planned Day 2 system and market operations. We support thorough testing, but we will also require appropriate functional redundancies to provide such a safety net for a temporary period.

57. The Midwest ISO has not proposed a plan to address system operations in the event of a severe operations failure. We have elsewhere supported such plans. For example, in 1999, the Commission approved a NYISO plan to cut over to New York Power Pool operations as they were prior to NYISO operations (with some appropriate changes) in the event of a serious market operational problem that occurred during the first two weeks of NYISO operations.[58] The problem would have to have been severe enough that it could not be handled through recourse to existing provisions in the market rules or operating manuals. Subsequent to the problem being identified and corrected, the plan called for the next two-week period to begin with the same cutover provisions in place until the ISO could operate problem-free for two weeks, at which time the cutover plan would expire.

58. There is no legacy of centralized power pool dispatch in the Midwest ISO footprint that allows for a cutover similar to the NYISO plan, but all the existing control areas will be in place, as will the Midwest ISO's current transmission scheduling capabilities. Hence, we will require that no later than three months prior to the start of the Day 2 market, the Midwest ISO file with the Commission a detailed plan, including demonstration of successful testing of the plan, for cutover to decentralized power system operations in the event of a serious failure of Day 2 operations. Control area operators

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[57] Cinergy at 60.

[58] New York Independent System Operator, Inc., 88 FERC ¶ 61,228 (1999).

will need sufficient capabilities through this period to reliably operate their systems and obtain interchange schedules through the Midwest ISO OASIS site. Given the scope of the Energy Markets, we will require a four-week window of Day 2 market operations to be completed without the need for a cutover before the cutover plan expires. We will also require that if the cutover plan is activated, the window will start again upon the restart of the Midwest ISO Day 2 operations.

### 3. Transitional Limits on Supply Offers in the Energy Markets

#### a) The Midwest ISO's Proposal

59. Under the proposed TEMT, the Midwest ISO will operate three markets for generation services: (1) a Day-Ahead Energy Market; (2) a Reliability Assessment Commitment (RAC); and (3) a Real-Time Energy Market. In the Energy Markets, the Midwest ISO will calculate LMPs for settlement of spot sales and purchases of energy and for calculation of transmission usage charges. Offers by Generation Resources can include start-up costs, minimum load costs and energy. Elsewhere in this order, we discuss the merits of the proposed TEMT rules in this regard, including limits on Generation Offers for purposes of market power mitigation. In this section, we discuss transitional safeguards on Generation Offers that will supersede the TEMT, as modified, for a period of two months following the start of the Day 2 market.

#### b) Protests and Comments

60. Several intervenors urge that the LMP markets be phased in, beginning with congestion management based on central dispatch but not using LMP. For example, NRECA proposes that the Commission require Midwest ISO to implement first a "shadow price" scheme to show indicative LMPs. NRECA claims that this will provide appropriate economic signals for investment in transmission prior to actual LMPs. NRECA urges such a phased approach in Midwest ISO load pockets.[59] WPS Resources proposes that the Midwest ISO market start with a centralized dispatch, but without LMP.

61. Midwest TDUs request that the Day 2 market should start with cost-based bidding, for a period at least covering the first summer of market operations.[60] Midwest TDUs state that such a rule would be consistent with PJM's implementation of cost-based bidding in its LMP market for the first two years of operations. They further argue that

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[59] *See* NRECA at 25.

[60] *See* Midwest TDUs at 28.

while restrictive, such a provision could be based on the same production cost data being gathered or estimated by the Midwest ISO IMM for reference prices for the first 60 days of market operations under the proposed TEMT.[61]

### c) Discussion

62. We do not support postponing the implementation of LMP in the Midwest ISO Day 2 market for purposes of learning about which transmission constraints are likely to bind or gaining experience with other types of centralized dispatch. First, market participants in the Midwest ISO footprint are well aware of the major constrained flowgates in the region, due to the frequency with which Transmission Loading Relief (TLR) procedures are used. While this congestion pattern will change under LMP, it is likely that currently persistent constraints will continue to bind. Moreover, FTRs are a mechanism for hedging transactions between known points of receipt and delivery that is independent of particular constraints that bind between the points. As discussed above, the approach that we will take in this order is to ensure that sufficient FTRs are available under the LMP system or that some other congestion hedge backstop can be elected. Second, any alternative to LMP will also have an impact on market participants and thus necessitate continuation of the stakeholder process to determine how congestion costs are shared. While the WPS Resources proposal to begin a centralized dispatch without LMP is a recommendation that has some merit, it would require that the costs of market redispatch in such a large region be assigned on some zonal average basis to minimize cross-subsidies. We will not begin down this path now, as it would require delaying the market while stakeholders discuss the appropriate allocation of redispatch costs.

63. However, we will establish some transitional mechanisms for managing exposure to LMPs and transmission usage charges. We will require market participants to submit cost-based bids for Generation Resources to the Day-Ahead Market, RAC and Real-Time Market for two months following the start of the Day 2 market. Our purpose here is not to manage potential market power, but rather to afford the Midwest ISO and market participants experience with the energy markets and congestion pricing under LMP prior to allowing for the less restrictive energy bidding under the proposed TEMT. We accordingly direct the Midwest ISO to file, within 60 days of the date of this order, tariff sheets implementing this temporary transition LMP pricing plan. The tariff sheets should describe the pricing mechanism and designate a sunset date upon which they will expire and the longer-term LMP pricing tariff sheets will become effective.

[61] *See* Patton testimony at 31.

64. As the Midwest TDUs note, under the proposed TEMT, the IMM will conduct surveys and estimate production costs as a basis for establishing reference levels at the start of the market from which to measure conduct and impact tests for market power mitigation.[62] We will require the IMM to simultaneously provide oversight for this transition mechanism, which will run concurrently.

65. We further note that the two months in question are, under the current schedule for implementation of Day 2 operations, prior to the summer months and under conditions of surplus capacity in most of the Midwest ISO footprint. Hence, these offer requirements are likely to reflect competitive market conditions and thus not interfere much with the expected energy offers of competitive suppliers.

### 4. Transitional Safeguards for Exposure to Marginal Loss Charges

#### a) The Midwest ISO's Proposal

66. In the Declaratory Order, the Commission affirmed that the Midwest ISO should implement marginal loss pricing as a means to achieve a least-cost dispatch.[63] We noted that in a large region with remote generation resources that would seek to participate in the spot energy markets, it is particularly important to account for marginal losses.[64] Furthermore, we required the Midwest ISO to develop a mechanism to return the resulting surplus revenues to its customers in a way that is equitable and that does not distort the marginal price signal. As described in more detail in section IV (E), in the proposed TEMT, Midwest ISO has again proposed LMP with a marginal loss component and a method of allocating marginal loss surplus that basically achieves our objective. The surplus will be refunded on the basis of loss pools composed of individual control areas or aggregations of control areas, and allows for loss pools that have higher losses to receive more of the surplus. As described in section IV (E), we will accept the implementation of marginal losses. However, many market participants are concerned that, even with the refund, they will be exposed to marginal loss charges well above the loss charge that they currently pay under existing OATT transmission service. Hence, here we consider a transitional safeguard allowing marginal loss calculation but suspending marginal loss charges above average or historical loss charges for a period of five years.

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[62] *See infra* Section IV (E).

[63] *See* Declaratory Order at P 53.

[64] *See id*.

### b) Protests and Comments

67. Midwest TDUs urge that the Commission direct the Midwest ISO to develop a transition mechanism to prevent or mitigate cost shifts due to marginal loss pricing. They state that the simplest such mechanism would be to exempt existing agreements from marginal loss pricing or to apply the proposed refund of marginal losses charges back to average loss charges as in the proposed GFA Option B.[65]

68. WUMS Load-Serving Entities request an exemption from marginal loss charges for all WUMS parties' network resources, which would instead pay average losses.[66] The proposed mechanism is that "any loss overcollection relative to losses for existing service shall be returned to the [load-serving entity] in proportion to its loss payment" or the development and implementation of a "fully effective hedge for such loss payments" by the Midwest ISO.[67] WUMS Load-Serving Entities base this request on the 15-20 percent of WUMS annual energy requirements that is imported, the large proportion of joint ownership of baseload units that fall outside the control areas where load is located, and the heavy loading on transmission lines into and within WUMS.

69. Wisconsin Commission notes that Wisconsin utilities invested in their generation resources on the basis of expected costs of transmission, and that given their expected higher-than-average exposure to line losses, new marginal loss charges would be detrimental to the value of existing resources and could delay investment in new ones.

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[65] As described in the Procedural Order, under Option B:

> [T]he Midwest ISO would charge the GFA Responsible Entity the cost of congestion for all transactions pursuant to the GFA, but – if the GFA Scheduling Entity submits the bilateral transaction schedule a day ahead, in keeping with section 39.1.4 – the Midwest ISO will credit back to the GFA Responsible Entity the costs of congestion resulting from day-ahead schedules that the GFA Responsible Entity clears in the Day-Ahead Market. The Midwest ISO will also charge the GFA Responsible Entity the cost of losses for all transactions under the GFA, then – as before, if the GFA Scheduling Entity has timely submitted a conforming schedule for the GFA – credit back to the GFA Responsible Entity the difference between marginal losses and system losses at the GFA source and sink points.

Procedural Order at P 21 (internal citations omitted).

[66] WUMS Load-Serving Entities at 41-42.

[67] WUMS Load-Serving Entities at 41.

The Wisconsin Commission is "hopeful that [the Midwest ISO] and its stakeholders can find an equitable solution to this problem," but if not, it will support efforts by Wisconsin load-serving entities to "improve this aspect of the TEMT."[68]

70. Other parties commenting on or protesting aspects of marginal loss pricing relevant to our decision here but not explicitly requesting exemption from marginal loss charges include Crescent Moon, Great Lakes, Midwest ISO TOs, Otter Tail, and Southwestern. Their comments and protests are reviewed and responded to in section IV (E).

### c) Discussion

71. We have supported the use of marginal losses in LMP in prior Midwest ISO orders because it leads to a least-cost dispatch that reflects the true costs of transmission.[69] Knowing the loss component of the locational price allows the dispatcher to serve load at a particular location with less expensive generation than if losses were not taken into account in the dispatch. The scope of the Midwest ISO market, with significant potential losses if certain generation were dispatched for spot power through the centralized market, makes it more important to ensure that a true least-cost dispatch is attained. Moreover, as we observed in the Declaratory Order, average loss pricing will result in a higher-cost dispatch, entail cross-subsidies and add to uplift charges. However, we did note in the Declaratory Order that we would consider an average loss approach acceptable as a transition mechanism, as we do here for the reasons discussed below.[70]

72. As with other aspects of the Energy Markets, we will take steps here to build experience with LMP while mitigating its impact for a period of time. We note that GFAs use a significant percentage of the transmission system, and that the Midwest ISO has proposed to exempt GFAs from marginal loss charges.[71] Moreover, market participants in at least one region (the WUMS load pocket), are concerned that the proposed allocation of the loss revenue surplus will not be distributed appropriately to keep them whole with respect to the loss charges in their current transmission service.

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[68] Wisconsin Commission at 32.

[69] *See, e.g.,* Declaratory Order at P 31.

[70] *See* Declaratory Order at P 58.

[71] We do not address treatment of marginal losses with respect to GFAs in this order.

The Midwest TDUs are also concerned about the impacts of the transition to marginal loss pricing.

73. The transition to LMPs reflecting marginal losses has been contentious in other ISOs and RTOs with respect to the allocation of the surplus loss revenues, leading to revisions in the allocation methodology once experience is gained. Parties have sought reversion to average loss pricing.[72] In the past, once marginal loss pricing has been established for all market participants, we have declined to revert to average losses.[73] We continue to support the calculation of marginal losses as essential to achieving a least cost dispatch. However, to give market participants more time to adjust to the LMP approach for setting prices and to develop confidence in market processes, we will permit surplus loss revenues to be credited to those participants whose costs from marginal losses exceed the costs that would result from average loss pricing. In other words, marginal losses will be credited back to a historical loss charge or average losses for these participants. This transitional loss refund approach will be 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.

74. To implement this interim measure, we will require the Midwest ISO to implement LMP with marginal losses, but refund the difference between the marginal loss charge and either an average loss or a historical loss charge to all existing transmission customers. Entities will be given this refund based either on historical loss charges associated with existing transmission service, or otherwise on average loss charges calculated by the Midwest ISO.

75. We recognize that average losses can be calculated several different ways. Among these are the "scaled" marginal losses, currently used by the CAISO, and the Midwest ISO's own proposal to calculate an average loss charge based on actual losses for those parties electing GFA Option B.[74] While the Midwest ISO apparently has not defined that average loss calculation yet, it has stated that the average will be determined

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[72] *See* Northeast Utilities Service Company and Select Energy, Inc. v. ISO New England Inc. and New England Power Pool, 105 FERC ¶ 61,122 (2003), *reh'g pending*.

[73] Northeast Utilities Service Company and Select Energy, Inc. v. ISO New England Inc. and New England Power Pool, "Order Denying Complaint," Docket No. EL03-216-000 (Issued October 24, 2003).

[74] *See* Module C, Section 38.8.3.b, Original Sheet Nos. 447-51.

"on an equitable basis."[75] It is appropriate that the Midwest ISO should develop a single methodology for the refund of the difference between marginal and average losses. We will require the Midwest ISO to file tariff sheets implementing the transitional loss calculation measure and refund mechanism within 60 days of the issuance of this order.

76. We further recognize that such a refund measure could dampen the incentive to make efficient purchases in the spot market. Hence, we will require the Midwest ISO to consider additional rules that encourage market participants to make efficient purchases from the spot market during the transition period over which the interim measure applies.

77. This transitional measure has several advantages. It addresses the circumstances of many parties that perceive that they could pay higher rates than they do today under existing contracts, because many load-serving entities in the Midwest ISO footprint serve their load with distant generation that they own or have under long-term contracts. It does not require significant additional preparation by the Midwest ISO to implement, since the Midwest ISO has developed a marginal loss pricing as part of its proposal for market startup and its current loss method is already operational. Moreover, market participants will experience marginal loss pricing for the transition period with fewer concerns about financial exposure.

78. As noted, the marginal loss surplus rebate discussed here will extend to customers requesting new transmission service from the Midwest ISO following the start of the Day 2 market for one year. Following this period, new customers will be charged marginal losses and will also be entitled to receive a portion of the marginal loss revenue surplus according to filed tariff rules.[76]

79. As stated below in section IV (E), we will also require the Midwest ISO and stakeholders to continue discussions about methods for refunding the marginal loss surplus. We will require the Midwest ISO to file a refund method, possibly based on the proposed loss pools approach, no later than 270 days after the start of the Day 2 market.

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[75] *See* Module C, Section 38.8.3.b.iii, Original Sheet No. 451.

[76] Until the termination of this measure for existing transmission customers, the loss surplus will be based solely on loss charges to new transmission customers.

### 5. Transitional Safeguards for FTR Allocation

#### a) The Midwest ISO's Proposal

80. The Midwest ISO proposes to allocate FTRs to provide a hedge against the congestion charge component of LMPs. As section IV (D) describes in more detail, FTRs will be directly allocated annually for a one-year period in a four-tier procedure under which market participants can nominate FTRs between any eligible points of receipt and withdrawal in each tier. That is, market participants can request FTRs in the order of what they perceive to be their expected financial value rather than in order of historical transmission usage. Under the requirement of simultaneous feasibility, this will result in certain nominated FTRs not being awarded (pro-rationed) to some entities due to other entities' flexibility not to nominate FTRs from generation resources that have historically provided "counterflow" that made other transmission service feasible. To mitigate this outcome, the Midwest ISO proposes a transitional safeguard in the FTR allocation methodology: the assignment of counterflow FTRs, designed to allow any entity within the footprint to receive sufficient "restored" FTRs, if needed, to hedge transmission service from baseload generation resources.

#### b) Protests and Comments

81. Many intervenors argue that this transitional restoration of FTRs is not sufficient to hold them harmless against congestion charges associated with generation resources that have historically received firm transmission service.[77] Market participants in significant load pockets in the Day 2 markets (*i.e.*, already identified as NCAs) voice particular concern.[78]

82. A number of intervenors propose additional transitional protection against exposure to congestion charges.[79] WUMS Load-Serving Entities propose an alternative, transitional congestion cost hedging method for use in persistently congested areas, such

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[77] *See* Alliant; American Forest & Paper; Crescent Moon Utilities; Great Lakes; Midwest TDUs; Minnesota Entities; NRECA; PSEG; Southwestern; WPPI; WUMS Load-Serving Entites; Xcel.

[78] *See* WUMS Load-Serving Entities. These prospective Market Participants are located in the WUMS region, the only area that the Midwest ISO IMM identified as a load pocket prior to the start of the Day 2 markets.

[79] *See* Alliant; Midwest TDUs; Southwestern; WEPCO; Wisconsin Commission; WPPI; WPS Resources; Wisconsin Retail Customers Group; Wisconsin Transmission Customer Group; WUMS Load-Serving Entities.

as WUMS, where FTR allocations are subject to potentially substantial pro-rationing and FTR restoration under the TEMT may not be sufficient.[80] With respect to FTRs, WUMS Load-Serving Entities in particular seek additional protection for existing firm transmission service for generation resources located outside the WUMS area (hereinafter, external sources), either within or outside the Midwest ISO footprint (but, in the case of the latter, delivered to the Midwest ISO boundary). WUMS Load-Serving Entities propose that to the extent that nominated FTRs for external sources are pro-rationed following the four tiers of the Midwest ISO allocation process (including the restoration process), then the Midwest ISO should make available to entities with such external sources the option to elect Additional Congestion Pricing Protection (ACPP), which would hold them harmless from congestion charges, subject to certain scheduling and settlement rules.

83. WUMS Load-Serving Entities propose the following rules for parties electing ACPP. First, such parties shall nominate, by the end of Tier 2 of the Midwest ISO allocation process, FTRs for at least 50 percent of the eligible megawatts represented by external sources. WUMS Load-Serving Entities present this "proportionality restriction" as a means by which to mitigate the incentive to focus nominations in the earlier tiers on acquiring internal WUMS FTRs while allowing any consequent pro-rationing in the external FTRs to be covered by ACPP. However, WUMS Load-Serving Entities argue that any further requirement that parties electing ACPP nominate early in the allocation process will undercut their ability to acquire a reasonable quantity of internal WUMS FTRs.

84. Second, a party who elects ACPP will be subject to a type of "use-it-or-lose-it" provision with respect to any surplus FTR revenue associated with external sources. Third, a party that elects ACPP shall be "held harmless for all use of firm transmission service associated with External Sources for which the party sought FTR coverage in the Midwest ISO's FTR allocation process." Moreover, the Midwest ISO will retain, although in the party's name, and administer all of the party's FTRs associated with external sources received through the allocation process.

85. Fourth, FTRs received through the Midwest ISO nomination process shall be defined based upon the existing firm transmission service associated with existing Network Resources. Fifth, for firm transmission service associated with an external source, the party electing ACPP "shall be held harmless from congestion costs incurred

[80] *See* WUMS Load-Serving Entities at 27-41.

for deliveries scheduled in the day-ahead market from the source node of the Network Resource to the sink node of the Network Load."[81]

86. Sixth, administrative costs and uplift associated with providing ACPP shall be charged to Midwest ISO market participants based on Schedule 17 or an equivalent mechanism. Seventh, WUMS Load-Serving Entities propose that the Midwest ISO shall pay all costs and receive all revenues associated with the FTRs that it holds for parties electing ACPP. If at the end of any annual period the FTR revenues in such an account exceeds the administrative costs of providing ACPP, then they can be used to offset any uplift charges associated with provision of ACPP and then any other Schedule 17 charges. Finally, ACPP shall be available until the first annual Midwest ISO FTR allocation process on or after January 1, 2010. Upon expiration of ACPP provisions, the Midwest ISO shall return to each eligible party any FTRs retained by the Midwest ISO in that party's name.

87. WUMS Load-Serving Entities propose that ACPP shall be available to areas that are designated as Narrow Constrained Areas (NCAs) at the start of the Midwest ISO Day 2 market. They suggest that alternatively, the Commission could offer ACPP more generally, in which case eligibility could be a function of: (1) an NCA designation for Network Load; (2) the existence of a generation and/or transmission construction program to eliminate persistent congestion within a reasonable period of time; (3) the ownership of or contract with external sources and demonstration of significant net firm import of energy from such sources; and (4) that the eligible parties agree to abide by the rules set forth above.

88. In its Answer, the Midwest ISO states that the additional congestion hedge in the WUMS proposal would substitute for the restoration step proposed in the Midwest ISO FTR allocation, at least for the subset of entities that qualified for such treatment. It suggests, more generally, that such a substitution could help address the concerns of those market participants who protest the requirements of the restoration step (such as the assignment of counterflow FTRs). To this end, "the Midwest ISO would suggest investigation of other processes (including those that have been used elsewhere to resolve similar stakeholder concerns) that might potentially result in a more coherent and efficient allocation methodology."[82] It cautions that such an investigation and subsequent stakeholder discussion is unlikely to be completed in the time frame envisioned for the FTR allocation.

[81] WUMS Load-Serving Entities at 34-35.

[82] Midwest ISO Answer at 21.

89. In its Answer, Cinergy requests that the Commission reject any special treatment for WUMS Load-Serving Entities. Cinergy notes that many parties in the Midwest ISO footprint have existing firm transmission rights. Cinergy is particularly concerned that WUMS Load-Serving Entities not benefit financially from special treatment at the expense of other parties. Cinergy requests that the Commission focus its efforts on ensuring that the Midwest ISO FTR modeling and allocation process is accurate and fair.

#### c) Discussion

90. We find it appropriate to provide an expanded congestion cost hedge to entities located in an NCA designated as such at the start of the market or within six months of the start of the market. This measure will be allowed for a five-year transition period. 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 the changes in the market design. We find this additional hedge particularly appropriate given that the proposed Midwest ISO FTR allocation provides for flexible FTR nomination, which could result in oversubscription on the most congested lines. The Commission has elsewhere approved transitional measures for load pockets to similar effect. In particular, in New England, the Commission approved a transitional transmission upgrade program whose costs are shared by all parties in the region to increase imports to the load pockets of Boston and Southwestern Connecticut.[83]

91. We will conditionally accept aspects of the WUMS Load-Serving Entities' proposal as the basis for providing an expanded congestion cost hedge. As in this proposal, parties eligible for this coverage will voluntarily elect to receive it; once they do so, they will be subject to the rules that are discussed next.

92. We will require any party electing to receive the expanded congestion cost coverage to abide by the following rules. First, FTRs being nominated should be distinguished between those from network resources "internal" to both the control area and the state where the nominating entity is located and those from network resources that are "external" to both the control area and the state. Only FTRs from external sources are eligible for expanded congestion cost coverage. Second, an entity electing

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[83] *See* New England Power Pool and ISO New England Inc., 101 FERC ¶ 61,344 (2002) (requiring socialization of transmission upgrades into Southwest Connecticut to the ISO-NE footprint on the basis that it would moderate the impact of a potential increase in LMPs within that area).

this coverage must nominate the total FTRs associated with its forecast peak load and do so through the Midwest ISO allocation process in order of resource capacity factors; that is, baseload resources first followed by intermediate and peaking resources. The resulting FTR allocation will be held by the nominating party, but the Midwest ISO will divide the allocation into two accounts, the internal FTRs and the external FTRs, and treat the external FTRs differently for settlement purposes, as described next. Third, an entity that elects the expanded congestion coverage must schedule its external resources specified in external FTRs in the Day-Ahead Market to receive its congestion cost relief. Fourth, an entity that schedules such external resources in the Day-Ahead Market is not entitled to collect "congestion relief" LMP payments in the Real-Time Market. We will require that any congestion relief payments associated with schedule changes in the Real-Time Market of the lower of 10 percent or 50 megawatts will be refunded to the entity's external FTR account. We will also require the IMM to periodically evaluate this rule to determine its efficacy. Fifth, the Midwest ISO will guarantee that the net congestion charge associated with an external resource that follows such rules will be zero. Sixth, to the extent that the external FTRs held by an entity are insufficient to "pay" for the congestion charge associated with scheduling their eligible external resources, the Midwest ISO will make up the deficit through uplift charges. Conversely, to the extent that the external FTRs held by an entity have resulted in a surplus in the account, then the Midwest ISO can credit that surplus to those parties billed for the associated uplift, and if that is fully paid off, then any remaining surplus can be used to reduce other categories of uplift charges under the TEMT. Seventh, the holders of eligible external FTRs will nominate them and "hold" them for each year that the expanded congestion coverage is available, following which they will nominate such FTRs on the same terms as other Midwest ISO market participants. Eighth, any eligible FTRs created for longer than one year in the period that this coverage is available will also be eligible for these settlement rules for the years that they coincide.

93. The above rules are designed to provide parties on heavily congested areas with additional congestion coverage, yet allow them to participate in certain aspects of the FTR market for a learning period. These rules, however, are not intended to confer any financial advantages that could accrue from a perfect congestion hedge in the Day-Ahead Market. This accommodates Cinergy's concern that such a congestion cost hedge not result in unreasonable cost shifts to parties not receiving such a hedge.

94. We direct the Midwest ISO to file tariff sheets detailing the additional FTR guarantees for NCAs within 60 days of this order. Also, we direct the Midwest ISO to file tariff sheets setting out the uplift recovery and credit mechanism associated with the transition FTR process, including specification of the schedule through which uplift costs will be recovered, within 60 days of this order.

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

95. The Midwest ISO has proposed no mechanism to correct prices in the event of temporary market or system operational problems. For example, the Commission has approved for other ISO- or RTO-operated centralized dispatch markets 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 (such as telecommunications or hardware), or outages of generation or transmission equipment. That is, the Commission has approved means by which the ISO or RTO can correct prices that did not result from the proper application of the tariff. An example of such a rule is the NYISO "Temporary Extraordinary Procedures," which has evolved over the years in response to operational developments and Commission guidance.[84]

96. Stating such rules and filing them with the Commission reduces the need to rely on *ad hoc* measures when such temporary market or system operational problems occur. Given the scope of the Energy Markets and the complexity of its data and modeling tasks, such well-defined corrective authority is necessary to ensure just and reasonable prices in the market, particularly during the first months of operations. We will require the Midwest ISO to develop rules consistent with those previously accepted for other ISOs and RTOs and file them with the Commission no later than three months prior to the start of the Day 2 market. Such rules will 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.

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[84] 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. *See also* 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).

## C. Functional Responsibilities and Reliability

### 1. Allocation of Functional Responsibilities under the Day 2 Market

97. It is critical that the division of reliability functions between the Midwest ISO and control areas be clear. Without this clarity, the ability of the Midwest ISO and control areas to respond effectively to reliability emergencies will be compromised, and this would be true even in the absence of the TEMT, as shown in the Final Blackout Report. We consider the NERC-led effort to map reliability functions to be the best way to achieve the necessary clarity. In the TEMT Order, the Commission advised that the Midwest ISO and stakeholders adopt the NERC Reliability Functional Model (Functional Model) as a basis for discussions on the allocations of responsibilities for reliable market and power system operations.[85] The Commission also required that the revised TEMT "state clearly the current responsibilities under each of these categories and the proposed changes in those responsibilities."[86] We note here that the NERC Functional Model does not prescribe any particular organization or market structure.[87] That is, the functions are intended to be consistent with alternative market designs. Hence, we recognize that there is more than one way to implement the Functional Model to accommodate particular market designs.

#### a) The Midwest ISO's Proposal

98. Midwest ISO witness Joe Gardner states that the NERC Functional Model Version 2 was used as a "starting point to develop a model that more appropriately addresses the Midwest ISO's operational needs."[88] Following the NERC approach, the NERC-defined functions were assigned to responsible entities, although some entities share functions as

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[85] *See* TEMT Order at P 46. The NERC Functional Model Version 2 is the most recent iteration of NERC's ongoing efforts to define the set of functions that ensure reliability and are consistent with the changing structure and operations of the wholesale power markets. *See* NERC, NERC Reliability Functional Model, Function Definitions and Responsible Entities, Version 2, Prepared by the Functional Model Review Task Group, Planning Reliability Model Task Force, Approved by Standing Committees, November 11-13, 2003, Approved by Board of Trustees: February 10, 2004, *available at* www.nerc.com.

[86] TEMT Order at P 46.

[87] *See* NERC Reliability Functional Model at 6.

[88] Gardner testimony at 15.

necessary for Midwest ISO operations. Mr. Gardner further notes that the process of developing and adapting functional responsibilities "remains ongoing" but that the TEMT contains "sufficient detail" to define and describe responsibilities of these various entities in the Day 2 market.[89]

99. As described by Mr. Gardner, the entities defined in the NERC Functional Model do not exist today, which required assigning responsibilities in that model to existing entities, including the Midwest ISO, control area operators, Transmission Owners, Transmission Operators and Generation Owners.[90] Under the Functional Model, there are three primary roles with authority to carry out reliability functions: Reliability Authority, Balancing Authority and Interchange Authority.

100. As proposed in the TEMT, the Midwest ISO will be the Reliability Authority, which includes ensuring real-time operating reliability, performing transmission security analysis, approving generation and transmission outages, and performing regional and inter-regional coordination. The Midwest ISO and the control area operators will share the function of Balancing Authority. The Midwest ISO will determine the five-minute base-points, while the operators will undertake second-by-second balancing and have responsibility for maintaining regulation and operating reserves. Control area functions will be discussed in more detail in the next section. As Transmission Service Provider, the Midwest ISO will provide the function of Transmission Service. While the TEMT does not identify the Midwest ISO as Interchange Authority, it does identify it as the Interchange Scheduling Agent. The stand-alone NERC function of Market Operator is one of the areas in which the NERC Functional Model is evolving. As such, this is not a distinctly defined function in the TEMT, but the role is identified in the filing.

101. Other market participants will undertake the many operational and coordination roles prescribed in the Functional Model. For example, the transmission owners will be the Transmission Operators, while the owners of generation will be the Generation Operators and have responsibility for providing generation commitment plans and reporting annual maintenance plans to the Midwest ISO.

102. Under the proposed Day 2 market structure, control area operators have several types of responsibilities, including deployment of ancillary services, functions under their Balancing Authority role before and during the Operating Day, and non-market redispatch during the Operating Day.

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[89] Gardner testimony at 12-13.

[90] Gardner testimony at 12-13.

103. Consistent with responsibilities under NERC requirements, control area operators are responsible for ensuring adequate Regulation and Operating Reserves to meet the applicable NERC reliability standards. The control area operator coordinates the deployment of these ancillary services with the Midwest ISO and in accord with its procedures.

104. Balancing Authority functions prior to the Operating Day include compiling load forecasts from load-serving entities, implementing the generation commitment and dispatch instructions received from the Midwest ISO and acquiring ancillary services from Generation Owners. During the Operating Day, Balancing Authority functions include: (1) receiving the Resource base points for each Generation Resource sent to market participants, on a five-minute basis; and (2) receiving a ramped Net Scheduled Interchange[91] every four seconds that includes all scheduled interchange for that Balancing Authority, including Bilateral Transaction Schedules; (3) receiving from the Transmission Provider the amount of each Dynamic Schedule included in the dispatch calculation, to serve as confirmation to the Balancing Authority; (4) adjusting the Net Scheduled Interchange provided by the Transmission Provider by the real-time instantaneous dynamic signal; (5) sharing with the Transmission Provider the responsibility to direct Generation Owners and load-serving entities to take action to ensure energy balance in real time; (6) providing available real-time operational information to the Transmission Provider; (7) complying with reliability requirements specified by the Transmission Provider; (8) verifying implementation of emergency procedures with the Transmission Provider; (9) coordinating the use of controllable loads with load-serving entities (*i.e.*, interruptible load that has been bid in as an Ancillary Services); and (10) implementing Emergency procedures as directed by the Transmission Provider.

105. In addition, the control area operator has the ability during the Operating Day to redispatch the control area generation or reconfigure transmission to resolve transmission constraints on lower-voltage facilities that have not been turned over to the Midwest ISO and are therefore not modeled in the Midwest ISO State Estimator. The control area operators must provide such constraint information and resulting dispatch instructions to the Midwest ISO, which will then update the regional dispatch. Generators redispatched in this manner would be treated as self-scheduled and not eligible subsequently to set LMPs.

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[91] The Balancing Authority will use this Net Scheduled Interchange value in its Area Control Error equation.

106. In its transmittal letter, the Midwest ISO acknowledges that stakeholders have expressed concern about indemnification and allocation of costs associated with the new functional separation of responsibilities. The Midwest ISO notes that the functional separation is an appropriate modification of control area operators' responsibilities under NERC policy. The Midwest ISO states that it has not received detailed comments from stakeholders on specifics, and therefore has been unable to address these issues in the filing.[92]

107. Mr. Gardner notes that the Midwest ISO has evaluated the adverse impacts that could result from the proposed division of functional responsibilities and that the Midwest ISO intends to provide a "high degree of examination" over the activities of entities performing these functions.[93] No further detail on such oversight measures is presented.[94] Mr. Gardner further notes that control area operators serving as Balancing Authorities are not expected to modify dispatch instructions received from the Midwest ISO to favor particular generators.

108. The NERC Functional Model also prescribes a Planning Authority, the entity whose function is long-term planning for adequate and reliable resources and transmission within its area. This function is not accounted for in the proposed TEMT.

### b) Protests and Comments

109. A number of intervenors request clarification of the proposed functional responsibilities. AMP-Ohio requests more detail on the responsibilities of market participants and load-serving entities with regard to providing next-day load forecasts.

110. ATCLLC states that the proposed TEMT should recognize that stand-alone transmission owners and operators are now performing some functions that were traditionally considered control area functions. It states that the proposed tariff should be revised to reflect that.

111. Crescent Moon Utilities state that the proposed TEMT would be strengthened by a clearer distinction of the respective responsibilities of transmission owners and the Midwest ISO regarding control area operations and coordination. Further, the shift in control area operations should be undertaken slowly and with assurances of a smooth

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[92] *See* Transmittal Letter at 8.

[93] Gardner testimony at 25-26.

[94] Gardner testimony at 25-26.

transition. A number of protestors raise again the issue of regulatory and contractual authority to change functional responsibilities of entities within the Midwest ISO footprint.

112. Several intervenors request clarification and modification of the liability and indemnification 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. Cinergy states that "any entity following [Midwest ISO] reliability directives should be held harmless from reliability-related complaints filed at FERC and should be indemnified by [the Midwest ISO] for any civil lawsuits arising as a result of actions taken."[95] It adds that the limitation on liability and the indemnification for civil lawsuits should be spelled out in the TEMT.

113. Cinergy states that control area operators "must be ensured of recovery of costs incurred in complying with the new requirements under the proposed TEMT."[96] Cinergy proposes that an appropriate mechanism could be the development of ancillary service schedules for provision of related reliability functions not provided by the Midwest ISO.

114. A number of intervenors have comments on specific proposed functional responsibilities. For example, the manner in which the Midwest ISO and control area operators will arrange for provision of ancillary services and how this will affect the Midwest ISO energy markets. Other intervenors point to consolidation of control areas as a basis for improved reliability and market functioning.

115. Dominion, EPSA, First Energy, PSEG and Reliant argue that consolidation of control areas will improve system reliability. Dominion states that the Midwest ISO has ignored the Commission's instructions regarding control area consolidation. Under the distribution of functional responsibilities, Dominion claims that the Midwest ISO may not have the authority necessary to ensure short-term reliability, system security and exercise sufficient control over the ancillary service markets. In particular, the high volume of complex communications has the potential to lead to a control lag, poor and incomplete communications and market abuse. With respect to market abuse, Dominion and EPSA claim that control area operators have the opportunity to favor a particular market outcome or favor their affiliated interests in procurement of regulation and operating reserves.

[95] Cinergy at 61.

[96] *Id.* at 64.

116. Dominion requests that the Commission direct the Midwest ISO to submit a plan to reduce the number of control areas within 3 years; it argues that there should be two control zones, East and West.

117. The Midwest ISO TOs and Ameren state that Sections 38.6.3 and 38.6.8 should be rejected because they impose ancillary service obligations on control areas and independent transmission companies (ITCs) that should be borne by the RTO, per Order No. 2000 and other Commission precedent.[97] These parties also contend these provisions are unreasonable because they provide no compensation for the costs of acquiring ancillary services and are contrary to the GridAmerica ITC Agreement.

118. EPSA urges the Commission to direct Midwest ISO to modify the relevant tariff sections to require that either energy offers accepted for operating reserves in real time are included in the LMP calculation or that when operating reserves are deployed, the LMP will automatically be set at the offer cap for that hour.

119. Midwest TDUs have concerns that the TEMT affords control area operators discretion that can be used to their benefit. For example, Section 38.6.3 would appear to impose no limitations on resources that a control area operator may designate for regulation, and thereby avoid uninstructed deviation penalties, while third parties' self-supply of regulation is governed by the Midwest ISO's Business Practice Manuals.

### c) Discussion

120. As recommended in the TEMT Order, the proposed TEMT appropriately uses the NERC Functional Model as a basis for defining roles and responsibilities under the Day 2 market. The Functional Model clarifies how traditional responsibilities for reliability prior to electricity restructuring can be mapped into the operational requirements and industry structure that has emerged since.

121. The adaptation of the NERC Functional Model to the entities in the Midwest ISO region already shows the usefulness of the model. As Mr. Gardner discussed, there are 35 control areas and six different types of control areas. Therefore, as NERC recognizes, the term "control area" itself does not capture these evolving operational structures and, as shown by the Midwest ISO Functional Model, not all of the existing control areas will have the same functions under the Day 2 market.

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[97] *See* Central Hudson Gas & Elec. Corp., 88 FERC ¶ 61,138 at 61,399 (1999)

122. Reiterating our desire that the Midwest ISO adequately define the control areas' obligations and requirements,[98] the TEMT Order advised the Midwest ISO to provide clarification in the tariff of the respective obligations of the Midwest ISO and control areas. The proposed tariff states that, for ancillary service Schedules 2, 3, 5 and 6, unless the transmission customer makes alternative, comparable arrangements or the service is provided pursuant to an ITC Control Area Services and Operations Tariff, the Midwest ISO will obtain the service from the control area operator or pricing zone in which the load is located. The customer will pay the Midwest ISO for the ancillary service, and the Midwest ISO will pass through the revenues to the relevant control area operator or pricing zone. All eligible providers of such services are required by the Midwest ISO tariff to maintain their Commission-approved rates for service on the Midwest ISO OASIS. Energy Imbalance Service (Schedule 4) is provided through the Real-Time market and Scheduling Service (Schedule 1) is a direct pass-through of the control areas' costs. These schedules make clear that the Midwest ISO is the provider of all the ancillary services, but that the Midwest ISO will acquire them from ancillary service providers and pricing zones. We remind the Midwest ISO that we have previously ordered it to file an expected timeframe for the implementation of markets for regulation and operating reserves.[99] We direct the Midwest ISO to include this timeline in its compliance filing due 60 days after the date of this order. Since there is no reserves market in the Midwest ISO at this time, we decline to implement EPSA's recommendations. We believe progress toward development of a reserves market will address the control area operator and pricing concerns that EPSA raises.

123. Cinergy raises valid concerns over the potential for unrecovered costs due to the switch to the NERC Functional model. The Commission recently determined that "limited liability provisions may be appropriate for inclusion in Commission tariffs under certain circumstances," and conditionally accepted such a provision for the Midwest ISO.[100] We note that liability issues have arisen in the investigation of the August 14, 2003 blackout, and we intend to fulfill the recommendations of that investigation. As directed below, we will require the Midwest ISO and the Transmission Owners to participate in a settlement judge conference to address these and other issues.

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[98] *See* Declaratory Order at 61,547.

[99] *See* Midwest Independent Transmission System Operator, Inc., 103 FERC ¶ 61,210 at Ordering Paragraph C (2003).

[100] Midwest Independent Transmission System Operator, Inc., 100 FERC ¶ 61,144 at P 24 (2002).

124. As expressed most recently in the TEMT Order, we support consolidation of control area operations.[101] In that order we requested an evaluation of progress towards this goal within one year of Day 2 market start-up.[102] Given the extraordinary effort of Day 2 implementation and our interest in maintaining sufficient redundant control area capabilities for safeguards at the start of the Day 2 market, we will not require Midwest ISO to return to this issue until after the start of the market. At that time, we will require the Midwest ISO to establish a dialogue with stakeholders on consolidation of control areas, with the express purpose of significantly reducing the number of control areas and eventually consolidating most control area functions in the Midwest ISO. We will require the Midwest ISO to file a progress report on this process no more than 12 months after the start of the Day 2 market.[103] This report must specifically address the Midwest ISO's ability to ensure short-term reliability and must define how the Midwest ISO retains independent control of the transmission grid and generator dispatch when individual control areas can redispatch the control area generation or reconfigure transmission to resolve transmission constraints.

125. The Midwest ISO TOs consider Section 38.2.4 unreasonable because it requires market participants that withdraw from membership in the Midwest ISO to continue to follow the Midwest ISO's dispatch instructions. We consider it an appropriate condition of service under the TEMT that generators must accept the Midwest ISO redispatch signal in limited circumstances. Specifically, to clarify this condition of Midwest ISO service, we direct the Midwest ISO to revise this provision to state that it applies to redispatch only in emergency situations. We believe such authority is appropriate regardless of whether generators belong or previously belonged to the Midwest ISO.

126. Finally, we will require the Midwest ISO to further define in the tariff its role as Planning Authority, a function that is discussed in its testimony but not in the proposed TEMT.

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[101] TEMT Order at P 42, 50.

[102] *Id.* at P 50.

[103] *See* Midwest Independent Transmission System Operator, Inc., 103 FERC ¶ 61,210 at P 38 (2003).

### 2. The Midwest ISO's Legal and Regulatory Authority to Clarify the Allocation of Functional Responsibilities

#### a) The Midwest ISO's Proposal

127. The TEMT proposes that a control area operator shall "perform those reliability functions necessary to operate its Control Area within the requirements established by NERC and the Control Areas' associated Regional Reliability Council."[104] The Midwest ISO also proposes that all control areas within the Midwest ISO region shall function as a centrally coordinated system and shall operate pursuant to a single set of dispatch instructions that the Midwest ISO determines and provides.[105] In this regard, as described above, the Midwest ISO proposes to assert new authority over some operations in its footprint. Specifically, the Midwest ISO will perform reliability functions that individual control area operators have performed in the past.

128. The Midwest ISO proposes a limited number of changes to the Transmission Owner Agreement to effectuate the proposed changes. It seeks to amend Appendix E of the Transmission Owners Agreement to state that the Midwest ISO, Transmission Owners and transmission users shall be responsible for the operational functions defined in Appendix E of the Transmission Owners Agreement, and the TEMT shall prevail if there are discrepancies between it and the Transmission Owners Agreement.[106] The Midwest ISO also proposes to add to the Transmission Owners Agreement that it is responsible for the functions and responsibilities defined in the TEMT in its role as the Reliability Authority, Market Operator, Interchange Scheduling Agent and Balancing Authority.[107] Finally, the Midwest ISO proposes to specify that owners and users shall be responsible for administering the functions defined in the TEMT in their roles as Balancing Authorities, Market Participants, Transmission Service Providers and Transmission Operators.[108]

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[104] Module C, Section 38.6, Original Sheet No. 427.

[105] Module C, Section 38.6, Original Sheet No. 428.

[106] Transmission Owners Agreement, Appendix E, Section I, First Revised Sheet No. 149.

[107] Transmission Owners Agreement, Appendix E, Section I(A)(9), First Revised Sheet No. 150.

[108] Transmission Owners Agreement, Appendix E, Section I(B)(8), First Revised Sheet No. 152.

### b) Protests and Comments

129. The Midwest ISO TOs and Alliant request, separately, that the Commission reject Section 38.6 in its entirety. They argue that the Midwest ISO should have negotiated contracts with the control areas to provide the Midwest ISO with the necessary authority. The Midwest ISO TOs and Alliant add that the Commission does not regulate entities with regard to the provision of control area functions, because voluntary standards for such functions are set by NERC.

130. The Midwest ISO TOs and Alliant also argue that the Midwest ISO lacks contractual authority to direct control area operators to implement the Energy Markets. They argue that the Transmission Owners Agreement provided the Midwest ISO with authority with regard to transmission scheduling and as security coordinator, but that it did not contemplate energy markets or centralized dispatch over the Midwest ISO.[109] In the absence of contractual authority, the Midwest ISO TOs and Alliant argue that the Midwest ISO cannot include provisions such as Section 38.6 in the TEMT. They aver that it would have been consistent with the TEMT Order for the Midwest ISO to have entered into agreements with the control areas to acquire these rights. Had the Midwest ISO negotiated such agreement, argue the Midwest ISO TOs, it could have addressed individual control area operators' issues, such as cost and liability.

131. Cinergy believes that the Midwest ISO lacks the authority to claim centralized control area authority unilaterally. It states, however, that it will accept the Midwest ISO's proposal under three conditions: (1) the Midwest ISO must demonstrate that it is capable of assuming reliability functions, and coordinating the reliability functions for which it proposes to assume authority to direct control areas' actions; (2) if the Midwest ISO takes control of reliability functions, Cinergy and other transmission owners and operators should be held harmless from reliability-related complaints filed with the Commission, and indemnified for civil lawsuits arising out of actions taken at the Midwest ISO's direction; and (3) control area operators must be ensured of recovery of costs incurred in complying with new requirements under the TEMT.[110]

132. Ameren argues that Section 38.6.1 would provide the Midwest ISO with broad authority to direct control areas for non-emergency purposes. It argues that this provision conflicts with the GridAmerica ITC agreement, under which the Midwest ISO may

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[109] Midwest ISO TOs at 11-14 (citing Transmission Owners Agreement Appendix E, Section I(A); Formation Order at 62,128); Alliant at 13 (citing Transmission Owners Agreement Appendix E, Section I(A); Formation Order at 62,156).

[110] Other sections of this order discuss the conditions Cinergy requests.

exercise only the functional control enumerated in Schedule 5. Ameren alleges that Schedule 5 of the GridAmerica ITC Agreement does not grant the right to direct control area operations, and that this would conflict with the recommendation in the Final Blackout Report that NERC and the regional reliability councils remain independent of the entities they oversee.[111] Ameren suggests that the Commission require the Midwest ISO to negotiate change to these arrangements.

133. EPSA argues that the control of all essential and transmission-related operations and market functions must be brought under centralized, independent authority as soon as possible. It cites the Final Blackout Report's discussion of "institutional complexities" among entities with reliability-related responsibilities as a contributing factor to the blackout, and the Final Blackout Report's subsequent finding that decentralization of control is undesirable.[112] EPSA notes that while the Midwest ISO will exercise centralized oversight over particular functions, the individual control areas will retain substantial autonomy with respect to procurement of ancillary services and reliability-related matters. EPSA asks the Commission to reject any assumption that the definition and allocation of responsibilities in the NERC Functional Model is an acceptable end-state alternative to consolidation. It is concerned that the Midwest ISO "is merely shifting from one form of multi-layered complexity to another, and that, in fact, NERC's Functional Model provides incomplete guidelines for addressing the multiple control area dilemma."[113] EPSA urges the Commission to direct the Midwest ISO to expedite its discussions with control area operators and provide the Midwest ISO and the existing control area operators with: (1) specific guidelines on what the Commission considers "control area consolidation" to be; and (2) a date certain by which such control area consolidation must occur.

134. In its Answer, the Midwest ISO states that it has carefully considered and reviewed the requirements of Order No. 2000, the Commission's orders approving the Midwest ISO's operation as an RTO, Commission orders regarding similar issues in other RTOs and ISOs, and the Commission's guidance in response to the Midwest ISO's development of an energy market. The Midwest ISO believes that the elements of the

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[111] *See* Ameren at 9 (citing Final Blackout Report at 143). The Blackout Report notes that NERC is funded by dues that market participants pay to the regional reliability councils. The Blackout Report finds that this makes NERC subject to the influence of the control areas and other members. Final Blackout Report at 143.

[112] *See* EPSA at 8-9 (citing Final Blackout Report at 14, 17-22, 146.

[113] *See id.* at 11.

TEMT represent "an appropriate application of Commission direction and precedent under the Federal Power Act, and are supported by the authority granted the Midwest ISO under the [Transmission Owners] Agreement."[114] The Midwest ISO acknowledges that the TEMT includes controversial elements, but states that those elements arise from the Midwest ISO's unique circumstances – specifically, its diverse footprint and lack of experience operating as a tight power pool. Citing the TEMT Order, the Midwest ISO argues that the TEMT is consistent with its authority as an RTO and the flexibility that the Commission has provided it in prior orders.

### c) Discussion

135. The reallocation of functions that the Midwest ISO proposes are critical to reliability in the Midwest ISO region. The IMM has observed in its past two Annual Reports that developing Day 2 markets, such as those proposed here, would, among other things: (1) provide efficient long-term economic signals for investment and retirement of generation or transmission facilities (through the Resource Adequacy requirement); (2) allow the use of "latent" reserves on generating units that are not fully dispatched; and (3) through FTRs, provide for market-based transmission investment.[115] The Midwest ISO stated in its 18-month report that these improvements will provide reliability benefits as well as economic benefits.[116] The IMM's 2003 report added that central dispatch would not only send more efficient price signals, it "allows the transmission network to be more fully utilized and increases the RTO's control over network flows."[117]

136. The Blackout Report noted that after the August 14, 2003 blackout, NERC required the Midwest ISO to reevaluate its operating agreements with member entities to verify its authority to address operating issues, including voltage and reactive

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[114] Midwest ISO Answer at 9 (citing Commission orders).

[115] *See* Potomac Economics, Ltd., 2002 State of the Market Report: Midwest ISO at 49-51 (2003), *available at* www.potomaceconomics.com/serv01.htm.

[116] *See* 18-Month Operational Assessment Report at 6, Docket No. ER98-1438-000 (Aug. 1, 2003) ("The ability to monitor and manage the entire grid, or as large a portion as possible, enhances the reliability of the System by providing the capability to mitigate or prevent undesirable consequences associated with the impact of inter-related events.").

[117] Potomac Economics, Ltd., 2003 State of the Market Report: Midwest ISO at 51 (2004), *available at* www.potomaceconomics.com/serv01.htm.

management and the ability to direct actions during system emergencies.[118] The U.S.-Canada Task Force also recommended that NERC require any problems or concerns relating to these operational issues to be raised promptly with the Commission and the Midwest ISO's members for resolution.[119] The NERC Audit Report notes that it was unclear at the time of the (post-blackout) audit "if the contractual agreement between MAPPCOR and its members adequately establishes the authority of the Reliability Coordinator whether performed by MAPPCOR or" the Midwest ISO. The Audit Report suggests that the Midwest ISO document its authority to fulfill all Reliability Coordinator functions as defined by NERC and the Regional Reliability Councils, and that it confirm that the control areas within its footprint concur with this authority.[120] The Midwest ISO's proposals here can be understood to respond to these recommendations.

137. There are, however, a number of unresolved issues surrounding the proposal. It is unclear precisely what the functional responsibilities of the Midwest ISO and the control areas will be, and how they will work together to effectuate the new arrangements. Cinergy and the Midwest ISO TOs also raise valid concerns about the costs and liability obligations that will be associated with the Midwest ISO's and the control areas' new roles, and those issues should be addressed concurrently with the details of the new proposal. We note that the Midwest ISO is a non-profit organization, and that any liabilities imposed on the Midwest ISO may be recovered through uplift.

138. The Commission's experience in other RTOs and ISOs has been that resolution of issues like these through negotiation is preferable to resolution by litigation. We therefore direct the Midwest ISO and the Transmission Owners 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. The parties are directed to make a filing within 60 days of the date of this order, presenting a proposed resolution. They may seek the assistance of the Commission's dispute resolution staff for this process.

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[118] *See* Blackout Report at 153.

[119] *See id.*

[120] *See* Audit Report at 13.

## D. *Financial Transmission Rights and Locational Marginal Pricing*

139. The Midwest ISO proposes to provide FTRs to hedge congestion charges in the Day-Ahead Market. FTRs will be specified as obligations initially, and, when feasible, also as options; other specifications include the receipt and delivery points (each point may be a node, hub, load zone or interface), the quantity (one FTR is equal to one megawatt), the FTR period (peak/off-peak), and the term (month, season, year). FTRs will be allocated to eligible entities as part of the conversion of existing OATT network and point-to-point service to TEMT transmission service. As proposed, the allocation methodology guarantees that at least base-load resources will receive full FTR coverage, but that FTRs to cover intermediate and peaking resources may be pro-rationed. The allocation period is one year. During that year, new FTRs can be awarded for network upgrades and FTRs may also be terminated due to retirement of generation resources. Each month during the allocation period, the Midwest ISO will hold an FTR auction where transmission capability not subscribed by FTRs can be bought and where existing FTRs can be bought and sold. In addition, load shifts in states with retail choice programs can be followed during the month through the assignment to competitive retail suppliers of Auction Revenue Rights (ARRs) for the monthly auctions. Also, each month, the Midwest ISO will pay holders of FTRs using congestion revenues collected, including surplus congestion revenues, but will pay holders of FTRs on a *pro rata* basis if such congestion revenues are not adequate.

140. The following sections examine issues in the proposed allocation methodology – first the general method, then other issues, including measures that can provide greater certainty that FTRs will be sufficient to hedge day-ahead congestion charges. Next, the illustrative FTR allocation conducted by Midwest ISO will be addressed. Finally, several other FTR issues not related to the initial allocation are examined.

### 1. General Methodology for Nomination and Allocation of FTRs

#### a) The Midwest ISO's Proposal

141. The Midwest ISO proposes to directly allocate FTRs to existing users of the transmission network. The TEMT sets out a "compromise proposal" for the annual allocation, developed in consultation with stakeholders and with substantial input from OMS. The compromise would allow parties to freely nominate FTRs between their eligible points of delivery and receipt. However, all parties remain able to receive a full allocation of nominated FTRs from resources they use to serve baseload (with criteria to determine baseload). To the extent that this full allocation is not achieved in the flexible phase of the allocation, counterflow FTRs will be assigned (either to parties providing

existing transmission service or to the system as a whole) to ensure that the baseload FTRs are "restored." This restoration process is described further below.

142. The TEMT proposes to initiate the FTR allocation process for existing and new market participants at least ninety days prior to the beginning of each allocation period. All existing OATT service and holders of GFAs that convert to FTRs are required to register their existing entitlements (terms of service, capacity reservation, OASIS reservation numbers) for conversion to FTRs.

143. FTRs can be nominated from Network Resources based on the Forecast Peak Load served under Network Integration Transmission Service and from the points of delivery and receipt in Point-to-Point Transmission Service of annual duration or longer. The maximum quantity eligible for nomination is the sum of these existing entitlements for network service and the total quantity in each point-to-point service. The FTR allocation process takes place over four successive and cumulative tiers. In each tier, a Market Participant is allowed to nominate up to a percentage of its maximum nomination eligibility less the FTRs awarded in the prior tier. The cumulative Tier Factors are: Tier I, 35 percent; Tier II, 50 percent; Tier III, 75 percent; and Tier IV, 100 percent.

144. The transitional restoration process defined in the TEMT will be in place for 3 years. Any eligible FTRs that were pro-rationed in the first two tiers are eligible to be restored. Eligibility requires that if the nominated FTR is from a network resource, that network resource has an average historical capacity factor of at least 70 percent, and if the nominated FTR is to convert existing point-to-point service, that service has a historical scheduling factor of at least 70 percent. To restore the pro-rationed FTRs, the Midwest ISO will define Counter Flow FTRs sufficient to make the eligible nominated FTRs simultaneously feasible. Counter Flow FTRs are defined as eligible base-load FTRs that were either not nominated by a Market Participant or not awarded in the first two tiers, but that if they were assigned would provide counterflow in the FTR model for restoration of other nominated FTRs. The Midwest ISO will choose the minimal set of Counter Flow FTRs needed for restoration. The Counter Flow FTRs are allocated directly to the Market Participant that was eligible to nominate them. They will be settled like other FTRs, except in the event of a unit outage, in which case they will not be settled (that is, if the unit is not physically available to provide counter flow, it won't be held financially responsible). Any resulting shortfall in congestion revenues will reduce payments to FTR holders on a pro-rata basis.

#### b) Protests and Comments

145. Commenters on the proposed allocation methodology address the policy objectives for FTR coverage, alternative methods to achieve those objectives, and details of the proposed procedures. There are two basic perspectives on the policy objectives for FTR allocation. On the one hand, a number of parties believe that the Midwest ISO

proposal, because it likely results in some degree of pro-rationing of FTRs, does not sufficiently convert existing physical transmission service into equivalent financial rights.[121] These parties seek some degree of additional mandatory FTR assignment based on historical uses or alternative safety nets. Their overarching policy goal is to financially "hold harmless" existing transmission customers with respect to the transition to the Midwest ISO Day 2 market. On the other hand, there are those parties that advocate a voluntary nomination of FTRs between eligible points, regardless of the potential pro-rationing to other parties.[122] They would retain the basic structure of the proposed Midwest ISO method, but reject the mandatory obligations imposed under the "restoration step."

146. There is little dispute among intervenors, and the Midwest ISO, that the proposed FTR allocation methodology, including the restoration step, will result in some pro-rationing. There is also little dispute that the remaining uncertainty over FTR modeling makes it difficult to resolve how much pro-rationing will ultimately result. For example, the Midwest TDUs put forward several reasons why the proposed restoration process will not be sufficient to provide a complete hedge for existing transmission service. First, they argue that since the Midwest ISO will only establish counterflow FTRs where an existing counterflow usage from a baseload resource can be identified, FTR nominations will still be subject to pro-rationing when such uses cannot be identified. Second, some existing transmission service was granted using power flow models that assumed that peaking units were operating and thus providing counterflow. The Midwest ISO method will not capture this counterflow for restoration purposes. Third, only existing transmission service from units with a year-round capacity factor of 70 percent are eligible for restoration. Fourth, because of the backward-looking (historical) test to determine capacity factors, some resources that were not eligible based on past year output could be back in service as baseload in the coming year. Fifth, the Midwest ISO's application of the 70 percent usage factor for external resources involves examining the network load's overall load factor rather than the capacity or delivery factor of the particular external resource. This could degrade the existing network service rights of particular TDUs.

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[121] These parties include Alliant, American Forest & Paper Association, Crescent Moon Utilities, Great Lakes, Midwest TDUs, Minnesota Entities, NRECA, OMS, PSEG, Southwestern, WPPI, WPS Resources, WUMS Load Serving Entities and Xcel.

[122] Cinergy and Otter Tail.

147. OMS also argues that the Midwest ISO restoration proposal is not sufficient to protect existing transmission customers. The OMS Board of Directors adopted the following five principles for FTR allocation, restoration and uplift processes: (1) hold harmless, such that existing transmission customers do not have to pay for additional congestion costs compared to what they would have paid if the market structure had not changed; (2) enforceability, such that the allocation methodology ensures the hold harmless principle; (3) eligibility, such that any pro-rationing that results in an existing transmission customer being harmed, the pro-rated FTRs would be eligible for restoration; (4) restoration process should reflect present-day financial outcomes for holders of existing firm transmission service, to the extent that such service does not embody enduring cost shifts caused by others;[123] (5) the assignment of counterflow FTRs for purposes of restoration should be limited to three years; and (6) a safety net should be provided such that if base case restoration cannot be achieved under simultaneous feasibility but the existing transmission customer is subject to significant financial harm, then methods of uplifting the costs of restoration should be used. OMS supports the basic approach of the proposed TEMT allocation methodology. However, it finds that while the proposed methodology meets principles 3, 4, and 5, it does not meet principles 1, 2, and 6.

148. To address its remaining principles, OMS recommends three additional *ex ante* and *ex post* safety-net components for the TEMT such that the objective to keep existing transmission customers whole is met.[124] First, *ex ante* criteria should be established to determine whether the FTR allocation process results in harm to a transmission customer. These criteria should address how harm will be measured and over what period of time, and the existing level of congestion costs that should be included. Second, a process of FTR restoration should be included that eliminates such harm without resulting in harm to others. Third, the TEMT should include a provision to uplift the possible revenue inadequacy resulting from such additional restoration.

149. OMS recommends that an alternative approach could be an "ex post procedure to determine after the fact if a transmission customer did not have an opportunity to receive an FTR allocation that reflects risk equivalent to its existing firm rights."[125]

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[123] This statement reflects our understanding of OMS's comments.

[124] OMS at 18.

[125] OMS at 18.

150. OMS recognizes that broader safety nets involve shifting costs from one party to another and proposes that the Midwest ISO establish a working group to develop the details of its proposals and to submit the proposals to the Commission prior to the initial allocation of FTRs. The OMS proposes several measures that this working group could consider, which are discussed in the next section.

151. Other parties recommend extending the degree of FTR coverage that the Midwest ISO provides by modifying the allocation methodology to include mandatory assignment of FTRs up to some level of historical use. Midwest TDUs and WPPI propose that in addition to base-load resources, such mandatory assignment should also cover transmission service to intermediate and if possible peaking resources with existing transmission service. WPPI proposes a rule that the Midwest ISO should be restricted to pro-rating the total FTRs awarded to an entity for base-load and intermediate resources to no more than 5 percent.

152. Several intervenors protest the proposed FTR restoration process. Cinergy, with support from Otter Tail, argues that mandatory assignment of counterflow FTRs is not just and reasonable because it imposes unwarranted financial obligations on the party that receives them.

153. In contrast with parties seeking greater degrees of mandatory assignment to cover historical uses, Cinergy, with support from Otter Tail, proposes adopting a methodology for flexible FTR nomination, with some modification, that it earlier introduced in the Midwest ISO stakeholder process. Under this proposal, entities can nominate FTRs between any eligible points that they choose in each of the Midwest ISO's four tiers. Cinergy argues that this voluntary nomination approach is analogous to PJM's method of direct FTR allocation, in which FTRs were assigned based on historical uses, but entities were allowed to reject FTRs thus assigned. Finally, Cinergy requests that the proposed Midwest ISO restoration process be rejected but state commissions would be allowed to restore pro-rated FTRs if such requests are accompanied by instructions as to how the uplift is allocated.

### c) Discussion

154. We will accept the TEMT FTR Allocation methodology, with modifications (and with the additional measures presented in section IV (B)).

155. We recognize that the proposed allocation method reflects an attempt at a compromise between advocates of flexibility in the allocation, such as Cinergy, and advocates of approaches that stress mandatory allocation based on historical uses. The proposed restoration step, designed to allow for flexible nomination to the extent that it does not conflict with entities nominating baseload FTRs that were historically feasible, is an innovative solution (despite the recognition by all parties, including the Midwest

ISO, that the assignment of counterflow FTRs is complex and requires arbitrary decisions that have external effects on the distribution of FTRs). As such, the Midwest ISO proposal, reflecting OMS's efforts, is a valuable effort.

156. In the Declaratory Order, the Commission stated that the primary objective of the initial FTR allocation is "to hold existing transmission customers whole with respect to congestion related charges under [Midwest ISO] Day 2 operation to the extent possible given the objective of simultaneous feasibility."[126] Moreover, the Commission stated that it "continue[d] 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."[127] The Commission noted 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. Hence, the order noted that the Commission "expect[ed] that Midwest ISO's tariff will clearly indicate that the selection of Candidate FTRs is based on historic uses of the system."[128] We agree with OMS that with some additional safeguards, our objectives and principles for the FTR allocation can be achieved through the proposed Midwest ISO methodology. Hence, we will augment the proposed FTR allocation methodology with additional measures to ensure that market participants receive sufficient FTRs and are able to adjust their FTR portfolios based on a few months of market experience. These measures are discussed in the next section.

### 2. Other Issues Related to the FTR Allocation Process

#### a) The Midwest ISO's Proposal

157. This section addresses protests and comments seeking to modify the Midwest ISO's proposed FTR allocation methodology and implementation schedule.

158. The Midwest ISO will initiate the process to allocate FTRs at least 90 days prior to the beginning of each allocation period. As noted above, Midwest ISO proposes that Transmission Customers qualified as market participants with firm transmission service, whether Network Integration Transmission Service or Point-to-Point Transmission Service, can nominate FTRs on an equal basis. However, in each tier, an entity is allowed to nominate up to a percentage of the total MW represented by network service for forecast peak load, but only up to that percentage of the reservation MW quantity for

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[126] Declaratory Order at P 64.

[127] *Id*.

[128] *Id*. at P 65.

each point-to-point service entitlement. The TEMT allows that for transmission service in which the points of receipt are a Control Area, the existing entitlement can be defined in terms of generation nodes, load zone nodes or a hub. If the parties to the existing contract can not determine the appropriate set of receipt nodes, the Midwest ISO will define them as a *prorated* share of each generation node. In the tier nomination rules, pumped storage units are given the option to nominate for peak or off-peak FTRs in Tier I, whereas in that tier all other resources designated as source points must nominate for both peak and off-peak. The option to nominate peak or off-peak FTRs becomes available for all resources in Tier II and after.

159. The TEMT provides rules for determining the historical period in which the capacity and scheduling factors will be calculated.[129] For network resources, data from the previous 60 months will be examined. Over this period, the 12 consecutive months with the lowest capacity factor will be excluded. However, if there is less than two years of available data, then all data will be used (that is, none is excluded) and if there is less than six months of data, then the resource is not eligible for restoration. Similarly, point-to-point service with less than six months of scheduling data will not be eligible for restoration, and in determining the scheduling factor, from six to 24 months of data will be examined.

160. The TEMT defines an alternative process for FTR restoration (henceforth, "alternative process") under which a state commission can institute remedial procedures to restore curtailed FTRs.[130] Such requests must be accompanied by instructions from the state commission regarding how the required Counterflow FTRs, or their costs (*i.e.*, uplift), are allocated among market participants under the state commission's jurisdiction. This restoration process is not subject to a transition period. The TEMT allows that "this process will be available at the discretion of each state and is subject to Commission approval."[131] Moreover, the TEMT allows for state commissions to propose remedial actions (henceforth, "remedial actions") on behalf of jurisdictional market participants that are dissatisfied with their FTR allocations. If the state commission proposes a remedy to the Midwest ISO, it also "shall file such proposal with the Commission for approval."[132]

[129] Module C, Section 43.2.5.d, Original Sheet Nos. 628-29.

[130] Module C, Section 43.2.6, Original Sheet No. 630.

[131] Module C, Section 43.2.6, Original Sheet No. 630.

[132] Module C, Section 43.7.3, Original Sheet No. 648.

### b) Protests and Comments

161. A first category of protests and comments addresses whether the FTR conversion rules fairly accommodate various types of existing transmission service and current transmission reservation requirements.

162. Several intervenors argue that under the proposed rules, network customers have advantages over point-to-point customers, or vice versa, and that holders of short-term rights, which often include competitive suppliers in retail choice states, are unduly disadvantaged in the allocation with respect to holders of longer-term rights.

163. AMP-Ohio argues that point-to-point customers are restricted in each tier to percentage nominations between each of their particular eligible points of delivery and receipt, which under some circumstances would limit their ability to nominate compared to a network customer nominating for the same path. AMP-Ohio requests that point-to-point customers be allowed to aggregate their total reservation quantity by sink and assign percentages voluntarily among paths to the sink.[133]

164. Several intervenors argue that holders of transmission service with a duration of less than one year should be eligible for FTRs through the allocation. EPSA and Strategic argue that in retail choice states, competitive retail suppliers have bought monthly point-to-point service rather than annual, to reflect the frequent changes in the load that they serve. EPSA and Strategic claim that the Midwest ISO's proposal disadvantages such holders of short-term service.[134] Dominion argues that competitive retail suppliers are disadvantaged under the FTR allocation priority given to utilities with base-load generation and load. Dominion claims that in the illustrative allocation it received no FTRs despite having existing load obligations.[135] Detroit Edison argues that network service that is in use for an FTR season should be eligible to nominate an FTR for that season.[136]

165. Several intervenors have concerns about conversion of rights to roll over existing firm transmission service. Cinergy and Detroit Edison argue that because the rules for rolling over rights and the period of nomination for the FTR allocation are not

[133] AMP-Ohio at 18-20.

[134] EPSA at 15-17.

[135] Dominion at 15-17.

[136] Detroit Edison at 21.

coordinated, entities will have to nominate FTRs before finally deciding whether to exercise their roll-over right. They request that these rules be clarified so that entities are not penalized for changing their decision within the roll-over window (e.g., by having to hold obligation FTRs that they do not need).[137] In contrast, WPPI argues that it is unjust and unreasonable to treat short-term transmission reservations (one to three years) with roll-over rights equivalent with long-term transmission rights and network resource designations. They request that the latter receive priority in the allocation in the event that pro-rationing of FTRs is required.

166. Great River requests a tariff rule to account for conversion of "transitional" transmission reservations: those that are confirmed before the effective date of the tariff, but for which transmission service does not start until after the Day 2 market begins.[138]

167. A second category of protests and comments addresses particular types of contracts or resources that may be difficult to represent adequately in FTR nominations. Midwest TDUs argue that the proposed FTR allocation creates problems for converting existing transmission service for system purchases, which are used extensively by small systems.[139] In converting a system purchase, the transmission customer will have to designate a set of source nodes. Midwest TDUs are concerned that it will not be possible to arrange an exact match between generation resources and transmission paths, thus possibly resulting in congestion charges in excess of FTR revenues. They suggest that Midwest ISO adopt a method used in PJM, under which FTRs can be defined from a supplier's hub to the buyer's load node(s). They recommend that the seller of the system power would then be responsible for the congestion charges from the resources to the hub. Alternatively, if the proposed nomination method is approved, but the Midwest TDUs request that the Commission require the Midwest ISO to provide guarantees that the holder of the system purchase contract is held harmless from any unhedged congestion charges.

168. Detroit Edison argues that the proposed FTR allocation fails to provide it with transmission rights equivalent to current rights for its Ludington pumped storage facility. Detroit Edison notes that peak/off-peak differentiation in FTRs is not sufficient to hedge Ludington, because the unit sometimes pumps during peak hours and generates during

[137] Cinergy at 16; Detroit Edison at 23-25.

[138] Great River at 13.

[139] Midwest TDUs at 67-68.

off-peak hours. It claims that "bi-directional" FTRs would be needed to properly hedge the pumping and generating modes of pumped storage and requests that Midwest ISO allocate such rights.

169. A third category of protests and comments addresses the proposed rules that determine eligibility for restoration and the duration of the restoration procedure. Several parties argue that the capacity factor requirement for eligibility for FTR restoration is too restrictive. Midwest TDUs urge that the proposed rules defining the historical period for evaluation of a resource's capacity factor be modified, to establish a process for the Midwest ISO to evaluate requests by utilities that change resources over any period longer than six months prior to the allocation deadline to demonstrate what the relevant period is for the historical analysis. Midwest TDUs state that this is particularly important for smaller utilities, for which megawatt changes in use of one resource may significantly change the usage of other resources, to qualify for sufficient restoration.[140] Specifically, they propose that such evaluation could be limited to resources that supplied at least 10 percent of a market participant's annual energy requirement and had a capacity factor of at least 50 percent in the prior 12-month period. AMP-Ohio also requests that the Midwest ISO reflect changes in resources use more accurately by applying greater weight in the historical analysis to the prior year and reservations for the next year.[141]

170. IMEA and Midwest TDUs protest the termination of FTR restoration after three years. They note that some existing transmission rights last for much longer periods. IMEA argues that there is no reason given for this termination and that there should be no such limit.

171. A fourth category of protests and comments addresses additional measures in the specification of FTRs and the sequencing of the annual FTR allocation that would improve the coverage of awarded FTRs.

172. Midwest TDUs argue that the proposed term for FTRs does not fully account for temporal diversity among firm uses.[142] OMS encourages Midwest ISO to consider allowing nomination of monthly FTRs, peak and off-peak, in Tiers 2, 3 and 4 as soon as possible.[143]

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[140] Midwest TDUs at 75-77.

[141] AMP-Ohio at 20-21.

[142] Midwest TDUs at 69.

[143] OMS at 18-19.

173. OMS encourages the Midwest ISO to issue counterflow flowgate rights (FGRs) corresponding to the megawatt capacities of assumed loop flows within its footprint.[144] WUMS Load-Serving Entities propose and seek clarification that under the alternative process, in the event that parties within a state request additional FTRs for Network Resources with source points and sink points within the state, they can choose to allocate either Counterflow FTRs or flowgate rights for the purpose of simultaneous feasibility.[145] If they choose to use FGRs, then the Midwest ISO shall make available shadow pricing to permit such use.

174. OMS further encourages the Midwest ISO to allow transmission customers nominating base-load FTRs that are not awarded through restoration to accept counterflow flowgate rights if such rights reduce harm to the customer.[146]

175. Crescent Moon Utilities, FirstEnergy and Great River urge the inclusion of FTR options at the start of the Day 2 market. FirstEnergy proposes an auction with FTR options prior to the market start and also requests that the Commission establish a firm deadline for implementation of FTR options.

176. To provide a further check on the initial allocation (and also partly to address the concerns of stakeholders who prefer additional illustrative allocations), Alliant, Detroit Edison and Ohio Commission and the OMS recommend that the initial FTR allocation should be performed for an entire year, but only be valid for a short period. OMS proposes (based on the Day 2 implementation schedule prior to the Procedural Order)

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[144] OMS at 18-19.

[145] WUMS Load-Serving Entities at 40-41. A flowgate right, as defined here, is a financial transmission right associated with a particular transmission element (which can be called a flowgate). It is modeled in the FTR allocation as megawatt capacity reserved on that element. (In contrast, a point-to-point right is modeled as transmission capacity on all lines that would carry flow between the point of injection and the point of withdrawal.) FGRs are settled on the basis of the shadow price on the transmission element with which they are associated. When the element is not congested, the shadow price is zero; when it is congested, the shadow price is greater than zero. Although it is not proposing to allocate FGRs, the Midwest ISO will be calculating those shadow prices in the course of its Day-Ahead and Real-Time Markets. As OMS proposes, such rights can be used for counterflow purposes in the FTR allocation.

[146] OMS at 18-19.

that the first initial annual allocation would be valid for six months (from December 1, 2004, to May 31, 2004). Based on the experience with the market, a new nomination would then take place, resulting in a second initial allocation for the twelve months beginning June 1, 2005. From then onwards, the annual FTR allocation would run from June 1 to May 31 of the subsequent year, the schedule PJM follows.

177. In its Answer, the Midwest ISO states that it "will consider initially adopting" a six-month period for the initial FTR allocation, followed by a re-nomination for the subsequent annual period. Midwest ISO acknowledges that such a procedure would reduce stakeholders exposure to congestion costs, compared with the proposed one-year allocation, as well as make the allocation calendar consistent with that of PJM. Accordingly, the Midwest ISO supports modification of the date for the first yearly auction of FTRs.[147]

178. Regarding the role of state commissions in alternative processes for FTR restoration and other remedial actions, several intervenors protest this function or seek clarification. IMEA and Midwest TDUs argue that municipals and transmission-dependent utilities are typically not subject to state commission jurisdiction and might be disadvantaged in proceedings that require state commissions to shift costs to retail ratepayers of the entities that they regulate. Both are concerned that the alternative process for restoration can be interpreted to enable a state commission to allocate burdens to entities over which it does not have rate jurisdiction.

179. OMS seeks clarification under the alternative process of what is subject to Commission approval and whether such approval will be sought by the Midwest ISO each time a state commission invokes this process. OMS also recommends that the available restoration measures not be limited to assignment of Counterflow FTRs but that the TEMT should instead allow discretion in how "restoration will be implemented or costs of the restoration will be allocated."[148] With respect to proposals for remedial actions by state commissions in response to requests by market participants, OMS states that the TEMT is unclear as to whether the Midwest ISO will file any state commission proposal with the Commission under section 205 of the FPA and, if so, whether the Midwest ISO will then treat and defend the proposal as its own proposal. OMS is further

[147] Midwest ISO Answer at 21.

[148] OMS at 20.

concerned that if two state commissions have contradictory positions on a remedial action for a Market Participant, the Midwest ISO will be put in a self-contradictory position. OMS is thus concerned that this provision may be unworkable as written.[149]

180. Finally, EPSA and Reliant urge the Commission to establish a deadline for the Midwest ISO to implement an annual FTR auction rather than an allocation, with an associated ARR auction. Reliant cites the advantages that this will have for the joint and common market with PJM. EPSA requests that the Commission require an annual report on progress toward such an auction.

### c) Discussion

181. Turning to the first category of protests and comments, in *PJM Interconnection, L.L.C.*, we found that the allocation process proposed for PJM's integration of Commonwealth Edison, which provided preference to network service customers, was not just and reasonable.[150] The Midwest ISO allocation proposal has largely placed network and firm point-to-point service on an equal footing. However, we agree with AMP-Ohio that entities converting existing firm point-to-point transmission service should be allowed to aggregate their total eligible megawatts and allocate those megawatts between their eligible points of delivery and receipt among the four tiers in the same fashion that entities converting existing network service are able to do. That is, a customer with two existing rights for firm point-to-point service with 100 MW each should be permitted to allocate FTRs among its rights in the proportion that it chooses up to the allowed percentage of the total megawatts in each tier. To the extent that such competition for particular paths results in pro-rationing, both network and point-to-point service would have to be pro-rationed on an equitable basis.

182. 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).[151] This reflects the reasonable expectation of long-term customers that they will retain their transmission service. We will thus reject

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[149] OMS at 20-21

[150] PJM Interconnection, L.L.C., "Order Conditionally Accepting June Annual Allocation for Commonwealth Edison Zone," Docket No. ER04-742-000 (May 28, 2004).

[151] PJM Interconnection, L.L.C., "Order Conditionally Accepting June Annual Allocation for Commonwealth Edison Zone," Docket No. ER04-742-000 (May 28, 2004), pg. 16.

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.[152] 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.

183. We agree with Cinergy and Detroit Edison that customers with annual rollover rights should not be penalized in the FTR allocation if they subsequently choose to withdraw their nominated FTRs before the final FTR awards are announced. We also agree with Great River on transitional rights and will require Midwest ISO to include in its tariff a provision guaranteeing that a customer with a transmission contract that is executed prior to the effective date of the tariff but under which service will not commence until after the start of the Energy Markets will receive the same rights as other existing customers under the current OATT.

184. Turning to the second category of protests and comments, we understand the Midwest TDUs' concern about converting system purchase contracts to FTRs. We agree that an FTR specified from a hub or zone defined to cover the potential source points of the system purchase to the sink point is the right approach to convert system purchases. However, we do not agree with the Midwest TDUs that the seller of the existing system purchase should be required to pay congestion costs from the system resources used to make the sale to the hub or zone (this could, of course, be determined through a bilateral contract). We will require the Midwest ISO to offer the "redirect" option for such zonal FTR requests that PJM has recently established and we have approved.[153]

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[152] 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, 122 S.Ct. 1012 (2002).

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

185. We agree with Detroit Edison that pumped storage units with physical transmission rights that currently cover the usage patterns that Detroit Edison describes would present a challenge to convert to financial rights and that while the peak and off-peak specification of FTR obligations greatly helps, availability of FTR options or flowgate rights could be even more beneficial. However, Detroit Edison does not provide sufficient detail on the type of rights it currently has for us to know whether it is reasonable to grant it rights beyond those available for other entities that are seeking to hedge intermittently used generation resources. Moreover, Detroit Edison's recommendation of "bidirectional" FTRs is not clear, since if specified between the same points, such FTRs would cancel themselves financially and not provide a congestion hedge.

186. Turning to the third category of protest and comments, as we noted above, under the proposed TEMT, the FTR restoration rules are the crucial link by which the Midwest ISO proposes to convert historical uses of the transmission network into sufficient financial rights to hedge congestion while allowing transmission owners that do not provide existing service that requires counterflow to support it great latitude to determine their priority in nominating eligible FTRs.

187. In section IV (B)(5), we allowed parties in NCAs (that is, load pockets) for a transition period to elect a type of congestion cost hedge that eliminated the uncertainty over the sufficiency of pro-rationed FTR allocations to fully recover congestion revenues on transmission paths with existing firm transmission service. We recognize that there are other market participants with existing firm transmission service that are not in load pockets but are concerned about congestion cost exposure. Under the proposed TEMT, these parties are eligible for restoration of FTRs to hedge power delivered from baseload resources. Here, we extend eligibility for that restoration to parties that have existing firm transmission service from resources under which they schedule power that meets the proposed TEMT's definition of base-load capacity or scheduling factor if only weekdays are considered; that is, if a generation resource or point-to-point transmission service has a 70 percent capacity factor or scheduling factor when only weekdays over the annual period are taken into account. We will also extend restoration on a seasonal basis to parties that have existing annual firm transmission service under which they schedule power that meets the proposed TEMT's definition of base-load capacity or scheduling factor for the summer peak season. That is, they will be eligible for restoration for seasonal FTRs corresponding to seasonal periods in which their capacity factors are 70 percent or higher. For seasons in which the existing transmission service does not meet this criteria, the nominated FTRs will not be eligible for restoration.

188. We agree with AMP-Ohio and the Midwest TDUs that the method proposed in the TEMT for historical determination of capacity factors to determine eligibility for restoration could disadvantage entities that have changed usage of base-load generation

resources closer to the period of the FTR allocation. We will therefore reject Section 43.2.5 and require the Midwest ISO to establish a procedure for entities to make a showing that existing base-load network or point-to-point rights qualify for restoration based on capacity or scheduling factors over the prior 12 months.

189. We agree with IMEA and the Midwest TDUs that the termination of FTR restoration, as modified here, after 3 years may be unreasonable for some market participants with longer-term existing transmission contracts. We note that within the Midwest ISO footprint, as reflected in some protests,[154] there is controversy over cost-shifting due to lags in investment in transmission, and we would not like transitional safeguards such as FTR restoration to delay needed investments over congested transmission facilities. Some parties, notably the WUMS Load-Serving Entities, have requested a transitional five-year period in which congestion charges are fully covered under certain conditions, in part to make transmission upgrades and other investments to reduce congestion. We have granted this type of full hedge for NCAs for five years. In addition to the other measures that we have established to extend eligibility for restoration of FTRs for existing transmission service, we will extend the restoration period to five years to allow for additional experience and adjustment to the LMP and FTR pricing systems.

190. Turning to the fourth category of protests and comments, we agree with Midwest TDUs and OMS that any additional temporal differentiation in the term of FTRs available through the allocation will assist in providing a more flexible hedge. Hence, especially given that the delay in Day 2 implementation should allow time for additional software development, we will require the Midwest ISO to offer nomination of monthly FTRs, peak and off-peak, in Tiers 2, 3 and 4, if possible by the first allocation and if not, then by the subsequent re-allocation.

191. We agree with OMS's recommendation that the Midwest ISO offer transmission customers the option to accept counterflow flowgate rights (FGRs) to restore pro-rationed base-load FTRs (under the modified eligibility rules that we establish above) for which restoration through assignment of counterflow FTRs based on historical usage is not available. We will require the Midwest ISO to offer this option if possible by the first allocation and if not, then by the subsequent re-allocation.[155]

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[154] *E.g.*, Cinergy Answer at 7.

[155] The entity accepting a counterflow FGR does receive additional FTRs but also takes a risk: when the constrained transmission path over which the FGR is providing congestion relief is constrained in the direction of the FGR, then the holder will owe

(continued)

192. To the extent that the Midwest ISO can implement counterflow FGRs for the purposes discussed above, then, as OMS suggests, it can also evaluate the application of such rights for purposes of providing additional FTRs across transmission capacity set aside for loop flow from outside the Midwest ISO footprint. The Midwest ISO should evaluate whether there are net benefits from creating such rights.

193. We agree with FirstEnergy and Great River that having FTR options available for the FTR auction that follows the allocation at the start of the Day 2 market is desirable, and the delay in the Day 2 market start should facilitate this taking place. However, at this time we will not delay the start of the market to this end. Heretofore, all FTR market designs have begun implementation successfully without options available, although we do recognize that different networks create different needs for FTR specification and that with the types of power flows experienced in the Midwest ISO footprint, participants would have more comfort in the hedging properties of FTR options and perhaps also flowgate rights (which are also option rights). Many of the measures that we have required heretofore will help limit the financial impact, if any, of the obligation aspect of FTR obligations.

194. We agree with OMS's recommendation (which is also proposed by Alliant, Detroit Edison, and the Ohio Commission, and supported by the Midwest ISO in its Answer) that the initial FTR allocation remain valid only for a limited period, to allow market participants time to adjust their positions based on market experience. We also agree with OMS that following that initial period, the Midwest ISO's annual FTR allocation should follow PJM's schedule, from June 1 of each year to May 31 of the following year. The schedule alignment should provide benefits for entities that transact in both markets by reducing business practice seams. However, the March 1, 2005 startup required in the Procedural Order would leave only three months for such an initial

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payments equivalent to the shadow price on the flowgate times the megawatt quantity specified in the FGR. We can assume that this will typically happen when the FTR itself takes on an "obligation" property (that is, when the price at the source node in the FTR is higher than the price at the sink nodes), meaning that the holder will pay also for the FTR at the same time. The decision to accept the counterflow FTR as a means to ensure an award of additional FTRs is thus based on the expectation that the revenues from the additional FTRs will at least offset any obligations of the counterflow FGR. In principle, if the Midwest ISO can offer this option for restoration of base-load resources, it could offer it for restoration of any pro-rationed FTR nomination. This might be attractive for entities with intermediate or peaking resources for which they feel confident that the direction of congestion on the flowgates on which they accept counterflow rights (or, more or less equivalently, the price difference from FTR source to sink) is predictable.

allocation before the start of the summer and the revised annual schedule. Hence, we will require that the Midwest ISO, with assistance from OMS and stakeholders, study the technical and implementation issues associated with an adjustment in the FTR allocation after three months of market operations and file their conclusions within 60 days of the date of this order. For example, the parties could consider limitations on what is eligible for adjustment in the re-nomination period to reduce the scope of the second allocation (for instance, awards in lower tiers could remain fixed). Alternatively, if a full re-allocation is seen as desirable, the parties could suggest other timeframes, such as retaining a six month period for the initial allocation followed by a re-allocation for the subsequent period until the following June 1.

195. We will reject Sections 43.2.6 and 43.7.3, proposing remedial state action, because they are poorly defined and may be read to improperly alter the boundaries between this Commission's, and the state commissions' jurisdiction. We agree with IMEA and the Midwest TDUs that it is unclear whether the proposal would allow a state commission to reallocate financial burdens to entities that are not subject to state commission regulation. We also agree with OMS that even if the Midwest ISO were to adopt a state commission's recommendation, and file that recommendation with the Commission as its own, the tariff does not address situations in which various state commissions may take contradictory positions. The proposals are therefore potentially unworkable as written. If the Midwest ISO chooses to revise it and propose a new version, the Commission invites and encourages state commissions to file comments on the new version. Consensus among affected states on how to address the difficult issue of cost allocation would greatly assist the Commission in fulfilling its responsibilities under the FPA.

196. Finally, in the Declaratory Order we accepted the use initially of a direct annual allocation of FTRs and declined to require the Midwest ISO to establish a schedule for implementation of an annual ARR allocation with an FTR auction.[156] We will again not require the Midwest ISO to establish such a schedule while there is substantial work to be done to implement the current proposal.

### 3. Illustrative FTR Allocation

#### a) The Midwest ISO's Proposal

197. In two past orders, we required the Midwest ISO to file an illustrative allocation of FTRs prior to the filing of its allocation methodology.[157] The Midwest ISO complied

[156] *See* Declaratory Order at P 74.

[157] *See* Midwest Independent Transmission System Operator, Inc., 102 FERC ¶ 61,338 (2003) (clarifying Declaratory Order).

with this requirement with an informational filing.[158] The Midwest ISO notes that the illustrative results are not indicative of the likely outcome of the actual allocation process for several reasons: the network model used for the illustrative allocation was for an earlier period than the one that will be used for the actual allocation and did not differentiate between peak and off-peak; the software for conducting the restoration step following tiers I and II was not yet available, so this step was manually estimated by assigning participants some level of their historical FTRs in those tiers while only using nominated FTRs for the subsequent tiers; several other assumptions were made about how market participants would nominate in each tier, which may not reflect what they actually do; and all holders of GFAs were assumed to have elected Option B for treatment of GFAs in the Energy Markets. Midwest ISO argues that the experience with the illustrative allocation and its results improve understanding of the process rather than provide a reflection of likely actual results.

### b) Protests and Comments

198. OMS recommends that the Midwest ISO not conduct another illustrative FTR allocation, but rather focus on correcting the FTR modeling and meeting associated milestones – such as for LMP validation and performance of the State Estimator – and then undertake a re-allocation after six months of market operations. OMS recommends that the Midwest ISO meet all published milestones relevant to FTRs, including but not limited to the functioning of the state estimator system and LMP validation.

199. Dynegy argues that given its assumptions, the illustrative allocation did not serve its intended function of providing insight into the FTR allocation. Otter Tail states that given the many unresolved issues surrounding the illustrative allocation, the Commission should not give the results any weight in decisionmaking.[159]

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

[159] Otter Tail at 22.

200. Ameren and Xcel request that the Commission require the Midwest ISO to undertake the illustrative allocation again based on updated data and software and taking seams into account more accurately.[160] Xcel requests that this revised illustrative allocation take place before implementation of the actual allocation process.[161]

### c) Discussion

201. We recognize and agree with many of the concerns about the illustrative FTR allocation results. In retrospect, it appears that the ongoing evolution of the network model used for the FTRs, the large quantity of data for the Midwest ISO to process in a short time with the staff it deployed, a poorly defined procedure, at least at some points, for stakeholder input, and the many changes in the allocation methodology during the months in which the Midwest ISO was carrying out the illustrative allocation resulted in an outcome that frustrated many stakeholders rather than lead to increased confidence in the FTR methodology.

202. Our Procedural Order has already stated our interest in not repeating the illustrative FTR Allocation, but rather moving towards a process to establish a final initial allocation that addresses stakeholder concerns about the FTR modeling and allows sufficient time to correct errors and include adjustments to the allocation (e.g., by state commissions) before the start of the Day 2 market. The Procedural Order requires that the initial allocation is filed 90 days prior to the start of the market.[162] Even with the delay in the start of the market, this effort will be an ambitious undertaking and we will not add steps that would cause further delay.

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

### a) The Midwest ISO's Proposal

203. This section addresses protests and comments seeking to modify the Midwest ISO's proposed rules for FTR awards associated with designation of new network resources, retirements of network resources and transmission upgrades and expansion. Newly designated network resources that meet a deliverability requirement are eligible

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[160] Ameren at 13; Xcel at 13-15.

[161] Xcel at 13-17.

[162] *See* Procedural Order at P 95.

for FTR nomination in subsequent allocation periods. If they replace a base-load resource that is eligible for FTR restoration, then the new resource will be eligible for such restoration. Network resources that are retired have their FTRs terminated at the discretion of the FTR holder and the Midwest ISO.[163]

204. Market participants that fund Network Upgrades and decline credits may receive FTRs equal to the capability created by the Network Upgrades, choosing any Receipt to Delivery Points consistent with the upgrade. The initial allocation shall be for one year maximum, with subsequent allocations depending upon the amount that the Network Upgrade increases transfer capability.

### b) Protests and Comments

205. FirstEnergy protests that the TEMT should leave the decision to terminate FTRs associated with generation resources retired during an allocation period to the load-serving entity, rather than to both the load-serving entity and the Midwest ISO. FirstEnergy argues that the load-serving entity will still need to hedge on behalf of load and thus should make the decision whether to keep the FTR. Southwestern argues that the TEMT should allow for immediate cancellation of FTRs associated with retired generation.

206. Lincoln Electric and the Midwest TDUs argue that the TEMT should include provision for long-term FTRs; that is, FTRs that are allocated for more than one year and possibly for the life of an existing or new asset. They argue that without this provision of long-term delivered price stability, investment in low cost baseload generation will be adversely affected, because of the possibility that pro-rationing in annual FTR allocations will expose investors to high congestion charges. This could encourage investment in higher cost units located closer to load instead.

207. The Midwest TDUs claim that there are a number of other reasons why under the proposed rules, FTR awards for new resources will not be effective. They argue that participant funding rules in the TEMT do not guarantee that FTRs awarded for transmission investments will be available each subsequent year in the initially-awarded amounts (*e.g.*, due to changes in system topology) nor available sufficiently to hedge congestion charges from source to sink. Moreover, purchases in the annual or monthly auctions are not likely to be sufficiently financially stable to support new investments. The Midwest TDUs further argue that the proposed rules for obtaining new short-term point-to-point FTRs will allow speculators to crowd out requests for new short-term network FTRs and that this will adversely affect investment decisions.

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[163] Module C, Section 43.6.4, Original Sheet No. 644.

#### c) Discussion

208. We agree with FirstEnergy and Southwestern that the Midwest ISO should clarify the rules for FTRs from network resources that are retired. If a network resource is retired, then this could change the feasible set of FTRs. Maintaining the outstanding FTR associated with the retired resource could then create a revenue inadequacy. The Midwest ISO and stakeholders should determine whether to allow the FTR to remain as-is through the allocation period, whether to adjust it for purposes of simultaneous feasibility, or whether to terminate it.

209. We agree with Lincoln Electric and the Midwest TDUs that long-term FTRs could be attractive as support for investment in long-term transmission assets, although they come with risks that the intervenors do not examine (*e.g.*, that a long-term FTR obligation, subsequent to changes in network topology, could become a financial obligation for a long period). However, we will not require such FTRs to be made available upon market start, as this would likely delay the start. We will direct 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 agree with the Midwest TDUs that there is no guarantee that sufficient FTRs to support fully hedged planned generation investment can be purchased in the monthly or annual FTR auctions. However, this is the case in all the markets that implement FTRs.

### 5. FTRs in Retail Choice States

#### a) The Midwest ISO's Proposal

210. Under the TEMT, FTR allocations in states with retail choice will be revised daily and annually to reflect load switching.[164] In the annual allocation, a Market Participant's load forecast to support its maximum nomination eligibility will reflect load switching between the annual FTR allocations. During the FTR allocation period, revenues from already allocated FTRs will be re-allocated using ARRs. An ARR entitles the holder to revenue based on clearing prices in the monthly FTR auction. An ARR funding obligation is the obligation that an FTR holder has to pay ARR holders. Each month, Midwest ISO will allocate ARRs and ARR funding obligations based on Load reported to have shifted between market participants under state retail choice programs during the month.

[164] Module C, Section 43.7.2, Original Sheet Nos. 646-47.

### b) Protests and Comments

211. A number of intervenors appeared to be unclear about the rules for allocation of ARRs and ARR funding obligations to account for load shifting during the month – that is, in between the monthly auction. Several intervenors interpreted the TEMT as only allowing ARRs to account for changes from month to month, rather than account for load shifts on the day that they occur. In its Answer, the Midwest ISO states that it appreciates the concerns about FTR value following load in retail access states and that it is currently working with the states and other interested stakeholders to develop appropriate business practices to enhance portability of FTRs.[165] The Midwest ISO further states that the TEMT already allows for daily load shifts in the monthly ARR settlements.

212. AMP-Ohio requests that the Commission clarify that it will receive FTRs and not ARRs despite being in a retail choice state.

### c) Discussion

213. We find that while the Midwest ISO's Answer is clear that ARRs will follow load shifts on a daily basis, the TEMT is indeed not clear in this regard. Hence, we request that the Midwest ISO revise its tariff accordingly to clarify this rule. We find it clear in the TEMT that entities in retail choice states will only receive ARRs or ARR funding obligations to the extent that they have gained or lost load through retail competition and not otherwise. Hence, we will not require the tariff to be clarified per AMP-Ohio's request.

## 6. Locational Marginal Pricing

### a) The Midwest ISO's Proposal

214. The Midwest ISO proposes to use locational marginal pricing (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. Midwest ISO further notes that LMP provides a long-term price signal that can be used to assist investment decisions in generation and transmission.

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[165] Midwest ISO Answer at 20.

### b) Protests and Comments

215. Basin, *et al.*, comment that the computational methods for calculating LMPs do not allow market participants to replicate the results through similar models, thus increasing risk and making it difficult or impossible to substantiate or audit the calculations as a means to uncover and correct errors.[166]

216. Manitoba Hydro argues that the proposed TEMT treatment of external transactions could result in double charging for losses (and congestion).[167] MidAmerican notes that it owns a generating unit at the border of Midwest ISO region and has "physical ownership of outlet transmission from that generation to the MidAmerican system" which does not rely on transmission in the Midwest ISO footprint.[168] MidAmerican states that it is important that power delivered from that unit is not subject to Midwest ISO congestion and loss charges.

217. Midwest Municipal Transmission Group states that its members, who are transmission dependent utilities, will face LMPs on an unblended nodal basis because, unlike larger vertically integrated utilities, their service territories are typically too small to significantly dilute nodal prices to load through zonal averaging. They claim that this outcome will threaten the economic viability of small systems, which are too small to undertake much transmission expansion or locate new generation close to load.

218. Midwest Municipal Transmission Group argues that a transmission dependent utility located at one or two nodes in a transmission owner's system could have its LMPs aggregated with the LMPs of the transmission owner as a means to avoid high congestion costs caused by the transmission owners decision not to expand the system to relieve the congestion.[169] They argue that if the transmission owner can refuse this pricing method, it will have an advantage in attempting to take over the transmission dependent utility by offering the latter's customers the lower, averaged zonal price. Further, they note that if an ITC is formed, area transmission dependent utilities should have the option of aggregating within the ITC pricing zones. Moreover, the ITC should have the ability to determine the scope of the load averaging zone.

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[166] Basin, *et al.*, at 26.

[167] Manitoba Hydro at 10-11.

[168] MidAmerican at 5.

[169] Midwest Municipal Transmission Group at 10-14.

219. Minnesota Entities claim that the introduction of LMP should not be seen as an inducement for new transmission construction.[170] They argue that much of the transmission in their region was developed with multiple partners and joint ownership and that the current tariffs and relationship with the Midwest ISO has reduced that cooperation and created uncertainty about cost recovery. They state that LMP is designed for allocating scarce capacity but will not provide an incentive for transmission expansion.

220. Similarly, Midwest SATCs state that while they are not opposed to the use of LMP and FTRs for purposes of short-term congestion management, they are concerned that the Midwest ISO and the Commission not overestimate the utility of LMPs for transmission expansion.[171] To that end, they urge the Commission to remain "committed to a well-rounded approach to transmission development." They note that a Regional Expansion Criteria and Benefits Task Force has recently been formed by Midwest ISO stakeholders to develop criteria for evaluating and allocating costs related to projected that are to be included in the Midwest ISO's Transmission Expansion Plan.

### c) Discussion

221. The LMP calculation under the Midwest ISO market rules will reflect a very large number of generation and transmission constraints. There is also much confidential bid data on physical characteristics as well as offer prices that enters the optimization. Hence, without all these factors taken into account, "replication" of the LMP result, as proposed by Basin, *et al.*, can be an approximation at best for entities that do not have access to the confidential data. For that reason, market participants must rely on the independence of the Independent System Operator or Regional Transmission Operator to provide safeguards against invalid price outcomes. In this Order, we have provided additional safeguards in this regard for any *ex post* price corrections needed to correct pricing errors.

222. With respect to Manitoba Hydro's comment, we will require the Midwest ISO to clarify that external transactions will not be double-charged for congestion and losses. With respect to MidAmerican, we will require the Midwest ISO to clarify that power delivered from a non-jurisdictional Midwest ISO generation unit with existing firm transmission service at the Midwest ISO boundary is not subject to congestion or loss charges. However, if such a unit schedules power into the Midwest ISO footprint, or

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[170] Minnesota Entities at 8-9.

[171] Midwest SATCs at 12-14.

offers it into the Midwest ISO Energy Markets, it will be scheduled and dispatched in accord with LMPs.

223. We have approved elsewhere zonal pricing for load that includes multiple load-serving entities within the zone (*e.g.*, delineating certain states as zones in ISO-NE). However, these zonal definitions were determined as part of stakeholder processes and not as a result of Commission direction. We will not here require load-serving entities in the Midwest ISO footprint to merge into pricing zones, but encourage stakeholders to consider such aggregations in future discussions, including those pertaining to formation of ITCs.

224. We agree with Minnesota Entities and Midwest SATCs that while LMPs and FTRs are the appropriate market design for short-term congestion management, they need not be the only policy in the tariff for transmission investment. We encourage the development of the RECBTF transmission planning process.

## *E. Marginal Losses*

### 1. The Midwest ISO's Proposal

225. As noted in section IV (B), the Midwest ISO has complied with the Declaratory Order in proposing to implement locational marginal loss pricing and a method of refunding the resulting surplus loss revenues with a method that is equitable and efficient.

226. Under the proposed TEMT, the total loss surplus is defined as the sum across all control areas of the day-ahead and real-time loss surplus minus the determined value of inadvertent energy.[172] As described by Dr. McNamara, the Midwest ISO and stakeholders adopted a refund method that allocated the surplus on a regional basis and sought to minimize subsidization across regions.[173] The loss surplus is thus refunded back to loss pools, which are defined as a single control area or an aggregation of control areas. Each such pool has a share of the total surplus, calculated by the Midwest ISO on a *pro rata* basis per the cost of supplying losses to Load scheduled by market participants (and excluding Load served under GFAs). That is, the share reflects the actual losses incurred on an hourly basis. Within each pool, the share is allocated to market participants on a pro-rata basis per the participant's Load Ratio Share (again excluding Load served under GFAs).

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[172] Module C, Section 40.6, Original Sheet No. 597.

[173] McNamara testimony at 53-54.

227. The TEMT as filed does not include detail on how the Midwest ISO will determine the composition of loss pools. Dr. McNamara testifies further that the Midwest ISO will seek to identify aggregations of control areas in which similar actual losses have been identified and that the aggregation must be large enough to include multiple load-serving entities, but small enough to capture sufficient differences in losses between areas. Moreover, he states that the pools can be modified as transmission losses change.[174]

### 2. Protests and Comments

#### a) Allocation of Surplus Loss Revenue

228. AMP-Ohio states that the Midwest ISO should identify the loss pools in an attachment to its tariff.

229. Crescent Moon states that as a condition for the TEMT being effective, the Midwest ISO should present its marginal loss surplus methodology in detail.[175] Crescent Moon states that possible rebates methods include returning the extra payments to customers that overpaid losses, allocating the extra revenue to customers that are likely to under-recover congestion revenues due to their FTR allocation, or applying the revenue towards construction costs for new transmission network facilities.

230. Great Lakes and Southwestern argue that the consequence of the Midwest ISO's proposed refund of excess loss payments on a regional basis will be to disadvantage load-serving entities that rely upon remote generation resources. Great Lakes argues that the Commission should ensure that the Midwest ISO returns surplus payments to those that are burdened with the change in loss calculation methodology and that the current proposed TEMT rule is unduly discriminatory and should be rejected. Southwestern states that the surplus should be returned to the load that overpaid.

231. Otter Tail requests that, if the Commission approves marginal loss pricing for the Midwest ISO markets, it should direct the Midwest ISO to clarify the design of the loss pools and define such pools such that only regions with similar loss characteristics are included in the same pool.[176] Otter Tail expresses concern that if regions with different

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[174] McNamara testimony at 53-54.

[175] *See* Crescent Moon at 49-50.

[176] Otter Tail at 20-21.

characteristics were included in the same pool, and loss surplus revenue was refunded on a load ratio share, then cost shifts would take place.

232. The Midwest TDUs claim that the Midwest ISO proposal for loss pools will not prevent a net increase in loss-related charges, "for those who, like TDUs, import more power (or do so at times of higher load-side LMPs) than is average for their host control area(s)." Hence, the Midwest TDUs argue that load-serving entities with long-term contracts or acquisitions that were made based on the assumption of average loss pricing would face significant cost shifts under marginal loss pricing.[177]

### b) Financial Loss Rights

233. The Midwest TDUs propose a financial loss hedging right that would pay the difference between marginal and average losses for a schedule from the resource point to the delivery point associated with the financial right, whether or not the transaction is actually scheduled. The Midwest TDUs argue that such a right would hold harmless load-serving entities with long-term resource commitments, while not affecting dispatch decisions based on marginal losses. Further, such rights would be limited to existing network resources or their equivalent, and could be further restricted to base-load and intermediate resources. Only existing resources would be eligible.

### c) Other Issues

234. IMEA requests further information on how marginal losses are calculated, in particular asking how the loss calculation is made mathematically. They argue that since the marginal loss calculation will generate surpluses that are refunded, "customers should therefore have the information necessary to determine how the losses and resulting surpluses are computed."[178]

235. The Midwest ISO TOs argue that the TEMT is deficient on loss calculations.[179] They argue that there are no tables or matrices showing the losses for which each transmission customer will be responsible. They argue further that there is no detailed formula that would allow a customer to determine ahead of a transaction what its responsibility for losses will be. Hence, they claim that this violates the Commission's statements that customers should have "beforehand pricing" certainty and also statutory requirements of notice of rates and charges.

[177] Midwest TDUs at 85-88.

[178] IMEA at 11.

[179] Midwest ISO TOs at 34-37.

236. The Midwest ISO TOs claim that the loss proposal in the TEMT violates the Midwest ISO Agreement and, in particular, the Midwest ISO's "fiduciary responsibility to maximize transmission revenues."[180] They argue that this pricing method does away with existing transmission service charges associated with losses but does not propose an "alternative revenue producing method through a proposed tariff provision."

237. The Midwest ISO TOs claim that the Commission cannot legally allow the loss pricing method because it results in customers paying excessive charges, even though the refund mechanism reduces the harm.[181] They argue that if the rate is excessive, then it is not just and reasonable under the FPA. They argue further that the Commission "many years adopted the policy of precluding the use of marginal losses if transmission rates were based on embedded costs" and that at least one Court affirmed this policy. The Midwest ISO's filing contains no explanation of why this precedent no longer applies.

### 3. Discussion

238. We will approve the Midwest ISO's implementation of LMP with a marginal loss component with clarification and modification and subject to the safeguard measure discussed in section IV (B). The marginal loss pricing rules will be applicable to all entities requesting new transmission service from the Midwest ISO one year after the start of the Day 2 markets and to all market participants following the termination of the transition period delineated in section IV (B). We will also require the Midwest ISO to consider additional measures to provide loss hedging instruments at the termination of the transition period, if not sooner (for new transmission customers).

239. As we requested in the Declaratory Order, Midwest ISO and stakeholders have developed a method for refunding marginal loss surplus that does not refund losses on a transactional basis and thus mute the loss price signal. However, we find that while the testimony of the Midwest ISO's witness suggests a careful analysis that will underlie the determination of the loss pools, including some flexibility to modify the aggregation over time, the detail presented in the TEMT filing is not sufficient to allay the concerns of some market participants that they will find themselves significantly exposed to marginal loss charges—that is, without an opportunity to receive a greater than average share of the surplus that might prove sufficient to hedge such exposure. We will thus require Midwest ISO to address the concerns of these stakeholders and any others that are concerned through either specific remedies for particular regions or through further modifications of the loss pool method. As required in section IV (B), the Midwest ISO

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[180] Midwest ISO TOs at 34-37.

[181] Midwest ISO TOs at 34-37.

and stakeholders will continue discussions on the methodology for the refund of surplus loss revenues and the Midwest ISO will file the revised tariff sheets no later than 270 days following the start of the Day 2 markets.

240. The Midwest TDUs request that the Midwest ISO develop a financial loss right that can serve as a mechanism for refunding back the difference between marginal and average losses to holders of the right. Loss rights have been discussed recently in several ISO markets, although an appropriate design has not yet been approved by the Commission. We will require the Midwest ISO and stakeholders to develop proposals for financial loss rights that could be implemented following the termination of the transition period.

241. We disagree with the Midwest ISO TOs' claim that marginal losses are excessive, and therefore unjust and unreasonable. The design of the proposed marginal losses calculation is to refund back any excess losses via a refund mechanism. Marginal losses reflect the true value of additional delivered energy in the same way that marginal congestion charges do. Given that marginal losses (and congestion) can only be determined after the fact, based on system flows, there is no way to estimate and reflect marginal losses (and congestion) *ex ante*. We do not consider this process of determining losses to be unjust and unreasonable. Hence, we have approved marginal losses for the New York ISO and ISO New England markets. We note that the Midwest ISO TOs contention that marginal losses are prohibited by Commission and that court-approved decisions[182] rely on precedent prior to the development of the Commission's congestion management policy, that includes LMP pricing. Marginal losses are typically part of LMP pricing, along with congestion charges, in providing the market with least-cost dispatch information that incorporates the impact of distance on energy costs. Since LMP pricing will replace physical scheduling in the energy market to manage congestion in the proposed energy market, it is more efficient to calculate losses on a marginal basis.[183]

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[182] *See* Northern States Power Co., 59 FERC ¶ 61,100, 61,369, *reh'g denied*, 60 FERC ¶ 61,076, (1992), *clarification denied*, 64 FERC ¶ 61,111 (1993), *aff'd*, Northern States Power Co. v. FERC, 30 F.3d 177 (D.C. Cir. 1994).

[183] We do not address the Midwest ISO TOs' claim that the marginal losses proposal eliminates existing policy consistent with Order No. 888 that provides transmission service charges for losses. Order No. 888 only requires that transmission customers must make provision for real power losses. *See* Order No. 888 at 31,709.

## *F. Market Monitoring and Market Power Mitigation*

### 1. Overall Market Monitoring and Mitigation Plan

#### a) The Midwest ISO's Proposal

242. The Midwest ISO's monitoring and mitigation plan is laid out in Module D of the proposed TEMT. Dr. David Patton of Potomac Economics, the IMM, prepared the market monitoring and mitigation plan in conjunction with the Midwest ISO and its stakeholders. He also filed testimony that includes a Market Analysis discussing the specifics of Narrow Constrained Areas (NCAs) and Broad Constrained Areas (BCAs), as defined below. The monitoring and mitigation plan for the Midwest ISO was originally filed as Attachment S to the Midwest ISO OATT, and conditionally accepted by the Commission on December 20, 2001.[184] The mitigation proposal builds upon a number of meetings and discussions Dr. Patton has had with the stakeholders at the Midwest ISO, and on a Commission sponsored technical conference held on June 26, 2003. It incorporates guidance given by the Commission in various orders.[185]

243. The Midwest ISO's market monitoring plan is to be implemented by an IMM that reports to the Midwest ISO's board of directors and coordinates with the Midwest ISO's Market Monitoring Liaison Officer. The TEMT states that the IMM has complete independence to perform the activities necessary for impartial and effective market monitoring within the scope of the Plan. No person, party or agent, including the Midwest ISO and state regulatory agencies, shall have authority to screen, alter, delete, or delay IMM investigations or the preparation of findings, conclusions, and recommendations developed by the IMM that fall within the market monitoring responsibilities in the market monitoring plan. The IMM will report its findings to the Commission, state regulatory commissions and the Midwest ISO.

244. The monitoring plan establishes that the IMM will monitor the markets and services provided by the Midwest ISO, including the imbalance energy market, any ancillary services market, any market for the purchase or sale of transmission rights, and any other market administered, coordinated or facilitated by the Midwest ISO.

245. The mitigation plan imposes mitigation in the energy markets upon entities in

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[184] *See* Midwest Independent Transmission System Operator, Inc., 99 FERC ¶ 61,237 (2002); Midwest Independent Transmission System Operator, Inc., 101 FERC ¶ 61,228 (2002).

[185] *See, e.g.*, Market Rules Rehearing Order, March 13 Order.

constrained areas (areas in which a constraint is actively binding) that fail conduct and impact tests such that their conduct is significantly inconsistent with competitive outcomes (as indicated by conduct threshold levels) and would result in a substantial change in one or more prices in the energy market or in a Offer Revenue Sufficiency Guarantee Payment (uplift charges to cover start-up and no-load costs) in the energy market (by exceeding impact thresholds). The conduct and impact framework proposed in Module D is very similar to the mitigation procedures approved for the NYISO and ISO-NE. They too set conduct and impact thresholds and use default offers and sanctions to rectify behavior that fails the conduct and impact tests. Categories of potentially problematic behavior include physical withholding (of generation or transmission), economic withholding, uneconomic production, and uneconomic market participant bids or virtual transactions.

246. Electrical areas that may be subject to mitigation are classified as NCAs or BCAs. NCAs are areas that are potentially more subject to the exercise of market power abuse and are subject to more stringent thresholds for mitigation. BCAs will not be identified in advance by the IMM, but will be defined dynamically when constraints arise on flowgates. The IMM proposes using a Generation Shift Factor (GSF) threshold test to determine which generators should be included in the BCA, and thus be subject to mitigation.

247. When a Generation Resource fails the conduct and impact tests in either an NCA or a BCA, in the case of economic withholding a default offer (the unit's reference offer) replaces its offer, after the bidder is given the opportunity to justify the offer as consistent with competitive behavior and cannot do so. The default offer is applied prospectively with a delay of no more than two to three market intervals in the Real-Time Market, *i.e.*, 10 to 15 minutes. In the Day-Ahead Market, mitigation will be applied the following day, assuming market conditions are unchanged. The default offer will set the price in the market only if it is the marginal offer selected. When default offers cannot be used, as in the case of physical withholding or uneconomic production, sanctions (which may include penalties) are assessed. In the case of virtual trading, when a supplier fails the conduct and impact tests, prospective quantity limits on its virtual trades at one or more locations may be imposed.

248. The IMM will also monitor the markets and services administered by the Midwest ISO for any conduct that may distort competitive outcomes, but that does not trigger the thresholds specified for the imposition of mitigation measures. If the IMM finds such conduct, the Midwest ISO will make a filing with the Commission under section 205 of the FPA, requesting authorization to apply appropriate mitigation measures. The IMM will also monitor the actions of the Midwest ISO to identify any actions that substantially distort competitive outcomes in any markets administered by the Midwest ISO. The IMM will then recommend changes in market rules and procedures as needed.

### b) Protests and Comments

249. OMS believes that all the Midwest ISO's markets and services should be monitored, including capacity markets or mandatory capacity constructs, procedures for ancillary services provision, and any person or entity that participates in any of these markets or that takes service under or is a party to any tariff or agreement to any tariff or agreement administered by the Midwest ISO. Midwest TDUs want mitigation applied to bilateral and long-term markets, or at a minimum monitoring to extend to these markets. Wisconsin Retail also advocates monitoring for bilateral and long term markets. Steel Producers want every abuse of market power to be identified and mitigated, even without a showing of substantial market power.

250. Others argue for narrower monitoring and mitigation, from what participants or areas are monitored to what the IMM monitors for. The Midwest ISO TOs say that the monitoring and mitigation plan should not be applied to control areas, as could be construed from Section 50.3. Likewise, AMP-Ohio says the language in that Section should be modified to clarify that the IMM has the authority to monitor and investigate only transactions involving the Midwest ISO system.

251. FirstEnergy says the IMM has too much discretion, and that there should be more specificity in descriptions of violations and penalties. For example, Section 63.2.a provides that behavior subject to mitigation would include activity "significantly inconsistent with competitive conduct" and which results in a "substantial change" in prices in an energy market, without defining these terms. In addition, FirstEnergy says that Section 63.2.b of the TEMT allows for categories of conduct "not listed" in the TEMT to be considered "significantly inconsistent" with competitive conduct,[186] and that the "general guidance" in the provision is too vague for comfort.

252. WEPCO says that the TEMT should establish a process for appeal of determinations under Section 63.3.b in which temporary mitigation measures may be imposed.

253. In its Answer, the Midwest ISO says that the market monitoring and mitigation proposal included as Module D of the TEMT has been the subject of extensive stakeholder discussion and extensive Commission proceedings. The Midwest ISO believes that the proposal incorporates all of the guidance and directives provided by the Commission in these prior proceedings.

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[186] Section 63.2.b provides that categories of conduct that are inconsistent with competitive conduct include, but are not limited to, those listed in Section 63.3.

#### c) Discussion

254. We believe that the TEMT generally establishes the appropriate degree of independence for the IMM, such that it can effectively monitor the Midwest ISO markets. As noted in our Order on Rehearing regarding Market Behavioral Rules, we are presently undertaking a comprehensive review of the role of market monitoring units in RTOs and ISOs.[187] While we are requiring certain changes to the Midwest ISO's proposals with respect to the IMM's overall function and role, in the event our broader policy determinations require further changes to the function and discretion of the IMM as well as market monitoring units in other ISOs and RTOs, we will undertake such changes prospectively.

255. The IMM will periodically assess the effect of bilateral energy or capacity markets and private transmission rights that the Midwest ISO does not administer, coordinate, or facilitate. The Interim Generation Market Power Analysis and Mitigation Policy process adopted by the Commission on April 14, 2004 will provide another measure of security.[188] In it the Commission requires all applicants for market based rate authority including for bilateral sales into an ISO or RTO market with Commission-approved market monitoring and mitigation to pass the market power test. An applicant would pass the market power test if it passed both a pivotal supplier test and a market share test. We find that the combination of the IMM's oversight and the market power testing associated with the Interim Policy is sufficient to prevent or catch any problems in the bilateral and long-term contract markets.

256. In response to the Midwest ISO TOs' concerns about the application of the monitoring and mitigation plan to control areas, we believe that it is appropriate for the IMM to monitor for anti-competitive problems at the control area level such as unnecessary withholding of capacity from the Energy Markets on so-called reliability grounds. Affiliate favoritism should be monitored for as well. Because the control area operators' responsibilities vary across the Midwest ISO, it would be difficult to detail all the ways that a transmission owner that is also a control area operator could manipulate the market. For this reason, we believe it is appropriate that the IMM develop a plan to monitor for anticompetitive behavior at the control area level, to implement that plan, and to notify the Commission should it find any such behavior.

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[187] Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 107 FERC ¶ 61,175 at P 168 (2004).

[188] *See* AEP Power Marketing, Inc., *et al.*, 107 FERC ¶ 61,018 (2004).

257. We find that the conduct and impact approach with its associated thresholds is an appropriate approach to mitigation in the Midwest ISO's market. The conduct and impact approach allows for a lighter handed approach to mitigation, in which the market is allowed to function as is, except when problems are detected. The TEMT establishes that the IMM will monitor all the markets which the Midwest ISO runs, including energy markets and any later capacity markets.

258. We support the use of tighter thresholds in areas that are more likely subject to the exercise of market power. This is because when the exercise of market power is more probable, the costs of interfering with the market are more likely to be overshadowed by the benefits of preventing the exercise of market power.

259. In response to FirstEnergy's concerns about the language in Section 63.2.a, we are also concerned about the discretion of a market monitor in mitigating and in administering penalty charges to market participants or applying other sanctions for their behavior. If these were the only provisions on how the IMM will be mitigating the market, we would be very concerned. However, the TEMT provides in Section 62.b, in part, "…the Mitigation Measures authorize the mitigation of specific conduct only when the conduct exceeds well defined conduct thresholds and when the effect on market outcomes of the conduct exceeds well-defined market impact thresholds. The conduct thresholds established in Section 64.1 lay out in detail the thresholds for behavior for economic withholding, physical withholding and uneconomic production that are considered to be problematic, i.e. "significantly inconsistent with competitive conduct".[189] Likewise, the impact thresholds in Section 64.2 give guidelines for price effects, i.e. substantial changes in prices that will trigger mitigation if there is a binding constraint and the conduct test is also failed by the market participant. The conduct and impact thresholds provide criteria for mitigation for physical and economic withholding and for uneconomic production. For example, in BCAs, the conduct threshold for physical withholding operating is defined as a real-time output level that is less than 90% of dispatch directions or withholding more than the lower of 5 percent or 200 megawatts. We find that the Midwest ISO must amend Section 63.2.a to refer to Sections 64.1 and 64.2 to define the phrases "significantly inconsistent with competitive conduct" and "substantial change", respectively.

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[189] Section 64.1.1 gives the specific thresholds for identifying physical withholding, Section 64.1.2 gives those for economic withholding, and Section 64.2.3 gives them for uneconomic production.

260. With respect to FirstEnergy's concerns that Section 63.2.b of the TEMT allows for categories of conduct not listed in Section 63.3 to fall, in an after-the-fact review, in the category of "inconsistent with competitive conduct" and thus be inappropriately subject to mitigation by the IMM, we agree. We find that only identified categories of conduct should be subject to mitigation by the IMM. Thus, in Section 63.2.b, we will direct that the phrase ", but are not limited to," should be removed.[190] We add, however, that the Market Behavior Rules we adopted late last year provide the Commission a vehicle to address market behaviors and remedy market abuses that may not be identified in the TEMT.[191]

261. The IMM and the Midwest ISO must have, and do have, the obligation to identify problems in the market. Thus, Section 52.3 of the TEMT establishes, among other things, that the IMM may recommend to the Midwest ISO modifications to market rules or tariffs, and may bring matters – including "significant market problem[s]" - to the attention of the Midwest ISO and/or various government agencies (including the Commission). Likewise, Section 62.c of the TEMT provides that, in the event that the IMM identifies "conduct that may distort competitive market outcomes," the Midwest ISO shall file with the Commission to apply "appropriate Mitigation Measures."[192] As the Midwest ISO and the IMM gain experience during the first years of operation of the Energy Markets, we would expect them to use this authority to further refine the tariff accordingly by identifying further and more precise conduct and criteria that may be inappropriate and that may have an unacceptable impact upon the markets, and what mitigation may be appropriate in such circumstances.

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[190] Similarly, we direct that the phrase ", but is not limited to," be removed from Section 63.3.a.

[191] *See* Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 105 FERC ¶ 61,218, *clarified*, 105 FERC ¶ 61,277 (2003), *order on reh'g*, 107 FERC ¶ 61,175 (2004).

[192] While Section 63.3.d of the TEMT provides that the IMM may "seek to amend" the list of "categories of conduct" in Section 63.3.a that "may warrant mitigation" to include other conduct that "would substantially distort or impair the competitiveness" of the Energy Markets, and may "seek [from the Commission] such other authorization to mitigate the effects of such conduct," we find that proposed revisions to the Midwest ISO's TEMT (including the list in Section 63.3.a) should be filed by the Midwest ISO. The IMM's ability to mitigate, in turn, would be governed by whatever language was the then-operative language of the TEMT. In this regard, see our discussion on temporary mitigation measures below.

262. With respect to so-called "temporary Mitigation Measure[s]," Section 63.3.b of the TEMT provides that such mitigation measures may be imposed "pending the revision" of a rule, standard, procedure or design feature. We find the imposition of such measures unacceptable, and will direct that this provision be removed from the TEMT. Market Participants should not be subject to mitigation by the IMM under the TEMT when the conduct that would lead to mitigation has not yet been incorporated in the list in Section 63.3.a of the "categories of conduct" that "may warrant mitigation." However, we note our intent to provide in the near future a mechanism for fast-track processing of tariff changes that are needed to resolve market problems.

263. We note that, in a number of places,[193] Module D of the TEMT uses the phrase "causes or contributes to" or sometimes just "contributes to" to identify conduct that is, essentially, proscribed. We find that, in the context of Module D, proscribed conduct should be conduct that "causes," and that the phrase "contributes to" merely adds duplicative and unnecessary language and may create confusion and uncertainty in the future. Accordingly, in Module D of the TEMT, the phrase "contributes to" should be removed wherever it appears, and in its place the phrase "causes" should consistently be used throughout.[194]

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[193] Examples include Sections 63.3.a.i, iii and iv – which addresses operating a transmission facility in a manner that "causes or contributes to" a Binding Transmission Constraint, increasing output to levels that would otherwise be uneconomic in order to "cause or contribute to" a Binding Transmission Constraint, and submitting an offer in the Day-Ahead Energy Market that is not economically justified and that "causes or contributes to" substantial divergence between prices in the Day-Ahead and Real-Time Energy Markets. Other examples that use the phrase "contributes to" rather than just "cause" include Sections 64.1.1.d; 64.1.3.a.i and ii; 64.2.1.a; and 65.5.2.c.

[194] In addition to the changes to Module D of the TEMT directed elsewhere in this order, we direct the Midwest ISO to make the following changes to better clarify the meaning of particular provisions:

1. Sheet No. 708, b.i.: strike "penalties, sanctions, or fines" and insert "penalty charges".
2. Sheet No. 712, b.: strike "penalties, sanctions, or fines" and insert "penalty charges".
3. Sheet No. 715, f.: strike "sanctions" and insert "penalty charges".
4. Sheet No. 790: strike "financial penalties" and insert "penalty charges".
5. Sheet No. 791: strike "financial penalty" and "financial penalties" and insert "penalty charge" and "penalty charges", respectively.

(continued)

### 2. BCAs

#### a) The Midwest ISO's Proposal

264. A 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. Market power concerns are thus minimal in these areas. BCAs are not identified in advance. The mitigation process for BCAs begins when a transmission constraint becomes active.

265. When a constraint becomes active, the IMM will identify the generators that are effective in managing the constraint, and define them to be in the BCA. To determine which generation units are in the BCA and thus subjected to the conduct and impact tests associated with the BCA, the resource's generation shift factor (GSF) for that flowgate is compared to a pre-established Constraint Generation Shift Factor Cutoff (GSF Cutoff) for that same flowgate. 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. The GSF may be either positive or negative. A positive GSF means that additional production from that unit will cause additional flows over the flowgate in question.[195] A negative GSF means that additional production from the unit

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6. Sheet No. 792: strike "Amount" both times and insert "Charge".
7. Sheet No. 792: strike "Financial penalties" and insert "Penalty charges".
8. Sheet No. 793: strike "Amount" both times and insert "Charge".
9. Sheet No. 794: strike "Amount" and insert "Charge".
10. Sheet No. 794: strike "financial obligation" and insert "penalty charge".
11. Sheet No. 795: strike "Amount" and insert "Charge".
12. Sheet No. 796: strike "Funds" and insert "Charges".
13. Sheet No. 796: strike "financial penalties" and insert "penalty charges".
14. Sheet No. 808: strike "financial penalty" both times and insert "penalty charge" and strike "penalty" both times and insert "charge".

Separately, we note that the cross-references in Sections 54.3.b and c in Module D to Section 38.8.4 in Module C appear to be incorrect, and we direct the Midwest ISO to revise them.

[195] A positive GSF also means that reduced production from that unit will cause reduced flows over the flowgate in question.

will cause a reduction in flows on the flowgate in question.[196] A generation resource's GSF is determined by the market models, and will reflect the topology of the system.

266. GSFs associated with a particular flowgate will vary among generators. GSFs are smaller for generators that are located more electrically distant from a flowgate (*i.e.*, further in physical distance or connected via lower voltage facilities). Thus, as Dr. Patton states in his testimony, most generators will only have a minimal impact on a given flowgate. The IMM will determine the appropriate GSF Cutoff for each flowgate. Dr. Patton argues that, on average, the GSF Cutoff should be 0.06 (six percent), but says that in some cases a different level may be appropriate. He testifies that the GSF Cutoff will be established such that generating units below the Cutoff are sufficiently generic in their ability to dispatch to resolve the constraint that it will be highly unlikely that they could warrant mitigation. For the generating units above the GSF Cutoff, they may or may not be able to exercise market power. Using these standards, the IMM will determine the appropriate GSF Cutoff at each flowgate, and adjust it as necessary.

267. A generation resource will be deemed to have a significant effect on the flowgate if the absolute value of its GSF is greater than that flowgate's GSF Cutoff. If the absolute value of the resource's GSF exceeds the GSF Cutoff, then when there is a binding constraint on a flowgate it will be included in the associated BCA and will be subject to conduct and impact tests. At that point, if it fails the conduct and impact tests, will it be subject to mitigation, as defined in the tariff. Generators with a GSF with an absolute value below the GSF cutoff will not be defined to be in the BCA, and thus will not be subject to the conduct and impact thresholds and thus will not be potentially subject to BCA mitigation.

### b) Protests and Comments

268. Detroit Edison and Cinergy advocate eliminating mitigation for BCAs. Detroit Edison believes the BCA definition is too vague and allows for open-ended authority to impose mitigation under impossible to ascertain standards. Cinergy believes the IMM has not shown that the market would not be competitive without BCA mitigation, and says BCA mitigation will unnecessarily interfere with Midwest markets. Cinergy testimony of Dr. Tabors says there has been no explicit finding of locational market power in BCAs and the GSF Cutoff process does not account for generation outside of the Midwest ISO that could mitigate against perceived market power. Cinergy says that the tariff does not indicate when or how generation owners will be notified that they will

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[196] A negative GSF also means that reduced production from the unit will cause increased flows on the flowgate in question.

be subject to potential mitigation if they exceed the conduct and impact levels. Generation owners could be penalized for "breaking rules they did not know to be in effect." Cinergy believes that BCA mitigation should be dropped, or the TEMT should require that the IMM provide notice to all affected generation owners when their generation is deemed to be within a BCA.

269. In contrast, Midwest TDUs believe that mitigation should be applied to areas of the Midwest ISO beyond NCAs and BCAs. Midwest TDUs argue that the safety-net bid cap will not protect these areas because market power can also be exercised during periods without scarcity such as with high demand with sufficient supply but with pivotal suppliers or concentrated ownership along portions of the supply curve. They say it is not clear why GSF Cutoffs are needed in addition to the conduct and impact thresholds, and that the GSF screen should be rejected because it may protect generators that are otherwise exercising market power as shown by conduct and impact tests. In addition, they say that the definition of GSFs is arbitrary, as are the cutoff values. The GSF methodology does not recognize the inter-relationships between GSFs, generator size, and degree of transmission congestion, and tells only part of the market power story. They point to the use of a percentage factor instead of a megawatt number in determining which generators can affect the flowgate, potentially inappropriately including some small players and excluding some with large effects on the flowgate. They say that another problem is that the GSF cutoff does not consider the megawatts needed to relieve the flowgate. The Midwest TDUs conclude that the appropriate GSF cutoff is zero.

270. In its Answer, Cinergy argues that proposals for a zero GSF cutoff and mitigation outside of BCAs amount to a call for round-the-clock, unrestrained mitigation. However, mitigation should be tailored to interfere as little as possible with the market when it is workably competitive. They also argue that the TDUs' proposed cap is so low that it is basically a call for return to cost-based rates.

### c) Discussion

271. The GSF approach to determining areas to be screened for anti-competitive conduct and impact has not been employed in any of the other RTOs. Its application leaves generators in some areas out of consideration for mitigation, without special filings by the IMM. Mitigation is applied in BCAs only when constraints are binding and when the bidder violates both the conduct and impact thresholds. However, this doesn't imply that the IMM will not monitor outside of NCAs and BCAs. The IMM will monitor all of the Midwest ISO system on an ongoing basis, and it will seek to enact mitigation if and when problems arise in areas that are not NCAs or BCAs. Focusing mitigation on NCAs and BCAs appropriately addresses market power where well-defined structural barriers to competitive performance exist.

272. While parties will likely not know in advance that constraints are binding, or if their offer will have an impact on the market price, they know their reference levels, and know when they are bidding in excess of their conduct thresholds. Bidders are not "penalized" for measures they do not know are in effect, they are informed of the rules of mitigation, and know that they are at risk of being mitigated anytime they offer in excess of the conduct thresholds. The thresholds of $100 or 300 percent above reference levels are not tight, because they are in areas that are not expected to have locational market power often, and thus they help avoid unnecessary mitigation. However, as stated in the March 13 Order, we do not take lightly buyer concerns that these measures will under-protect them.[197] Thus, we will closely review market assessments to determine if the thresholds are appropriate.

273. We find that built-in procedures for mitigation outside of BCAs and NCAs are not needed. Generators in areas expected to be competitive even under extreme system conditions should not be screened for mitigation as a matter of course. If the IMM observes market power problems, which are not captured within the BCAs and NCAs screening mechanism, the IMM should notify the Commission. We agree with Cinergy that there should be more transparency in the BCA process. In particular, we direct the IMM to coordinate with the Midwest ISO so that active BCAs and the associated flowgates are identified on the Midwest ISO website, as well as all prior BCAs and the associated flowgates.

274. The BCA approach, as filed, gives the IMM discretion to define GSF cutoff levels that it feels are required to determine which generators are included in the BCA We are particularly concerned about this discretion. We will require the IMM to use a default GSF cutoff of 6%. If the market monitor anticipates or observes problems using this cutoff for a particular flowgate, the IMM may notify the Commission so that the Commission may act under section 206 of the FPA, or the Midwest ISO may file under section 205 of the FPA with the Commission, to change the GSF cutoff, as appropriate, to include additional market players or exclude market players. We find that a GSF cutoff of zero, as requested by Midwest TDUs and Cinergy, would result in an overemphasis on screening units that have little or no impact on a specific flowgate. It is important to realize that the GSF analysis need not tell the entire "market power story." It is designed to be a first step in determining whether mitigation is needed in a BCA. The conduct and impact tests are to prevent unnecessary mitigation.

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[197] *See* March 13 Order at P 58.

275. We have, however, a few other concerns about the method of identifying which generators are included in BCAs via the GSF analysis. We share the concerns of the Midwest TDUs that the use of GSFs with a percentage factor rather than a megawatt number may leave out larger generators with smaller GSFs that nonetheless can have a major impact upon the flowgate in question. Likewise, very small generators with high GSFs may not have a significant impact on the flowgate and thus may not be able to exercise market power. However, we understand that the percentage of generation going through the flowgate in question may be an indicator of the profitability of an exercise of market power in the area. Also, the IMM may notify the Commission so that the Commission may act under section 206 of the FPA to change the GSF cutoff when it does not believe it is capturing the appropriate set of generators to address these problems. These are issues to which we will pay close attention. We will approve the use of BCAs as a method to screen for the use of mitigation in the Midwest ISO for a one-year period. During that period, the IMM will be required to submit quarterly reports with the Commission on BCAs and their associated mitigation to allow us to assess the BCA approach. Should we find problems with the IMM's discretion in the application of mitigation with BCAs, we will take appropriate action including consideration of terminating the BCA provision before the end of the one-year period. The Midwest ISO may file to extend the use of BCA mitigation beyond the one-year period, based on its analysis.

### 3. NCAs

#### a) NCA Definitions

##### *(1) The Midwest ISO's Proposal*

276. Annually, or more frequently as needed, the IMM will determine NCAs. An NCA is an electrical area defined by one or more transmission constraints that are expected to be binding for at least 500 hours during a given twelve month period, within which one or more suppliers is pivotal. A supplier is pivotal when the output of some of its generation resources must be changed to resolve the transmission constraint during some or all hours when the constraint is binding. In other words, it is pivotal when a binding transmission constraint cannot be relieved without changing the base loadings for other suppliers' generation resources.

277. NCA thresholds are intended to balance concerns that (1) locational market power could result in excessive market power costs if high region-wide thresholds are used, and (2) efficient economic signals must be established for new investment in generation and transmission in NCAs. Accordingly, NCAs are subject to tighter conduct thresholds for economic withholding in energy offers than BCAs, because they are expected to be subject to the potential exercise of market power more often. Conduct thresholds for physical withholding in an NCA are also tighter than in BCAs, with any physical

withholding in an NCA judged to be a violation of the conduct standard. If a constraint is binding and if the generator exceeds its reference offer by more than the conduct threshold or if it exceeds another conduct threshold (such as for another part of the offer, or another type of conduct such as physical withholding) and if impact on the market is to increase a price by more than the impact threshold, then mitigation will occur.

278. The IMM will seek comments from the Midwest ISO's market participants before altering or removing the designations of any area as an NCA. It will also make an informational filing with the Commission describing any change in the NCA designations, including the analysis supporting the change.

#### *(2) Protests and Comments*

279. A number of parties have concerns about the 500-hour minimum for constrained hours in the NCA definition. Midwest TDUs believe it is too high citing 375 peak hours.[198] Minnesota Entities argue that the 500-hour minimum should be rejected because significantly high prices in only a few hours in a year can harm consumers. They also argue that the Midwest ISO minimizes binding constraints and TLRs, and that relying on constrained hours to identify areas that may need mitigation will allow the exercise of market power. In contrast, PSEG argues that the 500-hour minimum is too low, at less than one-seventeenth of the hours in a year. It says that historical data on binding constraints may not be a good predictor. It states that if the Commission accepts the proposed NCA definition and thresholds, it should give the IMM less discretion, and allow only annual IMM reevaluation of congestion patterns and establishment of NCAs.

280. Midwest TDUs have several other issues with the NCA definition. First, they are concerned that suppliers may act in concert to exercise market power, even if none are independently pivotal. Thus load pockets where the generation ownership HHI exceeds 1800 should also be defined to be NCAs. Second, they believe the language in Section 64.3.1.e[199] requires the IMM to remove the NCA designation if the past year did not have 500 congested hours, even if 500 or more hours of congestion are expected in the coming year. Third, they feel the definition of pivotal supplier is too narrow. Currently, the supplier is only pivotal when a binding transmission constraint cannot be relieved through any possible variation of the output of other suppliers' on-line generation resources. They argue that including changes to output of rival suppliers in a way that

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[198] A 15-week summer peak period with constrained transmission during 5 hours of peak demand on weekdays would be 375 hours.

[199] The correct Section is 63.4.1.e, and the Midwest ISO should file to correct this cross-reference.

might be uneconomic or unreasonable results in an understatement of suppliers that should be considered pivotal. They also point out that a supplier could be non-pivotal by this definition even if the LMP would be raised substantially if the supplier withholds capacity. Southwestern says that when areas have LMPs that are consistently higher than those in unconstrained areas, they should be considered for NCA status.

281. OMS requests that Section 63.4.f be modified such that comments are also requested of interested state regulatory authorities before the IMM alters or removes the designation of any areas as NCAs.

#### *(3) Discussion*

282. We find that the 500-hour minimum for constrained hours is appropriate. A 500-hour minimum is used by ISO-NE, and it appears to set a good balance between mitigation and over-mitigation. We see no reason to apply a different standard in the Midwest ISO.[200] If the IMM determines that the expected constraints or hours of constraint are proving false, it can ask the Commission to redefine the NCA status, or lack thereof, of the flowgate. Its ability to do so is an important part of the mitigation program.[201]

283. We reject the argument that the definition of the NCA should include areas in which the HHI exceeds 1800. Such a change could result in excessive mitigation because

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[200] The 500-hour minimum threshold has been approved for a comparable purpose in New England with Designated Congestion Areas defined to be those with "annual congestion hours" not less than 500 or greater than 2000 hours. *See* New England Power Pool, *et al.*, 100 FERC ¶ 61,287 (2002).

[201] We have several problems with the Midwest TDUs' point that peak summer hours total only 375 hours, and thus the minimum number of constrained hours should be lower. First, constraints (as flagged by TLRs) are not generally related to peak system conditions. Instead they tend to occur when there are unexpected generator outages in one part of the system. Second, during peak system conditions, generators are likely to be running full force 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 prices may be high, but it is likely to be from system scarcity. Third, it is not clear that peak conditions are the optimal time for a generator to exercise market power. In doing so, they risk bidding so high as to not be selected, and to forgo the high scarcity prices in the market. In somewhat lower demand conditions the risks of bidding too high may be lower, and market power may be more likely to be exercised.

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 what the HHI is. However, we would encourage 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.

284. We also believe that the language in Section 63.4.1.e could lead to a misinterpretation, and require the Midwest ISO to change the language such that it is clear that the NCA distinction will be removed only if the transmission constraints defining the area are expected to be binding for less than the 500 hours, perhaps because they have been binding for less than the 500 hours in the past.

285. We believe the definition of pivotal suppliers is appropriate, while acknowledging that it is a tough standard to meet. The IMM's monitoring efforts should reveal any systematic problems which might result from this definition, and it should make recommendations to the Commission for any changes in the definition that are needed.

286. We reject the argument made by Southwestern that higher LMPs in a constrained area than in unconstrained areas means that area should be considered for NCA status. An area may be constrained but may have sufficient competitors within the area to be workably competitive.

287. Finally, we direct the Midwest ISO to modify its tariff to provide that it will notify the Commission and secure its approval before designating, or removing the designation of, any area as an NCA.

## b) NCA Identification and Designation

### *(1) The Midwest ISO's Proposal*

288. The IMM's testimony included analysis that designated specific NCAs within the Midwest ISO. To identify the NCAs, the IMM needed to identify: (1) at least one supplier within that area whose generation resources are pivotal in relieving congestion on one or more flowgates in that area; and (2) the transmission flowgate or flowgates that serve the area and which are expected to experience binding transmission constraints for at least 500 hours during a given year.

289. Pivotal suppliers are identified using transmission load flow cases. To determine if a supplier is pivotal, the IMM evaluated the GSFs for generators owned by the suppliers that affect the flowgate. The GSFs indicate the portion of a unit's incremental output that flows over the flowgate. Once the IMM determined the GSFs for all generating units for that flowgate, the total impact that supplier has on the flowgate can

be determined. Then changes in the supplier's output that maximize congestion on the flowgate are simulated. The impact of the additional flow on the flowgate is compared to the impact that all other suppliers have on it. If the individual supplier can cause a constraint even when other suppliers are treated as minimizing congestion (ramping units up or down, but not turning them off or on), the individual supplier is considered to be a pivotal supplier.

290. The IMM applied this methodology and tested each Midwest ISO market participant relative to each of the 121 flowgates that has been congested (having 10 or more hours of level 3a or higher TLRs) in 2002 and 2003.[202] The analysis focused on four seasonal cases, picking one month per season. It found one or more pivotal suppliers during at least one of the monthly cases on 51 distinct flowgates, with more than half of these associated with flowgates into or within the WUMS region. The analysis also found 28 flowgates with more than one pivotal supplier in one of the seasonal cases, and 29 flowgates with one or more pivotal suppliers in all four cases.

291. The next step was for the IMM to determine which of these flowgates will likely be congested for 500 hours or more on a yearly basis. The IMM used Transmission Loading Relief (TLR) data and data from the Midwest ISO's flowgate monitoring tool to estimate likely hours of congestion given hours of congestion in the past. The analysis found a number of flowgates meeting these criteria in the WUMS and North WUMS regions, and two flowgates outside these regions. Once Day 2 markets are up and running, LMP market data will replace TLR data in the determination of constrained hours.

292. The two non-WUMS or North WUMS flowgates are (1) Rocky Run-Northpt+Weston-Rocky Road and (2) Arnold Vinton 161 kV for contingency on D. Arnold-Hazelton 345 kV. In the case of the Arnold Vinton 161 kV for contingency on D. Arnold-Hazelton 345 kV, there is a pivotal supplier in only one of the four cases, and the supplier would have to withhold 78 percent of its base output to be pivotal. For the Rocky Run-Northpt+Weston-Rocky Road flowgate, the congestion is a local constraint associated mainly with a single generator. The IMM believes that the potential price effects of this are small and that market power would be unlikely in this instance. Accordingly, the IMM did not identify any NCAs associated with these two flowgates.

293. The IMM defined the WUMS areas and the Northern WUMS area as two distinct NCAs. The WUMS NCA includes 15 flowgates that significantly limit imports into WUMS. The Northern WUMS NCA is defined to include 12 flowgates that limit imports

[202] With a TLR level 3a, non-firm transactions in the next hour are curtailed.

into northern Wisconsin and the Upper Peninsula of Michigan. In determining which flowgates belong in the same electrical area, the IMM evaluated combinations of flowgates to determine the potential for multiple-flowgate NCAs. If the flowgates affected common electrical facilities, then anytime one of those flowgates experiences a binding constraint, they count the hour as a constrained hour. If other flowgates in the NCA are constrained that hour, the count of binding hours is unchanged.

### *(2) Protests and Comments*

294. Midwest TDUs say the analysis should identify the specific generators in the NCAs. They also say that the IMM did not submit supporting work papers and data. They say the market analysis overlooks flowgates where binding constraints occur, especially within WUMS. The designation of NCAs leaves out six flowgates the IMM lists as being within WUMS and with pivotal suppliers in at least one of the four cases. The analysis also leaves out 21 inter-WUMS or WUMS boundary flowgates that do not appear in the market analysis but that experienced level 3 or higher TLRs in the past month. These additional flowgates should be analyzed for NCA status. Midwest TDUs are also concerned that binding flowgates within WUMS that do not exclude imports into WUMS are not being considered. They state that if distinct sub-areas of WUMS can be distinct load pockets the IMM should include them as NCAs.

### *(3) Discussion*

295. In the Market Rules Compliance Order, the Commission said that it expected any future filings designating NCAs to address all components of the NCA definition including the number of suppliers for individual or specific flowgates, number of constrained hours, cost data of generators, and any other market characteristics that are incorporated into the process of designating an NCA.[203] The IMM filed a market analysis designating the NCAs along with his testimony in this proceeding.

296. The analysis performed by the IMM finds only two flowgates that meet the definition of a NCA and that are not within the WUMS or Northern WUMS region. We question the IMM's assertion that flowgate Rocky Run-Northpt+Weston-Rocky Road should not be an NCA because it is expected to affect only a localized area and price effects are likely to be small. We are concerned about the exercise of market power even if it is in a limited geographic area or associated only with one supplier. We direct the IMM to clarify why this flowgate should be omitted from a NCA status.

297. As the Midwest TDUs point out, the text of the IMM's analysis submitted with his testimony lists the flowgates that significantly limit imports into WUMS and North

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[203] Market Rules Compliance Order at P 31.

WUMS. It does not, however, include six flowgates that are included in Table A-1 of Appendix A of that analysis, which details flowgates into and within WUMS.[204] However, we notice that six other flowgates are listed twice in the text of the market analysis, and we believe that this may be an editorial error.[205] The IMM must clarify in a compliance filing why the six flowgates in the Appendix but not the list of flowgates associated with the WUMS and North WUMS NCAs should be omitted, or revise the list of flowgates to include them. We also direct the IMM to identify in that compliance filing all units that, under the current proposal, will be subject to NCA thresholds. The IMM should make this filing within 60 days of the date of this order.

298. Beyond these six flowgates, if intervenors believe additional flowgates should be incorporated in the IMM's analysis, the intervenors must specifically list the flowgates in question and submit a request to the IMM for it to determine whether these flowgates should be included in the analysis. To the extent the intervenors offer supporting information and/or analysis that indicates how the inclusion of these flowgates would alter the proposed NCA designation, and thus how it might affect mitigation, this will aid the IMM in choosing any analysis it will complete. We note that if the flowgates in question are within relatively close electrical proximity to flowgates presently identified by the IMM as meeting NCA criteria, the generators subject to mitigation with NCA thresholds may not be altered.

### 4. Reference Levels

#### a) The Midwest ISO's Proposal

299. Under the Midwest ISO's proposal, conduct thresholds are added to reference levels for an individual generator to determine if it is behaving competitively. They serve as a competitive benchmark when the conduct tests are applied. Reference levels are based upon estimates of the generator's marginal costs, including legitimate risks and opportunity costs. Reference levels for a unit vary over its output range, with an energy reference level calculated for each 10 MW output segment for most units. Reference

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[204] These include Stiles-Amberg 138 for Morgan-Plains, Stiles-Pioneer for N.Appl-WhiteClay 138, Green Lk-Roeder 138 for N Appleton-Ror, N.Appleton-Lostdauphin 138 for Kewaunee Xfrm, and Kewaunee 345/138 Xfrm, Kewaunee Xfrm-N Appleton.

[205] These include Flow South, Highway V-Preble 138 Flo Lost Dauphin-Red Maple, Highway V-Preble+N Applton-White Clay, N Appleton-Wh Clay 138 For Stiles –Pulliam 138, Stiles4-Pulliam 138+Stiles5-Pulliam 138, and Stiles-Amberg & Stiles-Crivitz Flo Morgan-Plains.

levels are also calculated for all other applicable components of offers such as start-up costs, minimum generation costs, and the physical parameters of each unit.

300. The proposed TEMT sets three methods (in order of application) for calculating a unit's reference levels: (1) offer-based, (2) LMP-based, and (3) consultative. The offer-based method uses the lower of the mean or median of a unit's accepted offers in competitive periods over the previous 90 days for similar hours, adjusted for fuel prices. The LMP-based method uses the mean of the LMP at the unit's location during the lowest priced 25 percent of the hours that the unit was dispatched over the previous 90 days for similar hours (*i.e.*, peak or off-peak), adjusted for changes in fuel prices. Dr. Patton states in his testimony that for natural gas and oil-fired units, changes in fuel prices will be incorporated daily. The consultative method determines the level by consultation with the market participant in question, and is intended to reflect a unit's marginal costs, including legitimate risks and opportunity costs, or justifiable technical characteristics for physical offer parameters, provided such consultation has occurred prior to the occurrence of the conduct being examined. If sufficient data do not exist to allow calculation of a reference price based on the first two methods and the third is not applicable, or an attempt to determine a reference level in consultation with the market participant has failed, the IMM shall determine the reference level on the basis of: (1) the IMM's estimate of the costs of a Generation Resource or its technical characteristics; or (2) an appropriate average of competitive offers of one or more similar generation resources.

301. When the market begins operation, there will be neither a history of accepted offers nor LMPs. Thus a transitional mechanism for the determination of appropriate reference levels will be needed. The IMM proposes that it issue a standardized survey form to each supplier in order to gather the data needed to develop a consultative reference level for each supplier. For units not submitting the data, the IMM will estimate their variable production costs from publicly available data or set their reference levels based on an average of similar units.

### b) Protests and Comments

302. Southwestern argues for the use of variable production costs instead of opportunity costs because the latter are subjective. Similarly, it argues for using prior period data rather than cumulative based prices[206] when sufficient data is not available to calculate the reference price, because the latter is subjective and subject to manipulation.

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[206] We assume for purposes of the discussion that Southwestern meant "consultative."

Cinergy argues that the proposed designation of reference levels in BCAs fails to clearly acknowledge the high-cost output segments of many generation resources.

303. The Midwest TDUs believe that purchasers should have access to the reference levels, and have input in setting them. They say that such access would build confidence in market outcomes and help to deter abuses by sellers who might otherwise take advantage of the lack of scrutiny. WPS Resources says the TEMT should include a process by which appeals can be made on reference levels.

### c) Discussion

304. We will accept the approach proposed in the TEMT for calculating reference levels. The methods used are similar to those approved in other markets that mitigate through conduct and impact thresholds.[207] We also believe that the use of opportunity cost data in establishing reference levels is important. While such opportunity costs may be somewhat subjective, they are still true costs, and should not be left out. However, we believe that the process of determining the reference levels should be laid out in more detail. In that regard, we order the IMM to file with the Commission to more clearly specify what factors it considers in the marginal cost calculation in order to include legitimate risks and opportunity costs in establishing reference prices.[208] The IMM should also discuss how these costs are estimated for different output levels.

305. We also believe that the tariff language in Section 64.1.4.c clearly establishes that reference levels may vary over the output range of the generation resource, and thus dismiss Cinergy's concerns on this issue as misplaced.

306. We reject the Midwest TDUs' argument that purchasers should have access to, and input in, setting the reference levels. The IMM should independently establish the reference levels, relying on the methods specified in the tariff. Information on generators' costs should not be available to other market participants. The consultation process can be used by the generator in question when it has concerns about the appropriate reference level. Any party may present information to the IMM or to the Commission, either publicly or on a confidential basis.

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[207] *See*, *e.g.*, New York Independent System Operator, Inc., *et al.*, 99 FERC ¶ 61,246 at 62,045 (2002).

[208] Examples might include fuel costs at different output levels, risks of breakdown at certain levels of output, and costs of repairs, as well as the opportunity cost of not being able to run the unit while it is down.

### 5. Threshold Levels

#### a) The Midwest ISO's Proposal

307. The TEMT establishes threshold levels for offers and other variables for behavior subject to mitigation. These thresholds are the limits that the parameters may rise to, over the reference levels, without being subject to mitigation. The thresholds are tighter in NCAs than for BCAs, because the exercise of market power is more likely on a recurring basis in NCAs.

308. Conduct thresholds for economic withholding are provided for multiple portions of the energy offer. In particular, there are thresholds for energy, startup costs, time based parameters, and other parameters, as shown below.

| | BCAs | NCAs |
|---|---|---|
| Energy | Lower of 300 percent increase or $100/MWh; minimum $25 MWh offer | [Net annual fixed cost / constrained hours] |
| Startup costs | 200 percent increase | 50 percent increase |
| Time-based parameter | Increase of three or six hours in total for multiple such parameters | Same as BCA |
| Parameters other than time | 100 percent increase for minimum parameters or 50 percent decrease for maximum parameters | Same as BCA |

309. As shown in the table, for energy offers in NCAs, the conduct threshold is the ratio of net annual fixed cost to the constrained hours in the NCA. In this ratio, the net annual fixed cost is defined to be the annual fixed costs of a new peaking generator per MW, including the recovery of capital costs, minus appropriate credits for net revenue the new generator would receive from the markets and services provided under the tariff and any applicable resource adequacy mechanism. Constrained hours is the total number of hours over the prior twelve months in which a binding transmission constraint has occurred on any interface into the NCA in which the generation resource is located, but not more than 2,000 hours.

310. In BCAs the conduct threshold for physical withholding is withholding more than the lower of 5 percent or 200 megawatts, or having a real-time output level that is less than 90 percent of dispatch instructions. In NCAs the conduct threshold is zero, meaning that any withholding results in a failure of the conduct test. In the calculation of physical withholding levels, economic withholding is added in to come up with a total amount withheld for application of the threshold. Economic withholding is not included in the total for physical withholding used to determine sanctions, however.

311. Conduct thresholds for uneconomic production are a unit being scheduled when the LMP is less than 50 percent of its reference level or it having a Real-time output of greater than 110 percent of dispatch instructions. This threshold applies in both BCAs and NCAs. There are no specific conduct thresholds for uneconomic market participant bidding or for virtual transactions.

312. Impact thresholds set limits on the acceptable impacts on prices or on offer revenue sufficiency guarantee payments to market participants in the energy markets or other markets administered by the Midwest ISO. Impact thresholds do not depend on the type of behavior involved, but do vary between BCAs and NCAs. For BCAs, the threshold is an increase of the lower of 200 percent or $100/MWh. In the case of NCAs, the threshold is the same as the conduct threshold for energy offers which is the net annual fixed cost divided by the constrained hours. The conduct threshold for economic withholding associated with energy offers and the impact thresholds for NCAs are the same: The net annual fixed cost divided by the constrained hours.[209]

### b) Protests and Comments

313. PSEG argues that the threshold for NCAs will cause too much mitigation in a nascent market with only 500 hours of binding constraints and a single pivotal supplier qualifying as an NCA. Others believe that the thresholds are too high. Midwest TDUs say that to avoid over-recovery of generator costs and overcharging rate payers, the fixed cost adder (for NCAs) must be clarified if the fixed cost adder is not netted for all sources of fixed cost recovery. They believe a 10 percent threshold above marginal costs (including legitimate and verifiable opportunity costs) should be applied to NCAs with sufficient capacity, but where suppliers are concentrated, as signals for additional investment are not needed. They also argue that NCA thresholds should not exceed BCA

[209] The net annual fixed cost is the fixed cost of a new peaking generator minus revenue from applicable resource reserve adequacy payments. Alternatively, the net annual fixed cost is also equal to the revenue per MW that a new peaking generator would need to earn in excess of the net revenue it can expect to receive from Midwest ISO electricity markets to cover its fixed costs, including a return on equity. The number of constrained hours (the denominator for the threshold) is limited to 2000 hours. The 2000 hour limit is used because the formula is designed to allow for the recovery of the costs of a new peaking generator. Dr. Patton testifies that in most cases, it would be unrealistic for a new peaking generator to run for more than 2000 hours in a year. Patton testimony at 54.

thresholds. The Wisconsin Retail says lower thresholds should be implemented across the board and they advocate a cost based approach of marginal cost plus 10 percent, where appropriate.

314. Southwestern believes that the BCA thresholds for physical withholding should be the lower of 5 percent or $50/MWh. Likewise, the threshold for economic withholding should be the lower of 200 percent or $50. Midwest TDUs point to thresholds in "similar areas of New England," in arguing BCA thresholds should be decreased to the lower of 50 percent or $25.

### c) Discussion

315. We find that the thresholds proposed by the Midwest ISO are appropriate. They are very similar to those adopted in both NYISO and ISO-NE, especially in areas with low to moderate market power concerns, such as BCAs. These markets share a common philosophy of market power mitigation with conduct and impact tests, and their associated thresholds are almost identical to those proposed by the Midwest ISO. To the extent that the thresholds for physical withholding are higher in the Midwest ISO as flagged by the Midwest TDUs, we recognize that significant differences exist between the Midwest ISO and these other markets. The IMM's 2003 State of the Market Report for the Midwest ISO shows that generation resource capacity in the Midwest ISO footprint is more than adequate with a resource margin of 20 percent.[210] Also, while the ISO-NE market has an Installed Capacity market that allows generators an opportunity to recover some of their fixed costs, the Midwest ISO does not yet have an organized reserves market with capacity payments and thus it would not be appropriate to lower the thresholds to the lower of 50 percent or $25.

316. As the Commission stated in the Market Rules Rehearing Order, mitigation is counterproductive to the extent it penalizes suppliers trying to resolve constraints, and when their higher offers reflect higher costs, not manipulation.[211] Over-mitigation can inadvertently cause reliability problems to the extent that it keeps capacity out of the market over the longer term. Thus a range of pricing needs to be accepted that ensures suppliers can offer and mitigation does not hinder that bidding. Past offers or a marginal cost estimate plus a set percentage may not reflect the costs that are incurred at the hour of the binding constraints.

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[210] Potomac Economics, Ltd., 2003 State of the Market Report: Midwest ISO at 2 (2003), *available at* www.potomaceconomics.com/serv01.htm .

[211] Market Rules Rehearing Order at P 35.

317. In response to the Midwest TDUs' comment, two concerns are balanced in developing thresholds for NCAs: (1) locational market power, and (2) efficient economic signals for investment in generation and transmission in the NCA. The fixed cost adder provides a careful balance between the need to mitigate market power and to provide an efficient incentive to invest. As a result, it should not be replaced by the BCA threshold in circumstances in which the latter is lower.

### 6. Behavior Subject to Mitigation

#### a) The Midwest ISO's Proposal

318. The proposed TEMT states that the following categories of conduct, whether by a single firm or multiple firms, may warrant mitigation: physical withholding of an electric facility, economic withholding of a generation resource, uneconomic production from a generation resource, and uneconomic market participant bids or virtual transactions. In general, the IMM will consider a Market Participant's conduct to be inconsistent with competitive conduct if it would: (1) reduce the net revenue associated with the electric facility, but for the conduct's effect on market outcomes; or (2) inefficiently reduce the capability of the transmission system.

319. The TEMT defines physical withholding to be not offering to sell or schedule the output of or services provided by an electric facility capable of serving an energy market or any other Midwest ISO-administered market. Such withholding may include: (1) falsely declaring that an electric facility has been derated, forced out of service or otherwise become unavailable; (2) refusing to provide offers or schedules for an electric facility; (3) operating a Generating Resource in real time to produce an output level that is less than the dispatch instructions; or (4) operating a transmission facility in a manner that is not economic, is inconsistent with Good Utility Practice, or causes or contributes to a Binding Transmission Constraint.

320. Economic withholding is submitting offers that exceed the conduct thresholds for economic withholding established in the TEMT that cannot be justified, so that: (1) output from the generation resource is not or will not be dispatched or scheduled; or (2) the offers will clear at prices that are significantly above competitive levels.

321. Uneconomic production is increasing the output of a Generation Resource to levels that would otherwise be uneconomic in order to cause or contribute to a Binding Transmission Constraint.

322. Uneconomic market participant bids or virtual transactions entails submitting an offer in the Day-Ahead energy market that is not economically justified based on risk management or other economic considerations, and that causes or contributes to substantial divergence between prices in the Day-Ahead and Real Time energy markets.

### b) Protests and Comments

323. FirstEnergy states that the general guidance on underproduction (withholding) is too broad, not defining the period over which the conduct would reduce net revenue. It argues that the plant operator may decide to produce more now than later in the year in order to maximize revenue later in the year.

324. Dynegy believes that mitigation for physical withholding of an electric facility if it is capable of service in an Energy Market must be rejected because the TEMT imposes a "must offer" requirement only on Designated Network Resources. Reliant Energy says the definition of physical withholding should make clear that only resources designated under Module E are obligated to provide offers or schedules to the Midwest ISO. Detroit Edison says that the physical withholding provisions should only apply to the Real-Time Market. It says that the threshold of the lower of 5 percent or 200 megawatts is inconsistent with Good Utility Practice because market participants need to reserve capacity on a day-ahead basis to provide contingencies for unexpected generation outages and variations from forecast load, but can make any such capacity that is not needed available in the Real-Time Market.

325. FirstEnergy argues that the TEMT should not establish "uneconomic production" as a new type of anti-competitive activity without sufficient justification and a clearer definition of it. It says that uneconomic production in order to create or maintain a transmission constraint, is too broad, as it is hard to know the effect of the action in advance. It also argues against the definition of uneconomic production of scheduling production at a location at which "LMP is less than 50% of the reference level," saying there may be an equipment failure and plant operators may need to keep the output steady until repairs occur. FirstEnergy also states that the second part of the uneconomic production test, where output exceeds 110 percent of dispatch instructions and is causing or maintaining congestion, may conflict with NERC rules that require operators to balance supply with demand using ten minute averages. They allege that the same problem exists in defining physical withholding as producing less than 90 percent of dispatch instructions.

326. FirstEnergy and AMP-Ohio argue that the language on the degree of divergence that will be allowed between the Day-Ahead and Real-Time Markets gives the IMM too much discretion. AMP-Ohio states that the tariff has the IMM determining when under-scheduling is an operational problem, but the Midwest ISO should do so. It also states that the potential existence of operational problems appears to be ignored, given the IMM's testimony: ". . . If the IMM determines that such actions [sustained under-bidding] are contributing to a divergence between Day-Ahead and Real-Time Markets,

the IMM may require the market participant to schedule a minimum percentage of its load in the Day-Ahead Market."[212]

### c) Discussion

327. The types of conduct subject to mitigation are appropriate. They are very similar to the categories defined as subject to mitigation in both NYISO and ISO-NE. However, we do not believe that the Midwest ISO has defined some of the types of conduct subject to withholding in a manner that includes clear, objectively quantifiable standards. Recent Commission decisions have authorized market monitors to enforce certain tariff matters only if those matters are expressly set forth in the tariff and if they involve objectively identifiable behavior.[213] Thus, these definitions must include clear, objectively identifiable criteria before mitigation can be implemented by the Midwest ISO in conjunction with the IMM. We believe that in the definition of physical withholding, the concepts of what actions constitute false deratings or inappropriate outages or unavailability of a unit should be defined.[214] In addition, the definition is not clear enough on what the operation of a transmission facility in a manner that is inconsistent with "Good Utility Practice" means. Further, it is not clear that operating a transmission

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[212] AMP-Ohio at 28 (citing Patton testimony at 40).

[213] They must also not subject the seller to sanctions or other consequences other than those expressly approved by the Commission and set forth in the tariff. *See* Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 105 FERC 61,218, *clarified*, 105 FERC ¶ 61,277 (2003), *order on reh'g*, 107 FERC ¶ 61,175 (2004). *See also* California Independent System Operator Corporation, 106 FERC ¶ 61,179 (2003), *reh'g denied*, 107 FERC ¶ 61,118 (2004), *reh'g pending* (permitting the California ISO's market monitor to administer certain behavior-related tariff provisions and to charge penalties for certain behavior).

[214] Elsewhere in this order, we direct the removal of the phrase ", but is not limited to," from Section 63.3.a.i.

facility in a manner that "causes or contributes to a Binding Transmission Constraint",[215] is sufficiently limited to justify the definition of physical withholding.[216] The Midwest ISO must file to clarify what these concepts and phrases mean.

328. In response to FirstEnergy's concern, we find that the definition of withholding need not specify the term over which withholding would be profitable. The IMM should be able to look for the exercise of market power across periods, and justify its finding if appealed.

329. We do not agree that the definition of physical withholding needs to be changed to reflect concerns about there not being must-offer requirements for generators beyond Module E. The Commission's previously-stated concerns on this issue relate to the earlier Midwest ISO proposal which had financial penalties for physical withholding in the Day-Ahead Market and the RAC process in the Real-Time Market, generating the equivalent of a must-offer condition without an associated capacity payment.[217] The TEMT has been modified to provide that physical withholding financial penalties shall not be applied to the generators in the Day-Ahead Market or the RAC process that are not designated to satisfy resource adequacy requirements under Module E. Physical withholding will apply to designated resources that fulfill state or regional reliability requirements as discussed in the Resource Adequacy section of this order. The IMM should keep data on physical withholding when financial penalties are not to be collected, and file that information in its annual report. Because parties will not be penalized without the equivalent of a capacity payment, and because of our concerns stated above, we decline to change the definition of physical withholding on this issue.

330. Detroit Edison need not be concerned that the physical withholding determination and thresholds will be inconsistent with Good Utility Practice in the Day-Ahead Market. We do not believe that withholding resources from the Day-Ahead Market by individual utilities is needed in order for them to provide for contingencies for unexpected generation outages and variations in actual load from forecast load. Having the utilities offer or schedule their network generation resources in the Day-Ahead Market is

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[215] Elsewhere in this order, we direct the removal of "or contributes to".

[216] The language specifying "or" implies that this is a sufficient condition on its own. However, there may be circumstances under which operation of a transmission facilitycauses a binding transmission constraint in one area of the system, but helps in another area.

[217] *See, e.g.*, Market Rules Rehearing Order at P 26.

consistent with a utility's past practice of holding some surplus generation in reserve (rather than selling it through the bilateral market) to account for unplanned outages or forecast errors (as distinct from contingencies for which operating reserves are formally required). Under the proposed market: (1) all operating reserves are acquired as before through the control area operator; (2) forecast errors become the Midwest ISO's responsibility, for which it conducts the RAC; and (3) unplanned outages can be planned for in several ways without physically withholding generation until real time. First, if the utility has excess power that it wants to hold in reserve for real time, it can do so by raising its price in the Day-Ahead Market (within the mitigation thresholds that apply at that location). Second, it can "virtually" buy some additional power in the Day-Ahead as a hedge, *e.g.*, it can buy the expected (average) outage amount, say 100 MW, and "sell" it back in real time if not needed. Third, it can rely on purchasing from the regional spot market. It can achieve these without engaging in physical withholding as defined in the TEMT.

331. We note that Section 64.3 of the TEMT establishes a process between the IMM and the party which fails conduct and impact screens and would otherwise be subject to mitigation, to allow the Market Participant to explain the conduct. Section 64.3.b says that if the market participant's explanation of the reasons for the conduct indicates to the satisfaction of the IMM that the questioned conduct is consistent with competitive behavior, no further action will be taken. This language appears to cover the case of uneconomic production flagged by FirstEnergy, where the conduct test is failed due to the plant operator exceeding its dispatch instructions when it has an equipment failure, and needs to keep the output steady to avoid damaging the equipment.

332. We disagree with FirstEnergy's argument that the Market Participant must know the impact of its actions in advance for uneconomic production to be found. That an action results in or adds to a binding constraint is like an impact test used for physical or economic withholding. Market participants that engage in conduct that fails the conduct test do not generally know in advance that they will fail the impact test, yet they are subject to mitigation if they do. There is no real difference in this case, so these concerns are groundless. We also do not believe that the IMM must show the *intent* of a market participant to cause such a constraint, in order for there to be a finding of uneconomic production. Thus, we will require the Midwest ISO to amend its definition of uneconomic production to replace the phrase "in order to cause or contribute to a Binding Transmission Constraint" with "and that causes a Binding Transmission Constraint."

333. In response to FirstEnergy's concern about compatibility with NERC balancing rules, this problem has not arisen in other ISO markets with similar rules. Thus, FirstEnergy's argument is speculative, and we will not address it at this time. If a conflict does arise, it should be brought to the Commission's attention promptly.

334. We agree with FirstEnergy and AMP-Ohio that the IMM has excessive discretion in determining the appropriate degree of divergence between Day Ahead and Real Time Market prices. We direct the Midwest ISO to establish clear, objectively identifiable standards for what constitutes an improper balance between bidding in the Day Ahead and Real Time market.

335. In response to AMP-Ohio's concern about the IMM determining when there are operational problems due to the balance of bidding between Day-Ahead and Real-Time Markets, we appreciate the concern that it is the Midwest ISO rather than the IMM that will deal with operational problems. However, we note that there are a number of other factors to be considered for which the IMM, in the first instance, is the appropriate party to conduct the analysis. These include: (1) the determination that the relationship between the LMPs at a location in the Day-Ahead and Real-Time Markets is not what would have been expected under conditions of workable competition, (2) one or more market participants have been purchasing a substantial portion of their load in the Real-Time Market, and (3) that this practice has contributed to an unwarranted divergence of LMP between the two markets. Having the IMM coordinate all the associated analysis is important. Thus, we direct the Midwest ISO to amend Section 65.4.2.d to provide that the IMM should determine the existence of operational problems in concert with the Midwest ISO.

336. Section 65.2.2.e provides: "A Mitigation Measure imposed in a Narrow Constrained Area in accordance with the conduct thresholds of Sections 64.1.1.a or .b and the impact thresholds of Section 64.2.1 shall remain in effect for the duration of any hour in which there is an interval for which such mitigation is deemed warranted." Section 64.1.1a establishes the thresholds for physical withholding of a generation threshold. However, Section 64.1.1.e provides that Section 64.1.1.a does not apply to the identification of physical withholding by a Generation Resource in an NCA, and thus applies to withholding within a BCA. The Midwest ISO is directed to clarify or correct the tariff language in Section 65.2.2.e such that it is evident which mitigation measures are to remain in effect for the duration of any hour in which there is an interval for which such mitigation is deemed warranted. In particular, the Midwest ISO should make clear what type of withholding Section 65.2.2.e applies to, and whether it applies to BCAs, NCAs or both.

### 7. Binding Constraints as a Prerequisite for Mitigation

#### a) The Midwest ISO's Proposal

337. In determining if the behavior of one or more market participants should be mitigated, the IMM's first step is to find binding constraints that affect the areas. If there are none, then the standard mitigation analysis stops. If there are such constraints, the

next step is to see if these constraints exist within NCAs or BCAs. If there are no constraints on the system, there is no mitigation unless the requested mitigation is approved by the Commission.

#### b) Protests and Comments

338. Southwestern states that market monitoring and market power mitigation is important at all times, not just when markets are constrained, as manipulation can occur during periods without constraints.

#### c) Discussion

339. We agree with Southwestern that market monitoring is important at all times. However, different levels of market monitoring and market power mitigation are appropriate under different circumstances. Because of the large number of sellers in the Midwest ISO, without system constraints the exercise of market power is very unlikely. However, we emphasize that the IMM should monitor throughout the Midwest ISO for market problems, and let the Commission know if there are circumstances under which mitigation is needed when constraints are not involved.

### 8. Prospective Application of Mitigation

#### a) The Midwest ISO's Proposal

340. In the March 13 Order, the Commission rejected tariff provisions that included automated mitigation procedures, finding those provisions to be premature given the IMM's determination that they are not necessary at the beginning of Day 2 operations. In addition, we cited to the IMM's lack of software for such procedures. However, we stated that our rejection of the procedures was without prejudice to a future filing to implement such provisions when the IMM determines they are necessary.[218] In its rehearing order, the Commission said that it was not dissuaded from its earlier finding that the mitigation measures, as then proposed, would ensure just and reasonable rates in the Midwest ISO.[219]

341. The TEMT proposes prospective application of mitigation in both the Day-Ahead and Real-Time Markets. The IMM says that, in the case of the Day-Ahead market, mitigation will occur the following market day. This means that bids that fail the conduct

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[218] March 13 Order at P 105.

[219] *See* Market Rules Rehearing Order at P 60.

and impact tests will remain unmitigated for the first day that the generator fails. In the case of the Real-Time market, bids will be mitigated within 2 to 3 market intervals (10-15 minutes).

### b) Protests and Comments

342. Several parties raise concerns about the prospective application of mitigation measures. Southwestern states that prior conduct may warrant the automatic implementation of mitigation measures, which are necessary even when the potential for the exercise of market power is determined. In NCAs, Southwestern believes that mitigation measures should be triggered automatically when market conditions require a rapid response. In general, it suggests that long term mitigation measures should include transmission expansion on an expedited basis.

343. Of particular concern to some parties is the use of prospective mitigation in the Day-Ahead Market. Midwest TDUs note that sellers essentially must fail the conduct test twice before mitigation measures are applied, while offers that violate the mitigation measures are not remedied. They say that this gap must be plugged through either automation or expedited manual mitigation, and that not doing so cannot be justified on the grounds that market power concerns are believed to be lower in the Day-Ahead Market. Damage will be done before parties could switch to the Real-Time market, and parties switching to that market could adversely affect FTR values, making them a less effective hedge. Coalition MTC rejects Dr. Patton's testimony that market power concerns are lower in the Day-Ahead Market. It also questions why mitigation can occur within 15 minutes in the Real-Time Market, but a full day is allowed to elapse before mitigation in the Day-Ahead Market.

### c) Discussion

344. While Real-Time Markets could mitigate much of the potential for the exercise of market power in the Day-Ahead Market, we are concerned that some exercise of market power there can still occur. Given potential limits of parties under-scheduling, and bidding largely in the Real-Time Market, we share the concerns about the prospective application in the Day-Ahead Market, as it may provide an opportunity for the unmitigated exercise of market power. Given these legitimate concerns, we direct 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.

### 9. Duration of Mitigation

#### a) The Midwest ISO's Proposal

345. Any mitigation measure imposed will expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as specified by the Midwest ISO.

#### b) Protests and Comments

346. Southwestern says that the TEMT should be revised to eliminate the restriction of mitigation measures to six months. It believes that the restriction is arbitrary and unsupported, and that the mitigation measures should be in effect for as long as the conditions giving cause to the measures remain.

#### c) Discussion

347. We believe that mitigation procedures should not continue indefinitely. However, neither should mitigation measures be removed when problems remain that would justify that mitigation. This same duration limit of six months for mitigation has also been applied in ISO-NE and NYISO without any major problems. The six-month limitation does put some pressure on the parties to effect longer-term structural solutions to any market power problems. In addition, after the six-month period, we see no reason that the IMM could not ask the Commission for authority to reapply the mitigation if it is needed, or if the problem resurfaces. For this reason, we are willing to let it stand for now, but ask that the IMM notify us if it sees problems that need continued mitigation beyond the six-month window, that cannot be resolved readily in another manner.

### 10. Sanctions

#### a) The Midwest ISO's Proposal

348. If the IMM determines, in accordance with the thresholds and other standards in Module D, that a Market Participant has engaged in physical withholding or uneconomic production, the Midwest ISO will impose financial penalties. Generation Resources that are not designated to satisfy the resource adequacy requirements under Module E are not subject to financial penalties for withholding from the Day-Ahead Market or RAC process. The TEMT allows for the Midwest ISO to impose financial penalties or sanctions in cases where a load-serving entity has under-bid in the Day-Ahead Market and caused consequences detailed in Section 65.4.2.d. Financial penalties may also be applied to a transmission owner that has taken unjustified actions that cause transmission congestion, including operating network control devices in a manner that is inconsistent with Good Utility Practice and that is uneconomic. The behavior in question must fail both the conduct and impact tests, and be within an NCA or a BCA that is associated with a binding constraint, to be subject to the specified penalties or other sanctions.

349. Penalties and sanctions are targeted at market power abuses that cannot be dealt with prospectively, such as physical withholding that can only be identified *ex post* through investigations and audits. Financial penalties are the product of a base penalty amount and a multiplier. The base penalty amount is the penalty LMP times the capability affected during penalty hours, where the capability affected is the megawatts physically withheld, uneconomically produced, underscheduled or the transmission capacity reduced. The multiplier depends upon the number of violations the Market Participant or its affiliates has already had. It is one for the first instance of a type of conduct meeting the standards for mitigation. For the second instance within eighteen months of substantially similar conduct, the multiplier is two. For the third instance within eighteen months, the multiplier is three. Penalties will be credited against costs collectable under the tariff.

350. In the case of load underbidding by a Market Participant purchasing on behalf of a load-serving entity in the Day-Ahead Market, the sanction may be requiring the participant to purchase or schedule all or a specified portion of its expected power requirements in the Day-Ahead Market. Similarly, the Midwest ISO may limit the hourly quantities of virtual offers or bids for supply or load that may be submitted by a Market Participant, when conditions specified in the TEMT are met.

### b) Protests and Comments

351. Southwestern states that penalties should be sufficient to have a deterrent effect on market manipulation, but says that it is unclear if the proposed penalties are at that level. In contrast, FirstEnergy notes that the base penalty is the full amount of the LMP at the relevant bus, instead of the difference between the actual LMP and the "but for" LMP, when the difference would restore the competitive result. As a result, the penalty is, in fact quite substantial and goes far beyond making market participants whole, especially if doubled or tripled. They argue that the Commission should provide for *de novo* review of the imposed penalties, with the burden of proof being on the IMM. Market power mitigation rules should include clear and specific standards of review and should preserve due process. In addition the lack of specificity in the definition of "substantial" in "substantial increase in one or more prices…," leaves the market monitor with broad and subjective discretion. Cinergy also argues that the TEMT contains penalty provisions that are too vague and that give too much discretion to the IMM to determine when penalties are appropriate. For example, the definition of the allowance level (over which all real-time purchases would be subject to a penalty) contains little substantive guidance. The Midwest ISO's tariff should specify the procedure to be used, and factors to be considered, in determining this level.

352. The Midwest ISO TOs say that the provision for load-serving entities that have been using the Real-Time Market too much to be required to purchase or schedule all of their expected power requirements in the Day-Ahead Market requires clarification. A load-serving entity with its own generation or GFAs should be allowed to use those resources as well and should not be required to obtain all its supplies in the Day-Ahead Market.

353. The Midwest ISO TOs and Cinergy state that penalties can only be imposed by the Commission, not by the IMM. Cinergy believes that the Commission should review and address conduct of market participants under its responsibility to enforce the FPA and pursuant to the dictates of administrative due process. It argues that allowing a private non-governmental entity to exercise adjudicatory penalty authority would constitute an improper delegation of Commission jurisdiction under sections 205 and 206 of the FPA. Cinergy wants the tariff revised to require the IMM to refer recommended penalties to the Commission for investigation. Given the severity of the penalties and the discretion of the IMM, FirstEnergy believes the Commission should require the Midwest ISO to justify its penalty actions in a section 206 process before the mitigation would apply. AMP-Ohio asks for a modification of Section 65.3.4 to specify the tariff schedule against which penalty amounts should be credited.

#### c) Discussion

354. Penalty charges are imposed upon market power abuses that cannot be dealt with prospectively, such as physical withholding that can only be identified *ex post* through investigations and/or audits. In cases dealing with physical withholding, uneconomic production, or deviations from "Good Utility Practices," it appears that evaluation of the conduct would involve subjective judgments. The Commission's Market Behavior Rules establish that this type of inquiry is to be conducted by the Commission, not by the market monitor. Recent Commission decisions have authorized market monitors to enforce certain ISO and RTO tariff matters if those matters: (1) are expressly set forth in the tariff; (2) involve objectively-identifiable behavior; and (3) do not subject the seller to sanctions or other consequences other than those expressly approved by the Commission and set forth in the tariff.[220] The Midwest ISO's proposal does not meet these

[220] *See* Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 105 FERC 61,218, *clarified*, 105 FERC ¶ 61,277 (2003), *order on reh'g*, 107 FERC ¶ 61,175 (2004). *See also* California Independent System Operator Corporation, 106 FERC ¶ 61,179 (2003), *reh'g denied*, 107 FERC ¶ 61,118 (2004), *reh'g pending* (permitting the California ISO's market monitor to administer certain behavior-related tariff provisions and to charge penalties for certain behavior).

requirements, particularly the requirement that the enforcement relate to objectively identifiable behavior.

355. Investigation of tariff violations and associated enforcement associated with Module D should be conducted by the Commission. As such, we will require that, in the event the IMM identifies potential tariff violations for which penalty charges are provided in the tariff, the IMM shall refer such matters to the Commission.[221] We believe that tariff Section 65.3 is sufficiently detailed to guide the IMM with respect to identification of behaviors that warrant referral. Thus, rather than provide a basis for the IMM and RTO to undertake the imposition of penalty charges, we believe that the Section 65.3 criteria will trigger a referral to the Commission. The Commission will then exercise its judgment as to whether the tariff has been violated and any associated penalty charge may be proper.

356. Further, since all market-based rate sellers in the Midwest ISO's markets are subject to the Commission's Market Behavior Rules, we will require the Midwest ISO to include the Commission's Market Behavior Rule 2, as applicable, in its tariff.[222] As we stated in our order with respect to the California Independent System Operator's proposed tariff Amendment 55 by including such language in an RTO tariff, "we can provide uniformity and clarity for market participants through consistent requirements." Of course, any potential violations of this provision of the tariff identified by the IMM should also be referred to the Commission. By including the language of the Commission's Market Behavior Rule 2 in the Midwest ISO's tariff, we will have further included a strong general anti-manipulation standard which, due to the uniformity of its language, in sellers' tariff's and other ISO tariffs, will help us develop clear rules and interpretations of the standard bringing additional certainty to the market.

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[221] We are sensitive to the fact that since even a referral may cause potential negative effects on a market participant that is ultimately found to not have violated the tariff, such referrals should be made confidentially. We will require the Midwest ISO to provide for such confidential treatment in its tariff.

[222] In exercising its discretion to determine the appropriate remedy for violations of Market Behavior Rule 2, as added to the Midwest ISO's tariff, the Commission will apply the policies and principles set forth in Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 105 FERC 61,218, *clarified*, 105 FERC ¶ 61,277 (2003), *order on reh'g*, 107 FERC ¶ 61,175 (2004), and subsequent relevant precedent.

357. Finally, since the Commission will be making all determinations with respect to penalty charges hereunder,[223] we believe the determination of the penalty charges can be revised to provide the Commission the ability to exercise its judgment on the matter at hand. Thus, the Midwest ISO shall revise Section 65 to provide for penalty charges "up to" the amounts set forth therein.

358. We also order that until the TEMT establishes clear, objectively quantifiable standards for what constitutes an improper bidding balance between the Day Ahead and Real Time Market, it may not establish limitations (such as how much can be bid in each market) on such behavior. In addition, the TEMT must establish clear, objectively identifiable standards for what the limitations will be before it can impose such limitations.

359. Penalties must be designed to be a clear deterrent to unwanted behavior without being so high as to be unnecessarily punitive.[224] Here, the TEMT establishes the same base penalty amount and a similar multiplier structure that we approved for NYISO.[225] Thus, we approve the proposed level of penalties but urge the IMM to watch closely to see if the penalty levels appear appropriate, and to ask the Commission to order, pursuant to section 206 of the FPA, changes if they are not.

360. In response to the Midwest ISO TOs concerns, clearly a party with bilateral contracts should not be required to obtain those same volumes in the Day-Ahead Market. However, having it schedule those contracts in the Day-Ahead Market is entirely appropriate.

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[223] In light of our determination earlier that we will not allow the proposed "temporary Mitigation Measures," we will also reject Section 67 as no longer needed, as Section 67 essentially provides an appeals process when such measures are imposed.

[224] Order No. 636-A explained that the purpose of penalties is to inhibit abusive behavior, and so penalties need not be cost-based. *See* Pipeline Service Obligations, *et al.*, Order No. 636-A, FERC Stats & Regs. ¶ 30,950 at 30,584, *order on reh'g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992), *reh'g denied*, 62 FERC ¶ 61,007 (1993), *remanded on other grounds*, 88 F.3d 1105 (D.C. Cir. 1996).

[225] *See* NYISO FERC Electric Tariff, Attachment H, Fifth Revised Sheet No. 475, Sections 4.3.3 and 4.3.4.

361. We agree with AMP-Ohio that the TEMT needs to be modified to specify the tariff schedule under which the penalty revenues will be refunded. We will require the Midwest ISO in the compliance filing to amend its tariff to specify the tariff schedule under which penalty revenues will be refunded.

362. Section 65.4.3.c states that "The Allowance Level and the Penalty Level shall be established at levels deemed effective and appropriate to mitigate the market effects described in this Section 64.4." However, there is no Section 64.4 in the tariff. The Midwest ISO is directed to correct the tariff to provide the appropriate cite.

### 11. Reporting

#### a) The Midwest ISO's Proposal

363. The TEMT establishes that the IMM will provide annual reports to the Midwest ISO and its Board of Directors, to the Commission and to state regulatory commissions. These reports will provide relevant market data and the results of analyses of the data undertaken by the IMM. It will also provide the results from preliminary investigations to interested government agencies.

#### b) Protests and Comments

364. WEPCO states that the TEMT should be revised so that the IMM will also report its findings to the CEO of the Market Participant, similar to NERC procedures. OMS wants the Midwest ISO to modify Sections 52.3.a.i, 52.3.b, and 56.2 of the TEMT such that affected state regulatory commissions get IMM reports, are notified immediately in the event that the IMM identifies a significant market problem, and receive IMM analyses requested by market participants.

365. Other parties are concerned about the contents of the reports. ELCON states that the proposal to integrate demand response resources into the Day-Ahead and Real-Time Markets should be evaluated on a regular basis by the IMM, to show that the uniform price format of the bid-based markets will result in a lower revenue requirement than would otherwise result from cost-of-service regulation. AMP-Ohio requests that the Commission require the Midwest ISO and the IMM to track and report on at least an annual basis any mitigation costs (number of megawatts and dollars) resulting from improper mitigation. This information could be included in the annual state of the market report.

#### c) Discussion

366. We agree with WEPCO that the TEMT should be modified such that the CEO of a Market Participant will be notified about IMM findings directly relating to his or her company. We also believe that state regulatory commissions should get copies of IMM reports and the market participants' requested analyses conducted by the IMM.

367. While we agree with ELCON and AMP-Ohio that information they request would be useful in the annual reports by the IMM, we understand that the IMM's resources may be limited and we leave it to the IMM to decide if it wants to include that information.

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

### 1. System Supply Resources

#### a) The Midwest ISO's Proposal

368. To assure reliable grid operation, the Midwest ISO proposes to implement a System Supply Resource (SSR) Program that will allow it to negotiate compensation for selected units that are uneconomic but needed for reliability reasons. Market participants must submit an affidavit at least 26 weeks in advance of any plan to retire, place into extended reserve shutdown, or disconnect a generation unit. Based on information submitted by the Market Participant, the Midwest ISO will determine if the unit should be designated an SSR. The Midwest ISO will enter into agreements with SSR units to allow for recovery of certain going-forward costs, offset by expected payments for resource adequacy and revenues from energy market transactions. The agreements will be filed with the Commission, but the Midwest ISO's proposal does not specifically require that the Commission approve the negotiated agreements. SSR costs will be assigned on a *pro rata* basis to the market participants serving load in the affected control areas. The Midwest ISO anticipates that SSR units, whose status will be reviewed annually, will be used primarily for reactive power.

#### b) Protests and Comments

369. Comments on the SSR Program as proposed by the Midwest ISO were generally negative. OMS, for example, believes that reliability issues should be dealt with comprehensively and that until resource adequacy requirements are established, defining a role for SSR is premature, especially since reliability is traditionally the responsibility of utilities. Cinergy opposes the program because it is mandatory and expresses concern that the proposal will not provide full compensation for costs. FirstEnergy opposes the program because the determination of SSR units relies on unexamined claims by generators that they are uneconomic. Furthermore, it objects to allocating SSR costs to entities that have procured sufficient resources to meet the reliability needs of their loads.

Detroit Edison objects to the plan because it is unnecessarily burdensome and fails to specify compensation clearly. Midwest TDUs state that SSR costs should be allocated on cost-causation principles, and such an analysis should be part of the SSR study.

### c) Discussion

370. We find that the SSR program is a reasonable backstop measure to assure reliability in the markets to be operated by the Midwest ISO. The Midwest ISO proposes the SSR program to address the concern that reliability could be compromised by the exit of uneconomic resources. The SSR program would impede competitive exit for a limited period when exit would jeopardize reliability, and it provides general guidelines for compensating SSR units.

371. Although an efficient market design should provide adequate cost recovery for all units needed for reliability, experience in the eastern markets with similar market designs has revealed occasional cost recovery problems for generators that run primarily for reliability. These generators fail to recover sufficient costs from participating in competitive wholesale markets for energy and operating reserves. Furthermore, when these generators are needed, they often confront market power and mitigation rules that prevent them from charging high enough rates to recover costs. Resource adequacy requirements satisfied through various mechanisms, such as capacity markets (sometimes enhanced with a downward-sloping demand for reserves), may provide an additional source of revenue for these generators. Nevertheless, these markets have developed, or are considering, backstop mechanisms that allow them to prohibit exit on a limited basis in the event exit would jeopardize system reliability. The SSR program would fulfill a similar role for the Midwest ISO where issues of generator cost recovery are likely to be more limited. This is because many generators in the region, at least at this time, do not rely on wholesale revenues for cost recovery. Instead, their costs are recovered either as part of retail rate base or from long-term bilateral contracts. Thus, in our view, the SSR proposal is a reasonable reliability assurance measure consistent with our recently-enunciated policy on reliability compensation issues.[226]

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[226] *See* PJM Interconnection, L.L.C., 107 FERC ¶ 61,112 (2004), *reh'g pending*. The policy first requires that a distinction be drawn between short-term and long-term reliability issues. It describes short-term reliability issues as those that relate to generators that are needed for reliability but subject to mitigation, and that as a result receive non-compensatory revenue. Long-term reliability issues are local capacity shortages identified in the planning process that may result from either expected retirements or the need for new infrastructure. The Commission favors market design remedies, where possible, to provide needed revenues to support reliability-based

(continued)

372. We accept the Midwest ISO's negotiated approach to determining SSR costs. Accordingly, because the tariff contains no rate mechanism, we will require the Midwest ISO to file under section 205 of the FPA for cost recovery at the time it seeks to charge customers for SSR costs. We also accept that costs will be allocated to market participants serving load in the affected control areas, even though we agree with the observation that under this approach, some entities that have satisfied capacity requirements may nevertheless be required to pay for SSR costs. Currently, procuring sufficient resources to meet reliability needs of individual loads does not guarantee sufficient reactive power, a major motivation for the SSR program. The Midwest ISO's SSR program is a prudent measure for protecting reliability, especially since inadequate reactive power was one of the contributing factors to the August 14, 2003, blackout.[227] We agree that SSR costs are appropriately assigned to market participants serving load in the affected control areas.

### 2. Demand Response Resources

#### a) The Midwest ISO's Proposal

373. According to the Midwest ISO, demand response resources (DRRs) are loads that can respond to dispatch instructions in real time or to high prices in the Day-Ahead Market. Section 38.2.2.g of the TEMT specifies that DRRs will be allowed to participate in the markets in a manner comparable to generation resources, provided that they comply with requirements necessary for the Midwest ISO to validate their ability to respond as intended. A DRR must specify prices at which it will voluntarily adjust its day-ahead schedule; it may specify a minimum charge for initiating curtailment, regardless of the quantity or duration, and a minimum hourly charge for the lowest megawatt level of curtailment. Comparable to generation resources, the TEMT indicates that DRRs will be scheduled and dispatched when they are economic.

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generators and other needed investments. Capacity markets, location-specific operating reserve requirements, and scarcity pricing are market design measures that support these objectives. The policy recognizes that market design measures may not always prove effective; thus, the Commission is willing to consider specific proposals as a last resort, provided that the proposal: (1) has a clear triggering event; (2) explains why market design options are not appropriate; and (3) assigns costs to beneficiaries. One possible short-term remedy is a generator-specific contract with the RTO or ISO.

[227] *See* Final Blackout Report at 18.

374. The Midwest ISO describes its DRR program as an added tool for alleviating congestion and enhancing reliability. Its implementation would allow the Midwest ISO to better balance supply and demand without resorting to involuntary curtailments or other non-market actions. However, according to filed testimony, potential difficulties with the DRR program have not been fully resolved.[228] In particular, the Midwest ISO notes that it is impossible to determine whether DRRs are reducing their load in response to their offer or other factors, and it proposes to resolve outstanding issues possibly with metering or Business Practice Rules. In the meantime, DRRs would not be fully comparable to Generation Resources. In particular, a revenue sufficiency guarantee paid to generators that provide emergency energy would not be paid to DRRs; penalties for uninstructed deviations and the $1,000 bid cap would not apply to DRRs. Thus, in a shortage situation, a DRR offer could set LMP above $1,000 per megawatt-hour. However, a bid that exceeds the $1,000 safety-net cap would require price verification.

### b) Protests and Comments

375. Parties generally support the Midwest ISO's plan to integrate demand response into its market design. However, LG&E would reject the DRR plan unless non-retail access states, such as Kentucky, would have the ability to prohibit participation of resources in their states if participation is inconsistent with the laws and regulations of the state. Others, such as ELCON/AISI/ACC and the Steel Producers, would expand participation of DRRs ─ explicitly include them in the RAC process and allow them to serve as capacity resources ─ and compensate them the same as generation resources. Southwestern would subject DRRs to the $1,000 per megawatt hour safety-net bid cap.

### c) Discussion

376. The Commission supports the use of demand response programs as a means to enhance reliability and as a mechanism to give developing markets experience with the potential of demand to react to prices to support reliability. In that context, we have previously approved various demand response programs for PJM, CAISO, NYISO, and ISO-NE. In these markets, demand response resources can both bid their reductions into the Day-Ahead Market and serve as emergency resources. These programs have been operated during periods of high prices and emergency conditions. LG&E does not explain how the DRR program proposed by the Midwest ISO could run afoul of state laws in states that have not adopted retail access. Thus, absent a specific concern, we decline to grant the clarification LG&E requests.\

[228] *See* McNamara testimony at 70-71.

377. The Commission generally agrees with the goals and overall framework of the proposed DRR program. However, a number of features require further explanation and/or clarification. First, Section 39.2.10.b refers to DRRs that are available only in Maximum Generation Emergencies, yet it does not define how such resources are identified. Experience with emergency demand response programs in other markets suggests that some DRRs may be unwilling to provide offers for various schedule reductions, but would nevertheless be willing to curtail if called upon under emergency conditions. The Midwest ISO tariff does not appear to accommodate such a role for DRRs, but we will require the Midwest ISO to create such a role, as described further in our review of the proposed Emergency Procedures. Second, the Midwest ISO must explain what price verification of DRR offers above the $1,000 safety-net level would entail.[229] Third, although the tariff indicates that load may qualify as a DRR only if it complies with requirements necessary for the Midwest ISO to validate its ability to respond as intended, filed testimony suggests that this matter has not been resolved.[230] The Midwest ISO must provide further detail on how it intends to measure the response of DRRs and what actions it would take for non-compliance. Also, it must explain how DRR measurement concerns are properly addressed by not paying DRRs a revenue sufficiency guarantee, not subjecting them to penalties for uninstructed deviations or the $1,000 bid cap that applies to generation resources. Finally, the Midwest ISO must explain why DRRs should not: (1) participate in the RAC process; (2) serve as a capacity resource; or (3) provide operating reserves.

### 3. Offer Caps

#### a) The Midwest ISO's Proposal

378. The Midwest ISO proposes to adopt a $1,000 per megawatt-hour bid cap comparable to the caps that apply in the PJM, NYISO and ISO-NE markets. It chooses this value as reasonable to provide price stability for the interim period while a long term resource adequacy program is being developed.

#### b) Protests and Comments

379. Few parties commented on the proposed $1,000 bid cap. Cinergy and Detroit Edison believe any cap is inconsistent with market goals, although Cinergy could accept a $5,000 cap as a transition measure. FirstEnergy and PSEG object to the cap because

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[229] *See* Module C, section 40.2.3.b.ix, Original Sheet No. 550.

[230] *See* McNamara testimony at 70-71.

the Midwest ISO has offered no convincing support for choosing $1,000 per megawatt-hour. Dynegy objects to the Midwest ISO's decision to reduce the bid cap from $5,000 per megawatt-hour (as previously accepted in a stakeholder vote) to $1,000 per megawatt-hour with no justification that the reduced value will provide adequate compensation during scarcity conditions. It also points to the fact that DRRs are not similarly bound by the $1,000 bid cap.

#### c) Discussion

380. We accept the Midwest ISO's proposal to adopt a $1,000 per megawatt-hour bid cap, as a means to maintain price stability during the transition period before a comprehensive and permanent resource adequacy plan has been implemented. The decision to establish a safety-net bid cap, at any level, is unavoidably controversial because the choice is a pragmatic one that sets an initial limit on generation offers independent of actual costs. The $1,000 per megawatt-hour bid caps that apply in PJM, NYISO and ISO-NE similarly are not based on specific generator operating or opportunity costs.

381. We agree with those who argue that safety-net bid caps ultimately should not be part of a well-designed market. In typical markets, price is disciplined by the demand side's willingness to pay. The safety-net cap can be regarded as a proxy for demand bids. In our judgment, the potential for unanticipated price volatility at the startup of a new market in which there is no history of pooled operations strongly argues for such a safety measure. Furthermore, our experience to date with the $1,000 bid cap in other markets does not suggest that the cap is responsible for cost recovery problems or creates a major impediment to investment. As noted previously, we will require further explanation for the lack of symmetry between generation and demand response resources, and we will continue to evaluate the Energy Markets to determine whether adjustments are warranted.

### 4. Emergency Procedures

#### a) The Midwest ISO's Proposal

382. Shortage conditions, defined as Maximum Generation Emergency conditions, trigger emergency procedures in both the Day-Ahead and the Real-Time Markets. A shortage in the Day-Ahead Market occurs when the sum of demand bids (including price-sensitive demand),[231] exports, and virtual bids cannot be satisfied with all available offers

[231] Price-sensitive demand results when load-serving entities are allowed to indicate how they will limit consumption as LMPs rise (*i.e.*, their demands are downward-sloping).

from generation, imports, and virtual supply, *i.e.*, the market cannot be cleared with existing bids and offers. A shortage in the Real-Time Market occurs when the real-time demand forecast cannot be satisfied with all available generation, self-schedules, and DRR offers.

383. A shortage condition in either market allows the Midwest ISO to consider additional supply sources (*e.g.*, offers from the emergency range of generation resources, DRRs available only for maximum generation emergencies, and emergency energy purchases) that are only available in these emergency conditions. It also may trigger a shortage pricing mechanism which administratively establishes the highest accepted offer at the $1,000 per megawatt-hour safety-net level. Emergency procedures are defined by similar sequential procedures followed in the Day-Ahead and Real-Time Markets in shortage conditions.

384. First, to clear a day-ahead shortage, supplies that can be provided from the high emergency range of on-line generation resources and DRRs will be scheduled, and their offer prices will be used to calculate LMPs. If the first step is not sufficient to balance the market, offers from off-line generation and DRRs available only for Maximum Generation Emergency conditions will be used to calculate LMPs. Third, as a final measure, shortage pricing may be triggered if the first two steps do not resolve the shortage. The Midwest ISO will proportionately reduce bids to achieve a supply/demand balance and offers will be set at the highest offer of all on-line generation or $1,000 per megawatt-hour, whichever is greater.

385. The Midwest ISO proposes a similar sequence of steps to deal with shortages in the Real-Time Market. First, supplies from the high emergency range of all on-line resources will be dispatched and used to calculate LMPs. Second, operating reserves may be used to provide energy which would trigger the shortage pricing mechanism. In this case, segments of reserve capacity dispatched in merit would be offered at $1,000 per megawatt-hour and would be used to set LMPs. Third, before resorting to load shedding, off-line generation available only for Maximum Generation Emergency conditions would be used to clear the market. Apart from these steps, the Midwest ISO may also make emergency energy purchases following a notification. In response to the notification, market participants and neighboring control area operators may submit offers for emergency energy which will be accepted on an economic basis. Emergency purchases, however, will not be used to determine LMPs.

#### b) Protests and Comments

386. Parties did not comment on the emergency procedures.

#### c) Discussion

387. The Commission accepts the proposed Emergency Procedures subject to the following modifications. First, generation resources are required to specify supplies and corresponding offers available from an emergency range outside the economic minimum and maximum levels. Supplies from the emergency range for any resource may only be scheduled or dispatched after all available economic supplies, including DRRs, have been exhausted. However, offers from the emergency range of some resources could be less than offers from the economic range of other resources. The Midwest ISO must modify the TEMT to assure that the least-cost option, whether economic or emergency, is scheduled or dispatched. Second, the Midwest ISO must integrate notification and emergency purchases, in contrast to purchases from the emergency range, into the sequence of steps used to resolve real-time shortages. Third, the Midwest ISO must exclude market participants from making separate offers for emergency purchases to the extent each is already providing offers for supplies outside the economic minimum and maximum range. Fourth, the Midwest ISO must specify in the TEMT the information DRRs are required to provide to support bids above the $1,000 bid cap applicable to generation resources. Finally, in light of the importance DRRs provide in emergency situations in eastern markets, we will require the Midwest ISO to modify the TEMT to allow such resources to respond on an emergency basis only, in addition to participating by bidding into the markets, as we noted in our DRR discussion.

## *H. Resource Adequacy Requirements*

### 1. General Proposal

#### a) The Midwest ISO's Proposal

388. The Midwest ISO proposes an interim resource adequacy plan in Module E of the TEMT. In addition to the Module E tariff language, the Midwest ISO filed three supporting exhibits as attachments to its transmittal letter: (1) OMS "Principles of Resource Adequacy and Capacity Markets," which provides guidelines for the Midwest ISO to consider while developing a region-wide resource adequacy requirement; (2) a joint Midwest ISO Supply Adequacy Working Group/OMS Resource Adequacy Working Group (SAWG/RAWG) "Work-Plan" that breaks the task of developing a permanent resource adequacy plan into four phases; and (3) a Gantt chart that outlines the tasks within the phases and an estimate of the time required to complete the objectives of the Work-Plan.

389. The interim Resource Adequacy Requirements (RAR) are based on the current reliability mechanisms of the states and the Regional Reliability Organizations (RROs) within the Midwest ISO. Market participants must comply with the appropriate state or regional reliability requirements where their load is served. There is no compliance obligation for the *pro rata* share of load that is outside the Midwest ISO. If load is located in multiple regions within the Midwest ISO, it will be pro-rationed according to each area's reliability requirements. The Midwest ISO will determine what standards are in place in each state or region and then notify market participants of their applicable obligation where the load is served. In the event of a conflict between state and RRO reliability requirements, market participants will fully comply with the state's requirements and then the portion of the RRO requirements that is feasible. If the Midwest ISO does not find any reliability standards in place where load is being served within its region, it proposes to institute a default annual reserve margin of 12 percent.

### b) Protests and Comments

390. Numerous intervenors filed comments and protests regarding the Midwest ISO proposal to adopt an interim RAR plan. General comments were that Module E lacks sufficient detail to determine what standards will apply, when standards are in effect, who makes these determinations, and what the consequences of non-compliance are. Other intervenors urge the Commission to reject portions or all of Module E so that stakeholder and Midwest ISO resources can be focused on developing a permanent plan. Many intervenors emphasize that a permanent plan must be in effect prior to the start of Day 2 market operations or as soon thereafter as practicable. Finally, there were many comments that should the Commission accept the proposal to adopt an interim RAR plan, it should then order the Midwest ISO to modify the interim proposal.

391. The amount of detail in Module E brought many intervenors to comment on the interim RAR plan. According to the Ohio Commission, the interim resource adequacy plan needs modification because it contains insufficient details, it does not communicate market participants' responsibilities, and it creates confusion about the criteria it does contain. To alleviate these concerns, the Ohio Commission recommends interim revisions, before an operational capacity market is in place, that include: (1) development of a Network Resource nomination process with options similar to those proposed for GFAs; (2) a mechanism to attract sufficient capacity into a pool of unforced capacity units; (3) a cost-based funding mechanism to ensure participation in the pool; and (4) a sunset provision to transition from this cost-based system to a market-driven one. AMP-Ohio and Dynegy comment that Module E does not contain enough detail to be workable. In sections it refers to the Business Practices Manuals, which AMP-Ohio and Dynegy state are incomplete and still under discussion; they therefore argue that the Midwest ISO should either provide more detail or remove Module E from the TEMT.

392. Many comments did not protest the interim plan; instead, they sought requirements that focus on permanent RAR development after the interim measures expire. In that regard, Dominion requests a Commission directive for the Midwest ISO to submit a compliance filing that outlines its plans to establish permanent RAR requirements. Dominion contends that the plan should follow those that are already established in the other ISOs, and be in effect prior to the start of Day 2 markets or no later than April 1, 2005. Duke requests that the Midwest ISO provide periodic status reports to the Commission that outline how a permanent RAR plan will be implemented by June 30, 2005. EPSA and PSEG urge the Commission to establish milestones to monitor progress toward a permanent RAR plan, and a sunset date for the interim plan. Reliant suggests a sunset date of December 31, 2005. Wisconsin Retail Customers Group and WPS Resources ask the Commission to delay the Midwest ISO market start without a filed, stakeholder-approved, final RAR plan in place.

393. Numerous intervenors filed comments to support the interim RAR provisions in Module E. Coalition MTC supports the interim resource adequacy proposal in Module E. They believe it reflects a reasonable compromise due to the inability of the stakeholder groups to reach a consensus prior to the tariff filing. IMEA support the Alternative Capacity Resource (ACR) provisions in Section 70, and suggests that behind-the-meter generation should be included in the permanent RAR plan with a separate item for it in the "Resource Adequacy and Capacity Markets Principles." Municipal Participants also support the ACR section as a permanent feature of any resource adequacy plan. However, AMP-Ohio argues that the proposal to use behind-the-meter generation and interruptible demand as ACRs, while a good start, does not fully meet the municipals' needs. Strategic supports the Module E language, but emphasizes the necessity of accommodating retail choice states and allowing a grace period for load-serving entities to comply with the requirements. OMS generally supports the concept of an interim RAR plan while the joint SAWG/RAWG stakeholder groups develop a permanent RAR plan for the Midwest ISO region. However, OMS found the present Module E to lack sufficient details and it proposes that the Commission direct further clarifications in the following areas: seams, the must-offer requirement, non-compliance and penalties, long-term system requirements, demand forecasts, and resource qualification.

394. In response, the Midwest ISO states that it continues to believe that the interim RAR established through Module E are necessary and appropriate as an integral component of the Midwest ISO market. It notes that although it would prefer stakeholder consensus on the resource adequacy provisions, it has a responsibility to ensure that adequate resources are available to meet load during the transition phase; therefore, an interim plan was needed until a formalized plan may be submitted for Commission approval. The Midwest ISO notes that the ongoing RAWG SAWG stakeholder process

is the appropriate venue in which to develop changes to Module E. The Midwest ISO pledges to continue to coordinate closely with OMS and stakeholders on resource adequacy issues.

395. In addition, the Midwest ISO gave specific responses to some of the requirements that received the most comments. It acknowledges that although Module E was meant to rely on existing standards and programs, it may represent changes, especially regarding reporting requirements, for entities in states with retail choice programs. The Midwest ISO states that to ensure comparable treatment for all loads, the requirement to identify which resources market participants intend to rely upon to meet applicable standards will apply to the Market Participant serving load in all areas of the Midwest ISO region. In response to comments on the must-offer and Designated Network Resource (DNR) provisions, the Midwest ISO states that it continues to believe that such requirements are necessary to ensure that resources are available to serve load during times when reliability may be threatened. However, the Midwest ISO notes that the DNR is a new requirement that will initially be applied flexibly, with a possible grace period for all market participants to comply.

### c) Discussion

396. We are encouraged that the Midwest ISO is committed to developing and adopting a permanent resource adequacy plan through the stakeholder process. We intend to rule on the necessary aspects of the interim proposal contained in Module E to ensure that it does not compromise reliability and market readiness, but instead provides a framework for future stakeholder discussions culminating in the filing of a permanent plan within a reasonable time period. We view Module E as a transition mechanism to bridge the gap between market startup and the implementation of a permanent RAR plan. In that regard, we establish the time parameters and directives below.

397. Resource adequacy is a crucial component of the Energy Markets that can help to ensure new resource development, market efficiency, and reliable operation of the transmission network. We acknowledge that the details of an effective RAR plan may vary by region, and as such, we will require permanent resource adequacy requirements that consider the unique characteristics of a market's participants, the region's needs, and the views of applicable states.[232] Accordingly, 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. We also expect that any permanent resource adequacy plan will provide a consistent platform to support the

[232] In this case, the appropriate states to consider would most likely be represented by OMS.

region's short-term reliability needs and encourage long-term planning and investment in infrastructure. Given the significant overlap of the Midwest ISO and PJM markets, we strongly encourage parties in both areas to seek a common Installed Capacity design. We note that PJM is in the process of redesigning parts of its Installed Capacity market.

398. We agree with some of the intervenors' comments that certain areas in Module E lack sufficient detail and clarity. We therefore direct the Midwest ISO to file specific modifications and clarifications as discussed herein.

### 2. Network Resources

#### a) The Midwest ISO's Proposal

399. Market participants must identify to the Midwest ISO, on at least an annual basis, the resources they are relying on to comply with their resource adequacy standards for operating and planning reserves. Resources that market participants identify as available to satisfy reliability requirements must be qualified based on criteria that the Midwest ISO will develop in conjunction with the OMS, state regulators, and RROs. The Midwest ISO will review compliance with state and RRO reliability requirements on at least an annual basis. Qualified generating resources available to satisfy RAR are designated as Network Resources.

400. Owners of Network Resources are required to demonstrate that the resource is able to serve load within the Midwest ISO. Market participants are required to own the resources or contract with another party for the use of their resource to comply with the Network Resources requirements. To ensure deliverability, Module E requires a request for Network Integration Transmission Service for new Network Resources.

401. Deliverability will be validated through System Impact Studies that consider the delivery of aggregate resources of Network Customers to the aggregate of Network Load. The Midwest ISO proposes to retain the discretion to allow a grace period for full compliance with the Network Resource requirements.

402. Alternative Capacity Resources (ACR) are resources that may not qualify as Network Resources, but nonetheless may satisfy the criteria to count toward the state or RRO resource adequacy standards. The Midwest ISO has proposed two types of ACRs, interruptible demand and behind-the-meter generation.

#### b) Protests and Comments

403. The Midwest TDUs argue that the requirement for "ownership or equivalent contractual rights" to designate a network resource is unreasonable. Instead they argue that Module E should rely solely on the definition for Network Resources given in Section 1.217. Detroit Edison requests Commission clarification that interruptible power

contracts may not qualify as DNRs. AMP-Ohio argues that Section 69 should provide more details about which resources can satisfy the DNR requirements because it confuses point-to-point and network resources and they argue a point-to-point customer's supply sources should not be designated as network resources. AMP-Ohio argues that a grace period for full compliance with DNR requirements in Section 69.1.3 should not be subject to the Midwest ISO's discretion. It suggests that the Commission order a minimum six-month grace period for compliance with the DNR requirements. In contrast, Dynegy urges the Commission to reject the grace period due to the possibility of selective enforcement at the Midwest ISO's discretion. Consumers propose an additional exemption to DNR requirements for energy-limited resources, such as hydro or fuel-limited resources.

### c) Discussion

404. We will require the Midwest ISO to flexibly apply the DNR requirements initially and its recognition of the need to allow time for a transition period. If the Midwest ISO determines that a grace period for compliance is necessary; then we direct that any grace period given must apply to all affected market participants equally. However, we agree with intervenors that it is not clear which resources may qualify as Network Resources. As the Midwest TDUs note, Section 1.217 of the TEMT already contains a definition of Network Resources. Therefore, we will require the consistent use of the Section 1.217 definition for the interim RAR proposal. We further direct the Midwest ISO to file additional details about the specific resources that qualify to satisfy the DNR requirements.

405. We direct the Midwest ISO to revise Original Sheet No. 819, Section 69.1, titled Designation of Network Resources. As written, the first sentence reads, "Resources identified by market participants as available to meet the reliability requirement determined by the Transmission Provider must comply with the requirements for designation of designated Network Resources consistent with the procedures set forth by the Transmission Provider." We direct the Midwest ISO to make this sentence grammatically correct by deleting the word "designated" before the word "Network" and by making "Resources" singular. As revised, the sentence should read, "Resources identified by market participants as available to meet the reliability requirements determined by the Transmission Provider must comply with the requirements for designation of a Network Resource, consistent with the procedures set forth by the Transmission Provider."

### 3. The Must-Offer Requirement

#### a) The Midwest ISO's Proposal

406. The Midwest ISO proposes a "must-offer" requirement under which Designated Network Resources (DNRs) must submit a self-schedule or offer in the Day-Ahead Market and the first RAC process, unless the resources are unavailable due to an outage. Must-offer requirements are further specified in the Business Practices Manuals and are intended to reflect the operational limitations of affected resources.

#### b) Protests and Comments

407. Many protests and comments on the must-offer requirement in Section 69.2 request more details, modifications, or removal of the entire Section. PSEG argues that without a means to compensate Network Resources through a capacity payment or a way to enforce the default 12 percent reserve margin, the Commission should require the Midwest ISO to remove the must-offer obligation. AMP-Ohio, the Midwest TDUs, and Dynegy protest the must-offer requirement due to a lack of details about compliance, enforcement, dynamic scheduling, and compensation. Cinergy asserts that the must-offer requirement in Module E confuses planning reserves RAR and operating reserves because the capacity resource requirements contained in Section 68 are determined on an annual or a six-month basis while the must-offer requirement is used to ensure sufficient operating reserves on a day-to-day basis. According to Cinergy, the must-offer requirement should only apply to the RAC process after the Day-Ahead Market because only the RAC addresses the potential gap between commitments in the Day-Ahead Market and the generation needed to meet forecasted load. Detroit Edison states that the must-offer should be limited to day-ahead load projections plus reserve margins.

408. LG&E recommends that the Commission reject Section 69.2, or condition its approval on an "opt-out" provision for generation owned by utilities with a state-imposed obligation to serve. LG&E requests a similar opt-out provision for the Alternative Capacity Resources in Section 70. Finally, LG&E argues that the resource adequacy Sections of the tariff violate FPA section 201(b)(1) and therefore the Commission should reject the RAR language or provide an opt-out provision for all of Module E. In lieu of Module E, LG&E recommends an alternative two-pronged proposal that consists of an energy cap set at $5,000/MWh and procedures so that when the Midwest ISO experiences a generation deficiency within its reliability area, a load-serving entity can demonstrate in a set time frame that it is resource-adequate.

#### c) Discussion

409. In eastern ISOs, the obligation to bid into the day-ahead market has been

associated with the supply of a resource adequacy product.[233] In the markets that the Midwest ISO proposes, load-serving entities are required to identify suppliers that qualify to meet their resource adequacy obligation. The capacity obligation on load-serving entities in the Midwest ISO will be the identification of sufficient DNRs. Those DNRs will subsequently have a day-ahead must-offer requirement. We have concerns with the details of the must-offer requirement for DNRs without a corresponding capacity payment. If not applied properly, the program may allow load-serving entities that have not procured adequate resources to unfairly lean on the resources of other load-serving entities. Ultimately, this may lead to inadequate infrastructure development incentives. However, we will not require in this order a separate capacity product or payment to DNRs to obligate participation in the Day-Ahead Market for this initial interim plan.

410. We note that the states and RROs currently have mechanisms in place to ensure fixed-cost recovery for network resources. Current DNRs are not divested and are therefore in the rate base and thus receiving fixed cost payments. If a load-serving entity does not presently have sufficient DNRs to meet the applicable requirements, then it may contract bilaterally with a generator to become a DNR.[234] The load-serving entity and the generator may determine the appropriate payment structure for the obligation of being a DNR and thus the resource may receive an implicit capacity payment under the current Midwest ISO proposal.

411. We recognize that this is an interim measure only, to be replaced upon the completion of a permanent plan that has been fully vetted through the stakeholder process and filed with the Commission. Therefore, as a temporary measure only, we will allow the Midwest ISO to require that DNRs must offer in the Day-Ahead Market and the first RAC process to ensure that the Midwest ISO has sufficient resources available to maintain the reliability of the system.[235] We direct that the interim tariff sheets will sunset upon Commission approval of a permanent RAR plan that includes an Installed Capacity component. Those resources not identified by a load-serving entity as a DNR will not have these obligations. Major components of RAR, such as the details of the Installed Capacity plan, should be given the opportunity to develop in the stakeholder process before the Commission rules on their merits.

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[233] *See* PJM Reliability Assurance Agreement, Article 7, Second Revised Sheet Nos. 23-26.

[234] Module E, Section 69.1.2(a), Original Sheet No. 820.

[235] We note that DNRs are identified by the load-serving entities, not by the Midwest ISO. *See* Module E, Section 69.1, Original Sheet No. 819.

412. Finally, we note that LG&E, among others, has jurisdictional concerns with the must-offer requirement in Section 69.2. LG&E's concern is that the must-offer requirement could restrict load-serving entities' access to the low-cost resources they use to serve their native load because excess resources could be subject to the Midwest ISO's use for the market, and the Midwest ISO has not demonstrated that this is consistent with the language in section 201(b)(1) of the FPA. We are not convinced that these jurisdictional concerns warrant a rejection of the must-offer requirement at this time. Under the Midwest ISO proposal, load-serving entities may fully use their DNRs to satisfy their must-offer obligation through self-schedules and therefore can ensure that their DNRs are used to serve their respective customers during the Day-Ahead Market and scheduling process. A load-serving entity is only required to bid that portion of its DNR into the Day-Ahead Market that is in excess of its own needs. We reiterate that the mechanics of the DNR must-offer are subject to revision as part of an ongoing stakeholder process and will be refiled in the permanent plan. We also note OMS's statement that it is "reassured by the testimony of [the Midwest ISO's] witness Ronald R. McNamara that [Midwest ISO] market mechanisms will not undermine the ability of states and/or utilities to serve their own customers at the lowest cost."[236]

### 4. The 12 Percent Annual Reserve Margin

#### a) The Midwest ISO's Proposal

413. If the Midwest ISO cannot determine that a resource adequacy standard is in place for a load in a state within the Midwest ISO region, an annual reserve margin of 12 percent applies to load in that state. In general, the Midwest ISO will review compliance with the RAR for each state on at least an annual basis.

#### b) Protests and Comments

414. There were numerous requests for more clarity and details on the proposal to institute a default annual reserve margin of 12 percent where the Midwest ISO finds no standard is in effect for a region. FirstEnergy asks whether the margin requirement applies in both on and off-peak hours, what figures are used to calculate the 12 percent, and how the load-serving entity is to count its available capacity. Furthermore, FirstEnergy recommends that the tariff specify a three-year transition period for load-serving entities to convert to the 12 percent default standard. AMP-Ohio questions whether the Midwest ISO or its members will set the peak demand used to calculate the 12 percent annual reserve margin, and if the municipal entities can challenge Midwest ISO's forecast demand. Regarding the annual compliance audit, they are unclear when

[236] OMS at 52.

the forecast is either due or published, what is the timeline for compliance, and what forms need to be prepared and provided to the Midwest ISO. Cinergy argues that it is unclear how load-serving entities will be compensated for maintaining the 12 percent margin. Consumers is unclear how the 12 percent margin will apply in retail open-access states, where the customer base and necessary reserve margins may fluctuate over time. Consumers submits that if a default margin is used, it should apply to both the utility and the retail supplier. Detroit Edison seeks clarity as to how the Midwest ISO will monitor and verify compliance with the 12 percent requirement and whether non-compliance could result in sanctions.

#### c) Discussion

415. Conceptually, we agree with the Midwest ISO on the need for a default requirement where no reserve margin exists. On the surface, a 12 percent default annual reserve margin for a temporary basis does not strike the Commission as an excessive requirement. However, we agree with intervenors that this requirement does not have enough details for proper evaluation. Therefore we direct the Midwest ISO to file additional details on how the reserve margin will be calculated, how available capacity to satisfy the margin will be counted, what are the consequences of non-compliance, and what time period this requirement would be in effect.

### 5. Jurisdictional Issues

#### a) The Midwest ISO's Proposal

416. Module E's stated goal is to ensure adequate generation resources are available to meet demand through reliance on pre-existing reliability mechanisms of the states and Regional Reliability Regions as adapted to the Midwest ISO region. Because some load is located in the Midwest ISO's region and some is not, adaptations are proposed to divide the load accordingly. If load is outside the Midwest ISO region there is no compliance obligation for that portion of the load. Finally, participants that are serving load in the Midwest ISO region that are members of reserve sharing groups are required to get approval from the Midwest ISO before they withdraw from those groups.

#### b) Protests and Comments

417. Many intervenors have concerns about the potential of Module E to alter the jurisdictional lines between states, RROs, and the Midwest ISO, and diminish rights that parties now have. According to Ameren, the authority to establish RARs resides with the states and RROs and the role of the Midwest ISO is to assist in this process. FirstEnergy also argues that the primary responsibility to implement a RAR plan resides with the states, but it adds that the role of the Midwest ISO should be to monitor compliance. On the other hand, Crescent Moon Utilities disagree with the state-by-state determination of resource adequacy; they feel that it could lead to disproportionate burdens among utilities

and would prefer a uniform methodology for determining the RAR. Ameren argues that the Midwest ISO does not have authority to impose the language in Section 68.1.1.d, Compliance with Regional Reliability Requirements, regarding transmission provider approval before withdrawal from reserve sharing groups. MAPP agrees, arguing that the MAPP Restated Agreement provides for the rights and obligations of the Generation Reserve Sharing Pool, and that the Midwest ISO cannot insert itself into this agreement. MAPP also argues that the Midwest ISO's proposal is arbitrary because it lacks standards, terms or conditions that the Midwest ISO would use to evaluate whether to grant approval of withdrawal from a Reserve Sharing Group, while the MAPP Restated Agreement contains such provisions.

418. Ameren has further jurisdictional concerns in Section 68.2.1a, Determination of Compliance by Transmission Provider, because it thinks that this Section could constitute a grant of authority to the Midwest ISO to compel state commissions to resolve inconsistencies between state and Midwest ISO resource adequacy policies. FirstEnergy argues that Section 68.2.1a.iv should allow the state to ask the Midwest ISO to apply the default for planning reserves. AMP-Ohio and Dynegy seek specific changes to Section 68.1.2, to make it conform to the level of specificity in Section 68.1.1, regarding the state requirements where load is served. The Midwest TDUs also comment on Sections 68.1.2.a and .b, suggesting that these Sections should be revised to require that market participants only adhere to "applicable state requirements." AMP-Ohio argues that in Section 68.2, the "Transmission Provider Requirements," it is entitled to know what the Midwest ISO's interpretation of ECAR and the state of Ohio's requirements are, what timeframe market participants have to bring relevant contracts into compliance, and whether requirements will be known prospectively or retroactively.

419. MAPP argues that Module E usurps the authority of state regulatory agencies and regional reliability councils. It argues that NERC is the most appropriate domain in which to establish operating and planning reserves. Also they argue that Module E contains redundant procedures to identify network resources because such standards are already in place within the MAPP region. MAPP requests that the Commission reject Module E and encourage the SAWG and the RAWG to continue their joint efforts to develop a permanent resource adequacy plan. Manitoba Hydro supports MAPP's comments on Module E, and independently asks for a Commission directive that the Midwest ISO should delete Module E in its entirety because it abrogates long-standing capacity contracts from MAPP members within the Midwest ISO to MAPP members outside the Midwest ISO. MidAmerican and Montana-Dakota support the MAPP comments and further urge the Commission to reject Module E entirely because of its potential effect on MAPP members, especially the MAPP Generation Reserve Sharing Pool (GRSP). Xcel is similarly concerned with their right to withdraw from reserve sharing groups.

#### c) Discussion

420. Section 68.1.1.d states that market participants that are currently members of reserve sharing groups must receive prior approval from the Midwest ISO before withdrawing from such groups.[237] As the entity with the exclusive responsibility to be the Reliability Authority, the Midwest ISO must maintain system reliability, including managing reserves availability. The Midwest ISO and MAPP have signed an agreement recognizing the Midwest ISO's status as Reliability Authority. The Midwest ISO does not explain the source of its authority to impose this requirement, however. We will require it to do so.

### 6. Commission Directives

421. We will accept Module E for a limited transition period, subject to a Midwest ISO compliance filing, within 60 days, listing the date when it proposes to file a permanent RAR plan with the Commission. We emphasize that our approval of Module E is as a short-term transition mechanism to ensure that the day-to-day reliability needs are met similar to the way they are today. However, expeditious progress toward a permanent RAR plan for the entire Midwest ISO region is essential. We will sunset the interim tariff sheets contained in Module E when the permanent RAR tariff sheets are approved by the Commission.

422. We direct the Midwest ISO to file additional support about the specific resources that may qualify as Network Resources within 60 days of the date of this order. We direct the Midwest ISO to use its existing definitions of DNRs in lieu of a new definition in Section 69.2. The Commission directs the Midwest ISO to file the procedures for Alternative Capacity Resources to qualify to meet DNR requirements within 60 days of the date of this order. In general, we find it is acceptable to net alternative capacity resources like behind-the-meter generation and use them to meet DNR requirements. This is consistent with our policy of encouraging demand response programs, and we direct the Midwest ISO to use the recent order in Docket No. ER04-608-000 for guidance.[238]

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[237] Module E, Section No. 68.1.1.d, Original Sheet No. 811.

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

## I. *Attachment L: Credit Policy*

### 1. General

#### a) The Midwest ISO's Proposal

423. The Midwest ISO proposes its credit policy in Attachment L of the TEMT filing. Its goal is to strike a balance between maximum participation in the market through security requirements that are not excessive, and minimizing market participants' exposure to the risk of default. The Midwest ISO states that these provisions strike that balance by providing the information and financial requirements that market participants need to establish and maintain creditworthiness. The Midwest ISO states that the proposed credit policy in Attachment L is very similar to the credit policy of PJM that the Commission has previously approved.[239]

424. The Midwest ISO intends the credit policy filed in Attachment L to be generally applicable to all market participants, Transmission Customers, and Applicants (collectively "the participants") engaged in all forms of market activity. It outlines the various obligations, forms of financial security, and requirements, the violation of which may result in a default. It describes the requirements to establish one or more Credit Agreements, an Unsecured Credit Limit, Total Potential Exposure calculations, and the Total Credit Limit of each participant.

#### b) Protests and Comments

425. Various commenters asked the Commission to reject in their entirety the creditworthiness provisions contained in Attachment L, or in the alternative, to reject portions of the policy. General requests for complete rejection are addressed in the subsequent discussion section. Protests to specific aspects of the creditworthiness proposal are addressed in subsequent sections.

426. LG&E requests a Commission rejection of the credit policies proposed by the Midwest ISO as unjust and unreasonable because they mandate market participation and change the state/federal jurisdictional relationship in violation of the FPA section 201(b)(1).

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[239] Holstein testimony at 4.

#### c) The Midwest ISO's Answer

427. In its Answer, the Midwest ISO states that it does not believe that the credit policy is overly restrictive. As evidence of this, the Midwest ISO cites extensive stakeholder discussions that helped to produce the policy, and the intent to balance the competing interests of various participants. The Midwest ISO notes that smaller entities may have trouble participating in the Energy Markets. However, it rejects comparisons that the cooperatives and municipals made between the present tariff filing and industry benchmarks set in prior Commission orders regarding Entergy and Carolina Power & Light tariffs,[240] because those orders related to tariffs that were transmission-only, whereas this tariff includes an energy market. Instead, the Midwest ISO argues the more relevant benchmark is Commission precedent in PJM and NYISO proceedings.

428. Furthermore, the Midwest ISO notes that the present filing does not preclude any stakeholder from participating in the Credit Practices Task Force meetings. The Midwest ISO encourages stakeholders to participate in the task force meetings, in which the Midwest ISO is presently revisiting the credit scoring model that it currently uses to develop the credit scores used in Table 1.

#### d) Discussion

429. We conditionally accept the Midwest ISO's credit policy in Attachment L, subject to modifications and clarifications, as directed herein, through a compliance filing within 60 days of the issuance of this order.

430. General features of credit policies that the Commission has previously accepted in other RTO and ISO markets are the necessary guide for future decisions. This is particularly true in the Midwest ISO, as it moves toward a joint and common market with PJM. While the Commission recognizes that different markets, at different stages of maturity, may require slightly different credit policies, certain underlying principles should remain constant. Effective credit policies contain balance in their rules between participants large and small, balance between the need to ensure maximum participation through extension of credit and minimal amounts of uplift through default, and balance between the length of the billing cycle and the amount of exposure in the market.

431. We note that there are implicit trade-offs needed to achieve balance between competing objectives, in that financially smaller participants have different needs than larger ones, more unsecured credit extended means larger potential defaults, and longer

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[240] *See* Entergy Services, Inc., 104 FERC ¶ 61,329 (2003); Carolina Power & Light Company, 103 FERC ¶ 61,159 (2003).

invoice times mean more collateral to cover exposure. While the convergence of these competing agendas may not be available at market onset, it does not diminish the need for continual progress to achieve the proper requirements for financial security, unsecured credit, and billing cycles.

432. We are encouraged that the Midwest ISO has engaged stakeholders to develop its credit policy, and we require it to continue to do so.[241] We recognize the effort on the Midwest ISO's part to ensure that municipal and cooperative members are able to participate in the Energy Markets.[242] We also acknowledge that the Midwest ISO is cognizant of the need to ensure that its credit policies are similar to those in PJM as the two RTOs transition to a joint and common market.[243] The credit policies of other established energy markets have undergone continual refinements to better reflect the needs of all affected parties. We expect that same evolution to take place in this market. We note that this Order does not foreclose further modifications to the Midwest ISO's credit policy, either through future Midwest ISO filings or Commission directives.

### 2. Unsecured Credit Allowance and Table 1

#### a) The Midwest ISO's Proposal

433. Each participant must have a completed Credit Application on file with the Midwest ISO. In addition to completing the credit application, each participant will be subject to a credit evaluation. This evaluation is designed to review the participant's financial indicators of credit strength and their amount of expected exposure in the market. The completed initial evaluation will be used to generate a Credit Score, which is a numeric score ranging from one to six, where a score of one indicates the use of the most unsecured credit and a score of six represents the use of the least unsecured credit.

434. This score is converted to an Unsecured Credit Allowance extended to a market participant as a percentage of one of the following measures: (1) tangible net worth; (2) operating cash flow; or (3) working capital. The participant's core business determines which of these three categories applies and the maximum percentage of

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[241] We apply the "due deference" standard here as in previous Commission orders on the credit policies of PJM and NYISO. *See* PJM Interconnection, L.L.C.,104 FERC ¶ 61,309 at P 19 (2003), *reh'g pending*; New York Independent System Operator, Inc. 104 FERC ¶ 61,311 at P 29 (2003).

[242] *See* Holstein testimony at 7-8.

[243] *See* Holstein testimony at 4.

unsecured credit that the participant is eligible to use. The Midwest ISO proposes to divide participants into 5 business sectors: (1) Trading and Marketing; (2) Investor-Owned Utilities; (3) Independent Power Producers; (4) Public Power Entities; and (5) Industrial End Users. After participants are placed into a category, they are given a credit score to determine the amount of unsecured credit to extend to them. For example, an Investor-Owned Utility with a credit score of 1.00 may be extended six percent of their tangible net worth. The maximum unsecured credit allowance is $50 million per applicant. A matrix that lists the percentage values for participants in all business sectors appears in Table 1 of Attachment L.[244]

### b) Protests and Comments

435. Municipal and cooperative participants AMP-Ohio, Great Lakes, NRECA and Southwestern comment that the Table 1 proposal is not clear, and they are concerned that it may not give them an adequate allowance of unsecured credit. AMP-Ohio argues that when calculating unsecured credit grants, Table 1 does not: (1) accurately reflect the ability of municipals in Ohio to set their own rates for retail service; (2) outline the formulas used to establish unsecured credit; or (3) give an example showing the formulas used to calculate the actual credit limit. NRECA suggest that in lieu of Table 1, the Midwest ISO should use the financial ratings system commonly employed for Rural Utilities Service borrowers with a Times Interest Earned Ratio (TIER) of 1.05 or better and Debt Service Coverage Ratio (DSCR) of 1.00 to determine the amount of unsecured credit to grant.[245] Great Lakes argues that participants should have the explicit right to request written justification for the Midwest ISO's total exposure and total credit limit calculations, and a meeting with the Midwest ISO's financial/risk management personnel to review the Midwest ISO's creditworthiness calculations.

436. Other participants have concerns that the Table 1 proposal is unclear and discriminatory to groups of affected parties. Strategic and Epic and SESCO protest the lack of justification given for the percentages in Table 1 or definitions of tangible net

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[244] Attachment L, Original Sheet No. 1246.

[245] Debt Service Coverage (DSCR) is a ratio of Net Operating Income divided by the cost of Total Debt Service. A ratio of 1.00 or better would indicate that net income could service the total debt obligations on an annual basis; for example: Operating Income of $1,000,000 divided by $1,000,000 in Debt Service equals a 1.00 ratio.

Times Interest Earned (TIER) is a ratio of Profit before Interest and Tax expenses divided by Total Interest Charges, and this would demonstrate how frequently a company earns its interest payments in a given year.

worth, working capital, and operating cash flow. Strategic requests that the Midwest ISO modify the language governing Table 1 to state that it will use the least-cost option among the alternative parameters to establish an unsecured credit allowance. Epic and SESCO ask the Commission to reject the unsecured credit limit because it discriminates against the financial marketers and will discourage trading activity in the Energy Markets. In general, Epic and SESCO found the credit policies proposed by the Midwest ISO excessive compared to the other ISOs and contrary to Commission precedent. They urge the Commission to order the Midwest ISO to continue to work with stakeholders to revise and refine the credit policy.

#### c) Discussion

437. We find that the Midwest ISO has not adequately explained the methodology that underlies its proposed Table 1. We disagree with Michael Holstein's statement that the PJM and Midwest ISO Table 1 "use virtually the same criteria."[246] Similar tables in PJM and NYISO only display a credit score and tangible net worth matrix to determine the amount of unsecured credit permitted for a participant; they do not distinguish among business sectors.[247] However, in the Midwest ISO's proposed Table 1, a participant classified as Trading and Marketing with a credit score between 0 and 1.82 is permitted 2.5 percent of its tangible net worth as unsecured credit, whereas an Investor Owned Utility with the same credit score may receive six percent, and an Independent Power Producer would be entitled to 4 percent. These distinctions are not made in PJM or NYISO, and the Midwest ISO did not provide sufficient justification to require different standards. Therefore, we direct the Midwest ISO to refile Table 1 with a matrix similar to PJM's or NYISO's or to thoroughly justify any differences through a compliance filing. In addition, Section II (B), Original Sheet No. 1219, lists a credit score range of 1 to 6. This conflicts with the scores in Table 1, which run from 0-6. The Midwest ISO is directed to explain or eliminate this discrepancy.

438. Furthermore, although Operating Cash Flow limit may be an appropriate financial metric capable of quickly reflecting changes in a participant's creditworthiness status, it is not the primary parameter used for any business sector in Table 1; the Midwest ISO

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[246] Holstein testimony at 9.

[247] *See* PJM OATT at Attachment Q, Original Sheet No. 523G; NYISO OATT at Attachment W, First Revised Sheet No. 736. We note that when NYISO performs its credit assessment of a municipal electric system, it starts with $1 million, without regard to the municipal system's tangible net worth. At the municipal system's request, the municipal system may submit to a tangible net worth test in lieu of the $1 million starting point.

intends to use it at its own discretion; and the Midwest ISO did not explain its function or justify its inclusion. Therefore, we direct the Midwest ISO to define in Module A the financial measures: (1) Tangible Net Worth; (2) Working Capital Limit; (3) Operating Cash Flow; and (4) any other undefined terms that it intends to use in conjunction with Table 1.[248] In addition to defining all relevant terms, the Midwest ISO must include calculations and justifications for each.

439. We direct the Midwest ISO to adopt an unsecured credit "floor," similar to the one in use in the NYISO markets, in its credit assessment of public power participants to ensure their ability to fully participate in the Midwest ISO markets.[249] However, we note that the Commission has previously allowed PJM to retain some discretion in its credit policy to consider alternative measures to determine financial strength and creditworthiness for cooperative and municipal participants. We accept the Midwest ISO's proposal to retain the same discretion in its credit policy.[250] That discretion is permissible so long as it does not work to exclude otherwise creditworthy participants.

### 3. Market Activity Categories and Total Potential Exposures

#### a) The Midwest ISO's Proposal

440. The Total Potential Exposure is the cumulative financial obligation that a participant has incurred through engaging in various market activities. This calculation will vary based on the participant's identification as either a Category A or a Category B participant.[251] If a participant's Total Potential Exposure exceeds ninety percent of its Total Credit Limit, the participant will be notified in writing. If a participant equals or exceeds its Total Credit Limit, the participant will be directed to pay invoices to reduce credit exposure and/or post additional financial security to raise its credit limit. The Total Credit Limit is the sum of the unsecured credit allowance, extended through Table 1, and

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[248] For guidance we direct the Midwest ISO to review the NYISO OATT, Fourth Revised Sheet No. 69.

[249] *See* NYISO OATT, Attachment W, Original Sheet No. 729B.

[250] *See* PJM, Attachment Q, Original Sheet No. 523 C&F, where it states that, "In the credit evaluation of Cooperatives and Municipalities, PJM may request additional information as part of the overall financial review process and will consider other alternative measures in determining financial strength and creditworthiness." This is mirrored in Attachment L, Original Sheet No. 1216.

[251] *See* Attachment L, Original Sheet No. 1222.

the amount of financial security provided through the form of a cash deposit or irrevocable letter of credit. A portion of the Total Credit Limit must be devoted to the FTR auctions, if the participant chooses to engage in these auctions.

441. Category A participants are those that grant the Midwest ISO a first-priority security interest in their accounts receivable; Category B participants are those that do not. The market activities are grouped into six categories: (1) FTR portfolio; (2) Real-Time Energy Market and Day-Ahead Energy Market transactions; (3) Virtual Transactions; (4) Congestion and Losses; (5) Transmission Service; and (6) FTR auction activity. The Midwest ISO will net the market activities both within these categories and across them to determine the potential exposure for Category A participants so that a credit in one category may be used to offset a debit in another category. For Category B participants, the Midwest ISO proposes that if the exposure within a category is a net credit amount, the credit amount for that category is excluded from the Total Potential Exposure calculation or in other words, there is no ability to net credits against debits.[252]

### b) Protests and Comments

442. The Midwest TDUs are concerned with the Midwest ISO proposal to only allow netting within and across all areas of market activity for those entities that post a first-priority security interest in all accounts receivable. They state that granting first-priority security interest to the Midwest ISO may not be possible for public power entities due to the nature of their debt financing and it is therefore improper for the Midwest ISO to calculate their Total Potential Exposure differently. AMP-Ohio would like revenues from FTRs to be netted against congestion charges when determining the participant's exposure. NRECA shares in these netting concerns with respect to electric cooperatives. Reliant shares the concern that the Midwest ISO will not allow netting within and across all categories when calculating the total potential exposure for a Market Participant. Reliant suggests that this creates a hypothetical exposure that the Midwest ISO does not face and therefore the Commission should reject the Midwest ISO proposal and require netting within and across all areas of market activity. If the Commission decides to allow the netting methods to differ across market activity areas, Reliant suggests that the Midwest ISO be required to at least net across all categories of the Energy Markets, including the congestion component of such charges. Furthermore, Reliant argues that the term Category B participant is not defined, and therefore the Midwest ISO should remove or define it. Strategic argues that it is unreasonable for the Midwest ISO to eliminate credits from the total potential exposure calculation that could potentially reduce their collateral costs.

[252] *See* Attachment L, Original Sheet No. 1231.

443. Companies that receive all revenues from transmission service have unique concerns with the Midwest ISO's proposal to only allow netting for certain categories of market activity. ATCLLC believes that the Midwest ISO has inappropriately blended the risk associated with the energy market transactions and the risk associated with the underlying transmission service because Attachment L does not recognize that ATCLLC is not a Market Participant, that it receives 100 percent of its revenues from transmission, and that under the Transmission Owners Agreement, the Midwest ISO must act on its behalf as its agent. ATCLLC states that it is not a public utility and therefore it will be harmed by the proposal to net or set off amounts owed to a bankrupt participant against amounts owed to the Midwest ISO. ATCLLC states that this language may deny it credit protection and the right to avail itself of protections in section 366 of the Bankruptcy Code.[253] To remedy what it views as a potential problem, ATCLLC suggests that rather than aggregate the total security into one instrument, the Midwest ISO, once it calculates the combined credit exposure, should divide the security posted and allocate a portion to the transmission service charges and a portion to the energy charges. ATCLLC is also a party to the Midwest SATCs' comments, which mirror ATCLLC's concerns with regard to the separation of transmission and energy market revenues and security. ATCLLC requests that the Commission direct the Midwest ISO to provide the results of its credit analysis of the various parties that receive service on the ATCLLC transmission system.

444. Epic and SESCO protest the proposal to treat collateral for FTR auctions separately. They also protest the Virtual Transactions requirement to post collateral to cover the value of six days of bids and offers, without regard to whether the bids were accepted. Instead, they argue that the Midwest ISO should use a one-day multiplier.

445. AMP-Ohio has concerns with the requirement that a Market Participant has two business days to reduce its exposure to the market below its financial assurances. AMP-Ohio states that its diverse membership, which is composed of various political subdivisions, will not be able to approve additional financial assurances within the two-day time period and that then they will enter default status. Therefore, AMP-Ohio suggests modifications to the tariff to permit political entities to submit to the Midwest ISO at any time a blanket request for two additional days, or four business days total, to provide the necessary financial payment. NRECA also has concerns about the requirement to provide additional financial security within two business days or risk termination of transmission service. To address this concern, NRECA suggests that the Midwest ISO review the credit requirements for transmission service separate from the other areas of market activity, and allow at least 10 business days for a cooperative to

[253] 11 U.S.C. § 366 (2000) (providing conditions under which a utility may and may not alter, refuse or discontinue service to a bankrupt customer).

respond to a request for additional collateral. NRECA also filed an answer in response to the Midwest ISO's answer in which it reiterates its argument that the credit policy proposal puts cooperatives at a disadvantage and should be rejected. NRECA also states that because the credit scoring model is still under discussion in the stakeholder process, where smaller entities may not have the resources or ability to participate in or influence those discussions, the Commission should reject the credit policy proposal as incomplete.

### c) Discussion

446. We conditionally accept the Midwest ISO's proposal to net market activities, contingent upon compliance with the directives below. Participants' ability to net their various market activities against each other to reduce collateral costs is consistent with prior Commission policy on netting current obligations across the NYISO markets.[254] We find that similar methodology is appropriate here. However, we require clarifications and modifications to the provisions for virtual transactions, total potential exposure calculations, and granting the first-priority security interest.

447. We agree with commenters that the Midwest ISO did not adequately justify its inclusion of a six-day collateral window for virtual transactions.[255] In general, we agree with comments that virtual trading provides benefits to the market by increasing liquidity and price convergence between the Day-Ahead and Real-Time Markets. Although we note that the NYISO markets currently use a seven-day collateral window for virtual transactions, that provision was granted as an interim measure only, and it was expected that the collateral requirements would decrease over time.[256] In keeping with precedent and to facilitate the virtual transaction activity, we direct the Midwest ISO to adopt a two-day collateral window, through a compliance filing, in the same manner as we directed for PJM.[257] In addition, we direct the Midwest ISO to clarify the proposed "MPD"

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[254] *See* New York Independent System Operator, Inc., 104 FERC ¶ 61,311 at P 51-52 (2003), *clarification granted*, 105 FERC ¶ 61,340 at P 17 (2003). In those orders the Commission determined that although FTRs may bring in future revenues, those future monies were not guaranteed, and therefore could not be netted.

[255] Attachment L, Section III A (1), Original Sheet No. 1223.

[256] 97 FERC ¶ 61,091 at 61,474, *reh'g denied*, 98 FERC ¶ 61,077.

[257] PJM Interconnection, L.L.C., 104 FERC ¶ 61,309 at P 23 (2003). We note that this proceeding is ongoing and that PJM was directed to report on the feasibility of a one-day credit window. The collateral window in the Midwest ISO will begin as two days at market startup, but may be revisited in the future.

calculation, particularly the definition of the "proxy" it refers to, and explain why the Midwest ISO does not accommodate seasonal variations in the calculation through the use of a price differential that is less than 12 months.[258] We note that PJM uses a rolling two-month reference period, and NYISO uses a rolling 90-day window.[259] Furthermore, we direct the Midwest ISO to clarify the Virtual Transactions Credit Requirement by filing in Section III A(1), Original Sheet No. 1223, a definition of each of the three acronyms used to calculate this requirement. Such a clarification should include what each letter of the MPD, the DMWhL, and the VMEW stands for.

448. We are not convinced that the Midwest ISO will not know the extent of a participant's actual risk exposure within the six-day time frame.[260] After each operating day, the Midwest ISO should know which bids were accepted and which were not. We direct the Midwest ISO to study, with stakeholder involvement, the feasibility of moving to a one-day virtual transactions collateral window and the potential impact on the design of the Midwest ISO settlement system and report the results of this analysis to the Commission within 180 days. This analysis should also explain the maximum level of exposure any participant could incur, including the total cost of collateral, and possible flexible settlement options.[261]

449. It is not clear to the Commission why it is necessary to require a participant in the FTR auction process to dedicate a portion of its total credit limit to such activity above and beyond their other creditworthiness obligations. It appears that if the values of the total FTR auction bids, along with any other market activities, do not exceed the total credit limit requirements, the participant has satisfied its creditworthiness requirements and should not need to enter into separate FTR credit agreements with the Midwest ISO.[262] It is also unclear how a virtual bid and an FTR bid, which are both financial

[258] *See* Attachment L, Section III(A)(1), Original Sheet No. 1223.

[259] *See* PJM OATT, Attachment Q, Substitute Original Sheet No. 523I.01; NYISO OATT, Attachment W, First Revised Sheet No. 734.

[260] *See* Holstein testimony at 40.

[261] For guidance, the Midwest ISO should refer to PJM Interconnection, L.L.C., 104 FERC ¶ 61,309 at P 21-28 (2003), *reh'g pending*, which directed PJM to study and report on actual credit risk exposure.

[262] *See* Attachment L, Section III B(2), Original Sheet No. 1227 and Exhibit II to Attachment L, "Acknowledgement and Certification of Understanding of Midwest ISO Financial Security Policy and Procedures for FTR Auctions".

instruments, differ so substantially, other than in duration, that they require different credit policies. Therefore, we direct the Midwest ISO to clarify and sufficiently justify the necessity of additional creditworthiness requirements beyond those that apply to virtual transactions or other market activities. Should the Midwest ISO retain distinct FTR Credit Auction requirements, then we direct clarifications in the acronyms used for the calculation similar to those directed for virtual transactions. This includes the acronyms: MPB, MNB, P, and G outlined in Section III B(1), Original Sheet No. 1226.

450. We find that the Midwest ISO did not adequately justify in Section II(G) its need and authority to require participants to grant the Midwest ISO a first-priority security interest in accounts receivable.[263] We share commenters' concerns that they may not be able to comply with this directive if it conflicts with state law or debt financing covenants. Participants that cannot comply with the requirement are placed into Category B status, with restrictions on their ability to net market activities and thus potentially higher collateral costs. While the Commission empathizes with the Midwest ISO's desire to preserve its rights to collect monies due, as bankruptcy law allows, this neither negates the need for credit policies that participants can legally comply with nor justifies a requirement that is not present in the credit policies of other ISOs and RTOs. Therefore, we direct the Midwest ISO to remove the Category A and B language from the TEMT.

### 4. Credit Policy in the TEMT versus the Business Practice Manuals

#### a) The Midwest ISO's Proposal

451. In general, the Midwest ISO proposes to post the formulas used to calculate a participant's Total Potential Exposure for the relevant areas of market activities in the Credit Business Practice Manuals and amend them from time to time.

#### b) Comments and Protests

452. AMP-Ohio and Consumers request that the Midwest ISO clarify Section IV(A) of Attachment L, regarding whether the credit policy in Attachment L or the Credit Business Practices Manual is the prevailing document that governs the formulas and calculations used. AMP-Ohio submits that the entire credit policy should be maintained in the tariff and that any changes to the policy should be filed as a change to the tariff. Epic and SESCO ask the Commission to direct the Midwest ISO to file the Business Practices Manuals it is relying on for areas of the Credit Policy.

[263] Attachment L, Original Sheet No. 1222.

#### c) Discussion

453. We agree with the comments that it is not always clear whether the Credit Policy Business Practice Manual or the TEMT is governing document for formulas and calculations used to compute a participant's Total Potential Exposure. It is also unclear where, within the Credit Policy Business Practice Manual, to find the necessary information. The Commission has previously said that the tariff is the appropriate place for all matters affecting rates, terms and conditions of jurisdictional transactions regarding creditworthiness and collateral requirements.[264] Therefore, we direct the Midwest ISO to file, within 60 days, all formulas relating to the Total Potential Exposure calculation, for all categories of market activity. Furthermore we advise the Midwest ISO that changes to the creditworthiness standards are changes to the tariff, subject to review by the Commission; as such, they should be filed under section 205 of the FPA.[265]

### 5. Financial Reporting and Financial Security

#### a) The Midwest ISO's Proposal

454. The Midwest ISO requires applicants to submit financial statements and report other related information to perform the financial review during the initial and ongoing credit evaluation process. As a part of their initial evaluation, the Midwest ISO requires publicly traded applicants to submit annual, quarterly, or current reports that are filed with the Securities and Exchange Commission (SEC). Privately held applicants must submit financial statements, such as balance sheet, income statements, and cash flow statements. All applicants are also required to submit: (1) references; (2) information on litigation, commitments and contingencies; (3) disclosures, such as ongoing SEC investigations; (4) estimated annual peak load data; (5) virtual transactions designations; (6) FTR auction designations; and (7) other information. Existing transmission customers that are applying to become market participants do not need to provide the information required for the initial credit evaluation because this information is already on file with the Midwest ISO.

455. As a part of the ongoing credit evaluation, on at least an annual basis, the Midwest ISO will require participants to submit: (1) audited annual and quarterly financial statements; (2) publicly traded companies submit annual, quarterly, and current reports,

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[264] *See* New York Independent System Operator, Inc., 98 FERC ¶ 61,282 at 62,217 (2002).

[265] Further filing requirements relating to Module A, Section 7, Billing and Settlements, are listed in the subsequent section of this order.

and privately held must submit balance sheet, income statements, and cash flow statements; (3) material changes to financial condition; (4) information on litigation, commitments, and contingencies; and (5) other disclosures.

456. The Midwest ISO lists the terms of corporate guaranty and/or acceptable forms of financial security in Attachment L. Generic forms of each type of acceptable financial security are listed as exhibits to Attachment L. Generally, where the applicant or participant is an affiliate of another entity and would like to use the financial statements of its parent company to obtain credit, a signed corporate guaranty is required. In this instance the credit evaluation is conducted for the guarantor, who is subject to the financial standards of Attachment L, and the total amount of unsecured credit extended remains $50 million total. If the guarantor is also an applicant or a participant, or it guarantees multiple participants' obligations, the amount of unsecured credit is portioned according to the Midwest ISO's discretion. The acceptable forms of financial security listed in Attachment L are: (1) cash deposits; and (2) irrevocable letter of credit. Cash deposits are placed into segregated accounts, held by the Midwest ISO, to secure the payment of the participant's obligations. Cash deposits require the completion of the Cash Collateral Agreement (Exhibit V of Attachment L) and interest accrues to the benefit of the participant. Accrued interest that has not been used to satisfy obligations will be paid to the participant semi-annually, unless there is an ongoing default. If any portion of the deposit is used to pay a participant's obligations, the deposit must be replenished within ten business days. Irrevocable letters of credit must be issued by a financial institution that has a minimum corporate debt rating of an "A-" by S&P, "A3" by Moody's, "A-" by Fitch or the equivalent. The irrevocable letter of credit automatically renews annually, unless the issuing financial institution provides notice to terminate it 120 days prior to its expiration date. An acceptable form of an irrevocable letter of credit is listed as Exhibit IV of Attachment L.

### b) Protests and Comments

457. Consumers argues that the financial statements requirement contained in Section I (A)(2) of Attachment L, to provide information on litigation, commitments, and contingencies, is unnecessary because all of this information is available to the public on standard dates through the Securities and Exchange Commission's EDGAR website. Xcel believes that Attachment L, Section I (A)(4) should clarify what information participants need to provide to the Midwest ISO and the timeline for such information requests from the Midwest ISO. Consumers argues that in Section I (B) there is no need to submit the information to conduct the ongoing credit evaluation because it is duplicative of the information needed for the initial credit evaluation. In Section I(B)(3) the notification time to provide the required financial security should be changed to Eastern Prevailing Time from Eastern Daylight Time, as EDT only refers to when the Eastern Time Zone is observing Daylight Savings Time.

458. Strategic, Consumers and Xcel protest the Midwest ISO's proposal for acceptable forms of financial security. Strategic contends that the Midwest ISO should not determine which form of allowable financial security is most appropriate for each participant. According to Strategic, various businesses have certain preferred methods of supplying credit support, and a participant, not the Midwest ISO, should determine which method it prefers from among the acceptable choices. Xcel requests an additional qualifier in Section I (A)(1) relating to rating agency reports that states, "not enhanced by third-party support" where the phrase "unsecured senior long-term" occurs in the tariff as this is the standard in the industry to protect against a market participant arguing that their enhanced rating qualifies them for additional credit. Xcel believes that Section V(B)(2), should refer to "standby" irrevocable letters of credit, because presumably such letters of credit would only be used in a case of default. Consumers contends that the exhibit stating the Corporate Guaranty lists Indiana state law as governing, and instead it should state that New York state law will govern as it is more widely understood and it is the generally accepted standard for financial agreements. Finally, Consumers asks that the Corporate Guaranty-Resolution to the Board of Directors requirement should not require a unique resolution pertaining to each guaranty, but a recognition that the appropriate board consent has been given.

### c) Discussion

459. We deny protests of the Midwest ISO's financial information requirements in Section I (A) and (B) for initial and ongoing credit evaluations. We find these data requirements to be consistent with the financial data requirements of previously approved credit policies and not unduly burdensome to participants.[266] The information that the Midwest ISO requires participants to provide is essential to the Midwest ISO's ability to accurately assess the creditworthiness of the applicant. We note that to lessen the data burden on applicants, the Midwest ISO has included a provision stating that if information is available on the Internet, applicants may provide the Midwest ISO a letter stating where the documents may be retrieved, and if the applicant files annual, quarterly, or current reports with the SEC then they have met the requirement of locating the information on the Internet.[267]

460. We generally accept the provisions included in Attachment L that govern the posting of financial security. Cash deposits, corporate guaranty, and irrevocable letters of credit are standard instruments in use in other RTO and ISO markets and their use is

[266] Similar language is found in the Commission-approved tariff of PJM, Attachment Q, Original Sheet Nos. 523B & 523C.

[267] *See* Attachment L, Original Sheet Nos. 1210, 1216.

appropriate in the Midwest ISO market. However, we agree with Consumers in regards to the rate and release date for interest that has accrued to the benefit of a participant. We direct the Midwest ISO to explicitly state in Section V (B)(1) the interest rate and methodology used to calculate any interest that accrues to the benefit of participants that post cash deposits, and revise Exhibit V, the Cash Collateral Agreement accordingly. We further direct the Midwest ISO to revise Section V (B)(1) to release and pay interest on a quarterly basis, and Exhibit V, the Cash Collateral Agreement. These directives are consistent with the previously-approved relevant Sections of the PJM creditworthiness provisions.[268]

### 6. Billing/Invoicing

#### a) The Midwest ISO's Proposal

461. The Midwest ISO proposes to divide its billing procedures among different areas of services that it provides under Section 7 of Module A. Sections 7.1, 7.2, 7.4 and 7.5 apply to Transmission Customers and Transmission Owners; Sections 7.6 through 7.10 apply to market participants; and Sections 7.3 and 7.11 through 7.17 apply to all tariff customers. For purposes of invoicing, a distinction is made between Transmission Customers, Transmission Owners, and market participants. An ITC may elect to perform billing/invoicing functions in lieu of the Midwest ISO.[269]

462. Transmission Customers will be billed each month through two invoices – one invoice for all services furnished under Module B to the Transmission Owners, and a second relating to the cost adder for recovering costs associated with operating the Midwest ISO that are not covered under Schedules 1, 16, or 17. These costs are captured within Schedule 10 and include the costs for the control center, including capital costs and operating expenses, and costs for administering the tariff. Transmission Customers listed in Attachment I pay costs associated with the Transmission Provider's operating expenses under Schedule 10-A. Transmission Customers must pay their invoices within 15 days of receipt. Transmission Owners listed in Attachment I receive an invoice each month for their share of the Transmission Provider's monthly capital costs and a portion of its operating costs described under Schedule 10-B. Transmission Owners must pay their invoices within 10 days of receipt.

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[268] *See* PJM Open Access Transmission Tariff, Attachment Q, Original Sheet No. 523J.

[269] We note that Attachment L, Original Sheet No. 1206, requires every Transmission Customer of the Transmission Provider to apply to be a Market Participant or be represented by a Market Participant.

463. If a Transmission Customer has not paid all charges when their 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. Initially, the Midwest ISO will use any monies received to pay all amounts due to the Transmission Provider under the TEMT and the Midwest ISO Transmission Owners Agreement.[270] Next, the Midwest ISO will use funds in the Credit Support Documents, to the extent necessary, to pay the past due amount and any and all late charges. After using the credit support monies, if there are still insufficient funds to pay all invoiced amounts in full, the Midwest ISO will reduce payments to those Transmission Owners or ITCs that are owed money, to the extent necessary to clear accounts. As the Midwest ISO receives additional past due funds, it will distribute such funds *pro rata* to the Transmission Owners or ITCs that did not receive full payment. Additional payments received to settle past due amounts will be distributed to the oldest debts first. Once the customer is in default, the Midwest ISO will initiate a filing with the Commission to terminate the Transmission Customer's service agreement. Generally, termination of service will not occur until the Commission approves such a request.

464. Transmission Customers have the right to dispute amounts invoiced under Sections 7.1 and 7.2, in Section 7.5, but the customer must pay all invoiced amounts regardless of any dispute. If the Transmission Customer notifies either the ITC or the Midwest ISO, whichever is applicable, of the dispute prior to or at the time of payment, then the Midwest ISO will place the disputed amount into a separate account pending resolution of the dispute.

465. Market participants will be billed through two invoices for the charges of all services and goods furnished under Module C, based on a schedule in the market settlements timeline as posted on the Midwest ISO extranet website. One invoice will relate to the net credit or debit amount of all market activities, subject to the Midwest ISO's right to be paid first under Section 7.8(a) and the setoff and recoupment rights set forth in Section 7.17. The second invoice relates to the service charge for recovering costs associated with operating the Energy Markets, including the costs under Schedules 16 and 17. All invoices with net charges are to be paid within 7 days of receipt. All invoices with net credits will be paid by the Midwest ISO within 24 to 48 hours after the invoice due dates, in accordance with the procedures listed in the Settlements Business Practice Manual.

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[270] Sheet No. 162.

466. 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 Section 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. If unpaid charges remain, the Midwest ISO will reduce payments to market participants *pro rata*, based on the net credit invoiced amounts, to the extent necessary to clear its accounts on the date such payments are due. As the Midwest ISO receives additional funds prior to the past due amounts being declared an Uncollectible Obligation as discussed below, the Midwest ISO will distribute them *pro rata* to market participants that did not receive the full amount they were due. Payments received will be used to satisfy outstanding amounts according to the order of creation of the debts. As with Transmission Customers, market participants have the right to dispute charges in Section 7.9.

467. After pursuing all reasonable efforts to collect outstanding past due amounts, the Midwest ISO will declare the remaining unpaid past due amounts to be an Uncollectible Obligation. Uncollectible Obligations are recovered through Section 7.10. This Section includes provisions to determine eligibility of other participants to share in any uplift of uncollectible amounts through a formula to determine the proportion of uplift for the week's invoicing cycle.[271]

468. 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.

469. 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 previously mentioned 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

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[271] Uplift of Uncollectible Default Amounts is discussed separately in a subsequent section of this order.

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.

### b) Protests and Comments

470. AMP-Ohio has numerous requests for modifications and clarifications in Section 7 and Section 11. It asks the Commission to direct the Midwest ISO to: (1) incorporate a default cure period of five business days for the Energy Markets; (2) add the qualifying word "reasonable" to Section 7.14(d); and (3) clarify Section 7.15, regarding notices, to state that only verifiable means of delivery, such as certified mail, are acceptable. AMP-Ohio states that it is without legal authority to agree to indemnify the Midwest ISO, and it seeks appropriate waiver provisions. AMP-Ohio and Southwestern argue that the last sentence of Section 11.1 should state that the official credit provisions are contained in Attachment L.

471. Numerous intervenors had comments about the Midwest ISO's proposal to invoice customers. AMP-Ohio is unclear whether the Midwest ISO's proposal is to use a weekly or monthly invoicing cycle, and it wants the Midwest ISO to explicitly state the Energy Markets invoicing cycle in Section 7.6. Southwestern protests the weekly settling and invoicing of the Energy Markets because as a small cooperative, it contends that it does not have the resources to manage weekly invoices from the Midwest ISO. Instead, Southwestern requests the alternative of monthly invoicing. Cinergy contends that the Midwest ISO should incorporate a time frame for the submission of invoices in the TEMT. Cinergy further requests that the Commission require the Midwest ISO to delete from Section 7.10, regarding uplift of uncollectible past due amounts, self-schedules and bilateral schedules in the calculation of participant's share of the uplift.

472. The Midwest SATCs support the Midwest ISO's proposal in Section 7.11 to require financial security from customers with a history of paying their invoices late. Furthermore, they suggest that the "all amounts due" clause in Section 7.4(a) should be revised to state "all amounts due under Schedule 10." The Midwest ISO TOs do not object to the default provisions of Sections 7.13(a) and (b). However, they protest as overly broad and in violation of Commission precedent the default provision contained in Section 7.13(c), which allows the Midwest ISO to declare a default for failure to comply with any portion of the tariff.

### c) Discussion

473. We agree with AMP-Ohio and others that it is unclear what the Midwest ISO proposes in regard to the billing timeline in Section 7.6, Billing Procedures for market participants. We direct the Midwest ISO to state in Section 7.6 of the TEMT that the

invoice schedule shall be weekly, and to clarify its procedures to invoice for the Energy Markets. However, we note that this does not preclude the Midwest ISO from posting its invoicing schedule on their website in tandem with filing it in the tariff. We note that although PJM uses monthly billing, the trend in energy markets is toward shortened settlement periods to reduce the potential exposure window and collateral requirements for all parties. For example, the Commission accepted a recent proposal from NEPOOL to use weekly billing.[272] Accordingly, we find that the Midwest ISO's proposal to invoice and bill on a weekly schedule is just and reasonable.

474. We agree with AMP-Ohio and Southwestern that Section 11.1 should be revised to include a sentence that states the Midwest ISO official credit policy is found in Attachment L. This will provide additional clarity and is consistent with the previously-approved, corresponding Section 11 of the PJM tariff.[273]

475. We direct the Midwest ISO to revise Sections 7.5 and 7.9 regarding disputed amounts. The Midwest ISO must include specific provisions for the resolution of invoicing disputes or a reference to direct readers to the relevant area of the tariff. Furthermore, Section 7.9 must mirror the language in Section 7.5 so that Transmission Customers and market participants have equal right to dispute invoice amounts.

476. We accept the Midwest ISO's proposal in Section 7.13 to allow for cross-defaults, or in other words, to treat a default in one category as a default across all categories. We find that it is just and reasonable for the Midwest ISO to prevent a Market Participant from defaulting in one area of market services, and yet continuing to operate in another. Furthermore, we accept that a bankruptcy filing is a default as listed in Section 7.13.d. Although such language is not clearly specified in the PJM Operating Agreement, we find the additional clarity provided by the Midwest ISO to be beneficial to all parties that will be subject to these default provisions. We accept the Midwest ISO's proposal to use a two business-day cure period for the Energy Market defaults and a ten business-day cure period for transmission defaults. However, we direct the Midwest ISO to revise the definition of default, in Section 1.62, to include a reference to the default provisions in Section 7.13 and list the distinct default timelines for Transmission Customers and market participants.

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[272] *See* New England Power Pool, 107 FERC ¶ 61,201 at P 10 (2004).

[273] *See* Outback Power Marketing, *et al.* v. PJM Interconnection, L.L.C., 105 FERC ¶ 61,106 at P 3 n.3 (2003).

477. We agree with the Midwest ISO TOs, with regard to their protest of the language in Section 7.14.a, that states that the Midwest ISO will take action to cure defaults "subject to the receipt of any approval from the Commission that may be necessary." We direct the Midwest ISO to either remove this language and replace it with "subject to the receipt of approval from the Commission," or identify any circumstances, other than in the circumstance where an alternate supplier is required under a state retail access program, in which the Midwest ISO would argue that it is appropriate to terminate service without prior Commission approval.[274]

478. We direct the Midwest ISO to remove the language in Section 7.8 stating that "upon the occurrence of a default, the Transmission Provider shall (i) suspend any pending Market Activities of the Market Participant and (ii) annul any eligible confirmed transmission reservations of the Market Participant" immediately and prior to Commission approval.[275] We also direct the removal of similar language in Section 7.4 that states, "upon the occurrence of a default, the Transmission Provider, or ITC where applicable, shall annul eligible confirmed reservations of the transmission customer…"[276] Annulments of eligible confirmed transmission reservations have previously been found to amount to termination of service, which is subject to Commission review and approval.

479. We agree with the comments that Section 7.14(d) should be revised to include the word "reasonable" relating to the collection of attorneys' fees. Accordingly we direct the Midwest ISO to remove the words "without limitation" and replace them with the word "reasonable."[277]

480. For the forgoing reasons, we direct the Midwest ISO to comply with the directives on billing and invoicing through a compliance filing no later than 60 days after the date of this order.

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[274] *See* PJM Interconnection, L.L.C., 95 FERC ¶ 61,215 at 61,712 (2001).

[275] Module A, Section 7.8, Original Sheet No. 172.

[276] Module A, Section 7.4, Original Sheet No. 161.

[277] PJM OATT Section 16.2, Original Sheet No. 52.

### 7. Uplift Charge for Uncollectible Default Accounts

#### a) The Midwest ISO's Proposal

481. After the Midwest ISO has exhausted all commercially reasonable efforts to collect unpaid debts, it proposes to recover the remaining unpaid debts associated with transactions in the energy markets from other market participants that received a Midwest ISO invoice during the same period of time as the unpaid invoice.[278] Each Market Participant, other than the Market Participant with the unpaid debt, is assessed a share of the unpaid debt based on its relative share of the absolute value of all charges and credits associated with invoices for market activities.

482. The Midwest ISO states that it evaluated all ISOs' and RTOs' methods of uplifting unpaid debts. According to the Midwest ISO, all ISOs and RTOs but CAISO uplift default amounts to their market participants. The CAISO pays market participants who are owed funds a *pro rata* share of the funds it has available as a means of addressing default on payments owed.[279]

483. The Midwest ISO states that the task force evaluating the uplift of unpaid debts issue recommended the uplift charge. However, as a result of the Midwest ISO's policy subcommittee being split over the issue, the Midwest ISO independently decided to propose uplifting unpaid debt amounts. The Midwest ISO explains that from a market design point of view, sellers in the market need certainty of payment in order to participate in the market. The introduction of uncertainty of payment may cause sellers to: (1) price the risk of non-payment into their bid prices, (2) limit their participation in a market, or (3) outright avoid the market and transact entirely on a bilateral basis in order to limit the risk of non-payment by the market. This could lead to fewer participants and less liquidity in the market, thereby reducing one of the primary benefits of an energy market – robust competition with liquid markets and transparent prices.[280]

484. The Midwest ISO provided the stakeholder advisory committee with two options to allocate such costs: (1) load ratio share or (2) gross dollar volume of market activity. By a vote of 2 to 1, the stakeholder advisory committee voted in favor of the gross dollar volume of market activity.

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[278] *See* Module A, Section 7.10, Original Sheet Nos. 173-75. The Midwest ISO has not proposed to uplift unpaid debts associated with transmission service.

[279] *See* Exhibit No. MISO-10 at p. 26.

[280] *See* Exhibit No. MPH-1 at p. 1 attached to Exhibit No. MISO-10.

### b) Protests and Comments

485. The Midwest ISO TOs state that the uplift charge is retroactive ratemaking as it imposes a surcharge to recoup past losses. The Midwest ISO TOs also claim that the uplift charge violates the notice requirements of the FPA because it subjects customers to potentially significant charges that they would have no ability to determine prior to their purchase of power. The Midwest ISO TOs recommend that limits be placed on this uplift because they claim that the uplift charge could be significant if a large load-serving entity fails to pay or declares bankruptcy, and because the uplift is largely imposed on native loads that would not have received any benefit from the transaction. Further, the Midwest ISO TOs state that the uplift proposal is contrary to commercial law, under which the seller of the product bears the risk of under-recovery.[281] The Midwest ISO TOs note that these under-recoveries should only occur if the Midwest ISO fails to do its job and receives inadequate credit assurances from a customer. The load-serving entities that would be charged this uplift have no control over those credit issues. Finally, the Midwest ISO TOs believe that the proposal is inequitable in that there is no similar uplift charge for transmission owners associated with transmission service revenues.

486. Municipal Participants are concerned about being an insurer backstopping other market participants that purchase energy in the market, but go bankrupt prior to making payment. Municipal Participants and IMEA ask the Commission to require the Midwest ISO to specify at least the minimum steps that it will take prior to determining that such amounts are uncollectible and engaging the use of the uplift charge.

487. LG&E criticizes the uplift charge because it socializes the market's credit risk and forces LG&E to subsidize entities such as marketers. Under the TEMT, load-serving entities like LG&E would become credit providers of last resort. LG&E also claims that the uplift provisions don't address the situation in which the Commission rejects the Midwest ISO's request to terminate an entity from market participation. If the Commission denies the termination of a provider of last resort, then presumably other market participants will share the burden of continued default costs. LG&E states that the uplift provision is unacceptable because it subjects non-defaulting market participants

[281] Midwest ISO TOs at 46 (citing Transwestern Pipeline Co., 65 FERC ¶ 61,113 at 61,671-72 (1993) (stating that the pipeline should bear the risk of failure of firm shippers to pay reservation charges because the pipeline determines which shippers are creditworthy); Northern Natural Gas Co., 102 FERC ¶ 61,076 at P 71 (2003) (rejecting a tariff proposal to permit Northern Natural to shift the financial responsibility of an underlying service agreement to another customer when the original customer files for bankruptcy)).

to unlimited financial risk. LG&E suggests that any uplift should be limited to suppliers in the form of reduced payments because in a voluntary market, suppliers are best positioned to mitigate or avoid credit risk.

### c) Discussion

488. The Commission accepts the Midwest ISO's proposal subject to the modifications directed below. As the Midwest ISO explains, market participants need certainty of being paid or else the market could suffer from illiquidity and market participants could face higher energy prices as entities incorporate the risk of not being paid into their bids, withhold participation in the markets or avoid the markets altogether. Since the Midwest ISO is a non-profit entity that distributes monies from those entities buying services to those that are selling services, if those entities that are buying services do not pay, the Midwest ISO has no means to provide to the selling entities amounts that are owed.

489. The Commission believes that the Midwest ISO's allocation proposal, which is similar to the allocation approved for NYISO's recovery of bad debt losses, is reasonable.[282] However, the Midwest ISO's proposal must be modified to explain the process for a defaulting customer to cure the default after the uplift charge for its bad debt is assessed to other customers.[283] Additionally, the Midwest ISO must state in the TEMT that any amounts later recovered for a particular bad debt loss should be allocated to the customers that paid the uplift charge resulting from that bad debt loss.

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[282] *See* New York Independent System Operator, Inc., 104 FERC ¶ 61,311 (2003) (accepting NYISO's bad debt loss provisions for physical trades). *See also* New York Independent System Operator, Inc., 97 FERC ¶ 61,091 (2001) (accepting NYISO's bad debt loss provisions for virtual trades).

[283] *See* Attachment U to NYISO's OATT, section 4.0 which requires among other things, that a defaulting customer must pay all outstanding and unpaid obligations to cure the default.

490. The Midwest ISO's proposed allocation of the uplift charge pursuant to a formula rate in the TEMT satisfies the notice requirements of the FPA for charging the uplift charge.[284] However, the formula to allocate these costs to market participants contains minor flaws that need to be addressed by the Midwest ISO.[285]

491. In the cases that the Midwest ISO TOs cite to support their contention that the uplift violates commercial law, the Commission required a for-profit company's shareholders to bear the brunt of poor creditworthiness decision by the shareholders' management. In this instance, the Midwest ISO is a non-profit company without shareholders to bear the brunt of poor creditworthiness decisions. Therefore, the cited cases are not applicable.

492. The Commission understands the concerns that this provision may encourage the Midwest ISO to make poor creditworthiness decisions or to not pursue all commercially available avenues to recover the bad debts; however, as mentioned previously, the Commission has accepted uplift charges for bad debt losses for ISOs and RTOs in the Northeast without significant problems.[286] To mitigate the size of the uplift, the Commission requires the Midwest ISO to incorporate into the TEMT a requirement found in PJM's uplift charge provisions that requires a member in default to take all possible measures to mitigate the impact of the default on other members not in default – including, but not limited to, loading its own generation to supply its own load to the maximum extent possible.[287] Nonetheless, if the uplift amounts become sizable, parties

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[284] *See* Public Utilities Commission of the State of California v. FERC, 254 F.3d 250, 254-56 (D.C. Cir. 2001). *See also* Alabama Power Company v. FERC, 993 F.2d 1557, 1567-68 (D.C. Cir. 1993).

[285] For example, in the formula component "% Loss for MPa," the term "Charges" should read "Market Charges" and the component should have a divisor, presumably "MPall (Market Charges + Market Credits)" to create a percentage. In the formula component "Loss Obligation of MPa," the term "Total Loss" should read "Uncollectible Obligation."

[286] The Commission will not address at this time LG&E's concern about a hypothetical situation in which the Commission denies termination to a provider of last resort. LG&E's argument is premature. The Commission has not denied such termination for any provider of last resort. Should the Commission deny such termination, the parties may raise the issue at that time.

[287] *See* PJM Operating Agreement at section 15.4.

may file complaints with the Commission, at which time the Commission may review Midwest ISO creditworthiness provisions and the Midwest ISO actions in implementing those provisions. Additionally, the Commission requires that the Midwest ISO clarify the provision to specify the steps that it will ordinarily take before implementing the uplift charge. The Midwest ISO may take other steps, as necessary, to minimize the bad debts loss.[288]

493. The Commission believes that transmission owners are not similarly situated to sellers in the energy markets; therefore, the provision does not cause inequitable treatment between generators and transmission owners. As discussed above, without the certainty of getting paid, the energy markets could be hindered; therefore, the uplift provision ensures that generators recover their costs. However, a transmission owner experiencing uncollectible accounts attributable to jurisdictional transmission service don't need an uplift to recover their costs. Transmission owners may file with the Commission to recover unpaid debt costs in its transmission cost of service if the transmission owner can demonstrate that the uncollectible accounts are attributable to jurisdictional transmission service.[289]

### *J. Other Tariff Issues*

#### 1. Miscellaneous Module A Issues

494. Section 1.75 of the proposed TEMT defines Distribution Facilities as facilities used to provide Wholesale Distribution Service. The Midwest ISO TOs argue that the proposed definition is overly broad and runs counter to court findings that the Midwest ISO does not possess jurisdiction over the use of distribution facilities.[290] The Commission's jurisdiction over distribution facilities is defined in a recent order

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[288] *See* New York Independent System Operator, Inc., 104 FERC ¶ 61,311 at P 70 (2003).

[289] However, it has been the Commission's experience that most, if not all, of the uncollectible accounts expense is not attributable to jurisdictional transmission service. Transmission owners may seek to recover uncollectible accounts that are not attributable to service jurisdictional to the Commission in their retail rates before state commissions.

[290] *See* Midwest ISO TOs at 43 (citing Detroit Edison Company v. FERC, 334 F.3d 48, 54 (D.C. Cir. 2003)).

addressing a variety of generation interconnect issues and the application of Order Nos. 2003, *et al*. to the Midwest ISO.[291] That order clearly contemplates Commission 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.[292] Accordingly, we direct the Midwest ISO to revise the definition to reflect the Commission's definition.

## 2. Miscellaneous Module B Issues

### a) Penalty for Inadequate Point-to-Point Service

#### *(1) The Midwest ISO's Proposal*

495. In Section 13.7.c, the Midwest ISO proposes to penalize point-to-point transmission customers 200 percent of the Firm Point-To-Point Transmission Service Charge for amounts in excess of reserved capacity at the point of receipt or point of delivery where reserved capacity was exceeded. Similarly, in Section 14.5, the Midwest ISO proposes to penalize non-firm point to point transmission customers 200 percent of the Non-Firm Point-To-Point Transmission Service Charge for amounts in excess of their capacity reservation.

496. The Midwest ISO proposes in Section 37.2 that load-serving entities serving Load in the Real-Time Market that is not in accord with the proposed TEMT and not taking Network Integration Transmission Service will be charged for Network Integration Transmission Service for Load that withdrew Energy during the Operating Day.

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

[292] *See id.*

### *(2) Protests and Comments*

497. AMP-Ohio contends these provisions should be removed and that customers should only be charged the price of transmission, based on previous Commission guidance that the charges are not appropriate.[293] AMP-Ohio also objects to scheduling changes in Section 13.8 that set a 30-minute deadline and the apparent additional penalties in Section 37.2.

### *(3) Discussion*

498. 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 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.

499. 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.

500. The Midwest ISO TOs and Alliant raise concerns regarding the possibility that the Midwest ISO may eliminate point-to-point service. The Midwest ISO TOs add that eliminating point-to-point transmission service would violate the Midwest ISO's fiduciary duty to maximize the Midwest ISO TOs' transmission revenue. However, the TEMT leaves in place the existing point-to-point service while offering significant, market-oriented improvements to regional transmission service throughout the Midwest ISO footprint. The Midwest ISO TOs and Alliant may raise any concerns regarding point-to-point service if the Midwest ISO ever proposes to modify or eliminate such service under its tariff.

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[293] Midwest Independent Transmission System Operator, Inc., 105 FERC ¶ 61,145 at P 70 (2003).

### b) Transmission Pricing

#### *(1) The Midwest ISO's Proposal*

501. Within the Midwest ISO footprint, transmission access charges are assessed on a license-plate basis. Customers pay the embedded costs of the transmission owner in whose zone the energy sinks.

#### *(2) Protests and Comments*

502. Crescent Moon Utilities request that the Commission require, either immediately or after a finite transition period, a TRANSLink-type system-wide high-voltage rate that prices at least all existing Midwest ISO high-voltage facilities that perform the highway transmission function on a postage-stamp basis.[294] Crescent Moon Utilities state that license plate rates are a significant disincentive for Crescent Moon Utilities to join the Midwest ISO with annual cost shifts of approximately $40 million to those customers served exclusively from Crescent Moon Utilities transmission facilities.

503. Cinergy notes that the Midwest ISO is not proposing license plate rate design in this proceeding. Cinergy states that Crescent Moon's request to adopt a high-voltage rate is a collateral attack on earlier Commission order's accepting the license plate rate design.

504. Soyland complains that until May 2, 2004, when Ameren joined Midwest ISO, it used to pay a network transmission rate to Ameren and a separate network transmission rate to Illinois Power. Since Ameren has joined Midwest ISO, Soyland states that its transmission rates have gone up because it is now paying pancaked rates. Soyland pays a Midwest ISO system-wide point-to-point rate and a regional through-and-out rate in addition to Illinois Power's network transmission rate resulting in a rate increase of approximately 250 percent. Soyland recognizes that its situation will likely be remedied once: (1) the Midwest ISO regional through-and-out rate is eliminated on December 1, 2004; and (2) Illinois Power joins the Midwest ISO.

#### *(3) Discussion*

505. Transmission access charges are not the subject of this proceeding. Therefore, the Commission will not direct Midwest ISO to adopt a postage-stamp rate for high-voltage transmission facilities at this time. The Commission notes that the Midwest ISO and PJM are currently developing a long-term solution to inter-RTO pricing in another

[294] Crescent Moon Utilities' concern is shared by other parties including the Minnesota Commission.

proceeding, and that they are scheduled to file their proposal on October 1, 2004, and that proceeding may address some rate issues important to Crescent Moon Utilities and Soyland.[295]

### c) Energy Imbalance Service

#### *(1) The Midwest ISO's Proposal*

506. In the RTO Order, the Commission recognized that individual transmission owners would need to maintain their energy imbalance[296] provisions until the Midwest ISO has one in place.[297] The Midwest ISO suspended the current Schedule 4 of its OATT, Energy Imbalance and Inadvertent Interchange Service, until a further refined and enhanced Schedule 4 can be developed in concert with its stakeholders.[298] The Midwest ISO does not yet have a region-wide operating imbalance provision in place.

507. However, when ITC and METC joined the Midwest ISO, the Midwest ISO filed to include in its OATT several schedules providing for energy imbalance service within the state of Michigan.[299] The Midwest ISO filed the schedules to preserve the benefits of the joint OATT and provide a vehicle for enhancements to be proposed by the transmission-only companies in the state. Despite the Commission's emphasis on the importance of a single OATT for the Midwest ISO region, the Commission accepted the Michigan-specific provisions for energy imbalance for a transition period and required the Midwest ISO to file by January 1, 2003, a single, revised Midwest ISO OATT for service in the Midwest.

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[295] *See* Midwest Independent Transmission System Operator, Inc., *et al.*, 106 FERC ¶ 61,262 (2004).

[296] Energy imbalance service is provided when there is a mismatch between the energy scheduled to be received in the load's control area and the actual hourly energy consumed by the load. *See* Order Nos. 888-A and 888-B.

[297] *See* RTO Order at 62,515.

[298] *See* Midwest Independent Transmission System Operator, Inc., 98 FERC ¶ 61,707 at 61,212, 61,215 (2002).

[299] The Michigan-specific Energy Imbalance schedules include Schedule 4 – Michigan, Schedule 4 – Michigan (METC), Schedule 4B- Michigan (ITC) and Schedule 4C- Michigan (METC) – Generator Imbalance Service.

508. As part of the new Energy Markets, the Midwest ISO proposes to share the functions of balancing with the control area operators in the Midwest ISO region.[300] In performing the balancing function the Midwest ISO, among other things, receives plans and commitments from generator owners within the balancing authority area, provides operational plans and balancing information to the Reliability Authority, and issues dispatch instructions for resources to follow to ensure that energy imbalance is performed in real time. Control area operators are accountable for tasks related to physical, second-to-second balancing of the balancing area and shares with the Midwest ISO the responsibility to direct the generator owners and load-serving entities to take action to ensure balance in real-time. Additionally, generator owners are responsible for providing the Balancing Authority and Transmission Operators with generator ratings, limits, and models; requested amounts of interconnected Operations Services; information related to operating and availability status of units, reports on the status of automatic voltage regulators; report status of automatic voltage regulators to Transmission Operators; and provide requests to interchange authorities to implement interchange transactions.[301]

509. In this proceeding, the Midwest ISO has submitted the TEMT to replace the existing OATT in its entirety, but the TEMT does not have a Schedule 4 for Energy Imbalance. Mr. Volpe explains that:

> In Section 3 of Module A, which addresses Ancillary Services, all references to Energy Imbalance Service under Schedule 4 have been deleted due to the addition of the Real-Time Energy Market in the Tariff. Schedule 4 has been removed because access to a real-time balancing market is now provided through the Real-Time Energy Market as described in Module C.[302]

However, the Midwest ISO has not explained the rationale for maintaining the Michigan-specific Schedule 4s from the Joint OATT.

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[300] Midwest ISO states that there are multiple types of control areas in the Midwest ISO region which is different from other ISOs that are certified control area operators.

[301] *See* Exhibit No. MISO-7 at 23.

[302] *See* Exhibit No. MISO-9 at 10, line 14-18.

### *(2) Protests and Comments*

510. Detroit Edison recommends that "Schedule 4 – Michigan" should be removed from the TEMT and that Schedule 4 of Detroit Edison's Ancillary Service Tariff (AST) should be removed as obsolete. Under "Schedule 4 – Michigan," the Midwest ISO manages differences between the scheduled and actual delivery of energy to load located in Michigan. Under Schedule 4 of the AST Detroit Edison provides energy imbalance as part of its stand-alone tariff. Detroit Edison claims that both of these schedules are unnecessary because Midwest ISO will dispatch resources to simultaneously balance injection and withdrawals as part of Midwest ISO's real-time LMP energy market and the Midwest ISO will settle all purchases and sales in real-time market and assess penalties for uninstructed deviations.[303] Detroit Edison requests that the Commission find that Detroit Edison no longer has an obligation to provide energy imbalance service because all imbalances will be corrected through the operation of the Real-Time Market.

511. Midwest SATCs state that the Midwest ISO should be required to be the provider of last resort for ancillary services including energy imbalance with such responsibilities to be set forth in the tariff.[304] Midwest SATCs explain that while the Midwest ISO has historically included several Schedule 4s (Schedule 4, 4-Michigan, 4A, 4B and 4C) in its tariff, it has not provided an energy imbalance service across its footprint. Instead, the Midwest ISO's generally applicable energy imbalance service has to date been indefinitely suspended, with transmission owners or control areas generally providing any necessary imbalance services directly to their customers. Midwest SATCs ask the Commission to require the Midwest ISO to amend its tariff in this proceeding to include a schedule for energy imbalance service.[305] They argue that the implementation of the markets within the Midwest ISO region does not eliminate the need for this service. In fact, they point out that both PJM and ISO-NE have tariff schedules: (1) requiring

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[303] Consumers does not contest the existence of the Michigan-specific energy imbalance schedules. It merely notes certain typographical errors in the Michigan-specific schedules.

[304] *See* Midwest SATCs at 27 n.47 (citing Order No. 2000 at 31,378 (RTOs "must serve as a provider of last resort for all ancillary services acquiring ancillary services from third parties").

[305] The Midwest ISO does not include in the proposed TEMT generally-applicable and currently suspended Schedule 4, but it does propose to retain the existing sub-schedules (Schedule 4-Michigan, 4A, 4B and 4C). Thus, Midwest SATCs state that the Midwest ISO is not currently proposing to provide an energy imbalance service across its entire footprint.

transmission customers to procure or self-provide energy imbalance service; and (2) explaining how such services may be procured through energy markets. Midwest SATCs believe that the Midwest ISO should be required to follow the same approach with such schedule being available throughout the Midwest ISO region.

512. Wolverine states that it will be double-charged for energy imbalance since the Midwest ISO proposes to apply its Real-Time Markets to Midwest ISO OATT customers in Michigan and to continue to apply an energy imbalance service charge to customers located within the Michigan Electric Transmission Company (METC), Schedule 4A, and International Transmission System pricing zones, Schedule 4B, the two Midwest ISO pricing zones within Michigan. Wolverine states that real-time energy markets, based on market prices, are designed to replace the cost and penalty based Schedule 4 energy imbalance charges. Wolverine states that Module C of the TEMT provides for the real-time energy markets and it applies throughout the Midwest ISO including Michigan. Wolverine explains that Midwest ISO should eliminate the Michigan-specific schedules based on Mr. Volpe's testimony.[306]

513. Strategic states that the Michigan-specific energy imbalance schedules conflict with Section 40.3 of the TEMT and Mr. McNamara's testimony. Section 40.3 of the TEMT states that:

> The Transmission Provider will provide timely Settlement of purchases and sales of Energy in the Real-Time Energy Market and will assess penalties for deviations from Dispatch Instructions. Settlement of the Real-Time Energy Market will be conducted on an Hourly basis as described below. Real-Time Settlement for injections and withdrawals is based on Hourly Ex Post LMPs calculated using the integrated Ex Post LMP and reported MWh values. Settlement is also performed on quantity deviations from Day-Ahead Schedules.[307]

514. Mr. McNamara states in his direct testimony that:

> Load Serving Entities ("LSEs") can supplement their contracts with purchases from the Midwest ISO Day-Ahead and Real-Time Markets, and use the real-time balancing market to purchase or sell any imbalances

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[306] Given Mr. Volpe's testimony, Municipal Participants agree that the Michigan-specific schedules should be eliminated as inconsistent with real-time market structure.

[307] Module C, Section 40.3, Original Sheet No. 574.

> between their contract amounts and the amounts actually supplied or consumed. Open access to the Midwest ISO spot markets will thus relieve LSEs and their suppliers of any requirement to maintain balanced schedules or to engage in expensive load following on their own (although parties will be free to match their supplies and obligations as closely as they want). With imbalance energy priced at market-clearing LMPs, parties will no longer be faced with the imbalance penalty charges they sometimes face today.[308]

515. NIPSCO states that the proposed TEMT provides that the Real-Time Market will clear every five minutes, but that imbalance energy charges should not be imposed in five-minute increments. NIPSCO states that its load varies widely during an hour and that industrial load, in particular, is difficult to forecast. It believes that imposing an intra-hourly balancing charge will far outweigh any operational or reliability benefits gained. NIPSCO requests the Commission require the Midwest ISO to resolve imbalances on an hourly basis at the prices established in the Real-Time Market.

***(3) Discussion***

516. The Commission required the Midwest ISO to file a proposal for a more efficient real-time imbalance energy market that meets the requirements of Order No. 2000 at the time it granted the Midwest ISO RTO status.[309] The Midwest ISO's proposed real-time energy market provides a real-time balancing market that satisfies the requirements of Order No. 2000. While control area operators and generation owners work cooperatively with the Midwest ISO to balance the system, ultimately the Midwest ISO is the entity that provides the Energy Imbalance Service and charges market participants for the imbalances. The Commission determined in Order No. 888 that energy imbalance schedules are required to be included in the OATT.[310] The Commission has approved for other ISOs and RTOs tariff schedules explaining the terms, conditions and rates for Energy Imbalance which must be provided by the Transmission Provider.[311] The Midwest ISO has not provided any rationale for treating it differently from other ISOs

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[308] McNamara testimony at 40.

[309] *See* RTO Order at 62,522.

[310] *See* Order No. 888 at 31,715.

[311] Schedule 4 of the PJM, NYISO and NEPOOL tariffs set forth the rates, terms and conditions for the energy imbalance service.

and RTOs that have energy imbalance schedules in their OATTs.[312] Accordingly, the Midwest ISO must file a Schedule 4 to its TEMT to set forth the terms, conditions and rates for energy imbalance service it provides region-wide in order for the TEMT to be complete and compliant with Order No. 888.[313] The Commission encourages the Midwest ISO to file the Schedule 4 within 60 days of the date of this order to permit sufficient time for Commission review prior to the commencement of the Energy Markets.

517. Moreover, the absence of an energy imbalance schedule would leave undefined the terms of service. For example, Section 40.3 of the TEMT states that settlement in the Real-Time Market will be done on an hourly basis, but because Midwest ISO does not have a schedule for energy imbalance service, NIPSCO believes that imbalances must be resolved on an intra-hourly basis. The Commission's requirement to file an energy imbalance service schedule will eliminate any uncertainty by declaring that imbalances are to be resolved over a single hour. This is the same practice other ISOs and RTOs use.[314]

518. Since companies in Michigan will no longer need to charge for energy imbalance service when the Midwest ISO begins its Real-Time Energy Market, the Commission rejects the Midwest ISO's proposed Michigan-specific Schedule 4s and requires the Midwest ISO make a compliance filing within 30 days of the date of this order to eliminate the Michigan-specific Schedule 4s.[315] Moreover, the Commission set a

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[312] The Commission notes that other ISO/RTOs do not have to share the balancing authority function as the Midwest ISO does. Nonetheless, such sharing of the function does not change the fact that the Midwest ISO is the entity that will be charging the market participants for imbalances and the Midwest ISO is required to have a schedule in its OATT setting forth the rates, terms and conditions of service.

[313] The Energy Imbalance schedule submitted in the compliance filing should, similarly to PJM's and NYISO's Schedule 4, explain when the service is provided and require the Midwest ISO to offer this service to serve load in the Midwest ISO's footprint, and the Transmission Customer must purchase the service from the Midwest ISO. The Schedule 4 should also provide the rates for the service (presumably the hourly LMP).

[314] Schedule 4 of NYISO, NEPOOL and PJM clearly state that the imbalance is calculated over a single hour.

[315] If Detroit Edison wants Schedule 4 of its AST eliminated it must file a notice of cancellation with the Commission.

deadline of January 1, 2003 for eliminating the Michigan-specific schedules so that the Midwest ISO would have one energy imbalance provision apply region-wide.

### 3. Miscellaneous Module C Issues

#### a) Day-Ahead Market Procedures

##### *(1) The Midwest ISO's Proposal*

519. The Midwest ISO proposes to operate a Day-Ahead Market in which energy bids and offers, bilateral schedules and self-schedules are submitted and optimized to produce a Day-Ahead Schedule. The Midwest ISO will also calculate LMPs and transmission usage charges associated with this Day-Ahead Schedule. The Day-Ahead submission deadlines for market participants are: 0900 EST the Day before operating day for Bids/Offers, Self Scheduled Resources, and External Bilateral Schedules. Internal Bilateral Schedules may be submitted until 1200 EST the Day after the Operating Day. The control area operators must submit the next day's Load Forecasts to the Midwest ISO by 0900 EST. The Midwest ISO Issues the next day's Load Forecast for the region and Day-Ahead Schedules for the next operating day by 1500 EST. All transactions in the Day-Ahead Energy market are financially binding.

##### *(2) Protests and Comments*

520. Numerous intervenors protest the 0900 EST deadline for next-day bids, offers and schedules.[316] The primary reasons cited are that the early submission is not coordinated with PJM's day-ahead market deadline, thus creating a seams issue, that it will disadvantage Market Participants that also participate in the short-term bilateral markets, that loads will have to submit next-day forecasts before they are ready (or know what the control area load forecast is) and that it is earlier than the gas nomination deadline.

521. In its Answer, the Midwest ISO notes that it has begun to implement enhancements to its Market System Software so as to move to an 1100 EST deadline as soon as practicable. It cautions that it cannot guarantee that the deadline can be changed until the enhancements have been tested. It notes that it will still be required to keep the posting of the Day-Ahead Schedule at 1500 EST prior to the operating day to allow for the long lead times for some generation.

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[316] *See* AMP-Ohio at 16-17; Consumers at 6-7; IMEA at 7-8; Detroit Edison at 43-44; Dominion at 17-19; Duke at 7-8; Dynegy at 12-13; Edison Mission at 5; EPSA at 20-21; FirstEnergy at 6; MidAmerican at 13; Municipal Participants at 24-25; Reliant at 8-9; Strategic Energy, LLC at 8; TVA at 7-8.

#### *(3) Discussion*

522. Given the delay in the implementation of the Day 2 market, we see no reason why the trading deadline of 1100 EST for the Day-Ahead Market should not be achieved. We will request that the Midwest ISO file an update on progress toward this goal no later than 90 days prior to the implementation of the Day 2 market.

### b) Reliability Assessment Commitment Procedure

#### *(1) The Midwest ISO's Proposal*

523. Section 40.1 of the TEMT provides details on the Midwest ISO's proposed RAC process, the mechanism that assures the transmission provider will have sufficient resources available to serve forecasted load reliably in real-time. A RAC process is necessary because forecasted load may exceed load bid into and cleared in the Day-Ahead market. The RAC process allows the Midwest ISO to commit additional capacity required to serve higher forecasted real-time load. The process principally relies on Day-Ahead offers from Network Resources not selected in the Day-Ahead Energy Market. Network Resources are required to participate in the RAC process, although all generation resources may participate. An SCUC algorithm will be used to commit additional resources considering only Start-Up, No-Load Offers and Offers at minimum Load. Resources committed through the RAC process must submit offers to the Real-Time Market and will be dispatched on an economic basis.

#### *(2) Protests and Comments*

524. AMP-Ohio argues that entities that self-schedule resources could be exposed to additional, unjustified costs through exposure to RAC charges. It notes that a load-serving entity with dynamically scheduled resources could meet its extra load needs in real time.

525. Consumers recommends that the SCUC used for the RAC have the ability to evaluate a scenario that includes the loading cost of a unit in addition to its start-up and no-load costs. Consumers argues that this could lead to a more cost-effective RAC.

526. Dynegy argues that several RAC procedures need to be clarified or modified. Dynegy suggests that the RAC objective function should be to solve for 100 percent of the load forecast plus reserve margin. Dynegy states that the Intra-Day RAC process appears to use bids and offers from the previous day-ahead RAC. This needs to be clarified. Dynegy states that it is unclear how the Midwest ISO will compensate units dispatched in the Intra-Day RAC when fuel prices change over the time period. Dynegy states that it is unclear how penalties for generators that do not bid into the RAC are calculated and what the amount is. Further, it is not clear what financial obligations exist for a generator that is committed in the RAC but trips off-line in real-time. Do such

generators buy back power in real-time? Do they owe back start-up and minimum load payments for the whole day or just the hours off-line? Dynegy claims that the RAC process includes the offer requirements associated with installed capacity resources in PJM and NYISO but without the offsetting capacity payments.

527. LG&E states that it is not clear what the Midwest ISO's role is in acquiring capacity to serve load in relation to a load-serving entity's procurement to meet load. LG&E has concerns about the Midwest ISO's authority to commit resources up to six days before the start of the DAM. LG&E states that it is not clear how the RAC process improves the operations of the various control areas under NERC Operating Policy 9A, which requires reliable operations of the bulk power system. LG&E seeks further assurances that the RAC process is designed to enhance reliability and not to increase the liquidity of the RTM. LG&E requests that it and other similar entities should receive rebuttable presumptions that they will adequately self-provide load following capability. LG&E requests that the Commission reject the RAC provisions or provide an opt-out.

***(3) Discussion***

528. We will approve the RAC process as filed. All eastern markets with designs similar to that proposed by the Midwest ISO rely on procedures similar to the RAC process to assure real-time reliability. The proposed RAC process allows the Midwest ISO to commit additional resources when needed to meet load forecasts. These resources then submit offers to the real-time market, are dispatched when economic, and paid market clearing prices with assurances for start-up and no-load costs. Entities relying on self-scheduling, such as AMP-Ohio, are not disadvantaged in any way by RAC procedures. All may offer their own resources into the RAC to ensure that any costs they may incur are offset by equivalent RAC payments. Similarly, we reject LG&E's concerns that an opt-out provision is needed or additional assurances are required to guarantee that the RAC process will not be used to increase liquidity of the RTM. The RAC process in no way impairs LG&E's ability to use its resources to serve its load or exposes it to costs that it would not otherwise incur. We disagree with Dynegy that the RAC process is not sufficiently detailed in the TEMT. We further find that the requirement for Network Resources to participate in the RAC process merely precludes withholding capacity from the market. Physical withholding of economic resources is an exercise of market power and the requirement to participate in the RAC process further protects customers against the exercise of market power.

### c) Penalties for Uninstructed Deviations

#### *(1) The Midwest ISO's Proposal*

529. The Midwest ISO proposes penalties for generators that deviate excessively from their dispatch instructions in real time. Uninstructed deviation penalties (UDPs) will be levied on deviations that exceed a tolerance band of plus or minus 10 percent of the hourly average dispatch instruction. Transactions within the 10 percent threshold are settled without penalty. The 10 percent tolerance band is adjusted for the megawatts of regulation capacity that the resource provides. It has a minimum threshold of 5 megawatts and a maximum of 25 megawatts.

530. The penalty structure for under-generation is a penalty of the product of 40 percent of the hourly *ex post* LMP, for the applicable hour, and the positive difference between the tolerance band lower limit and the actual injection at the node. For over-generation, generators will be paid the product of 40 percent of the hourly *ex post* LMP, for the applicable hour at that node, and the positive difference between the actual injection at the node and the tolerance band upper limit.[317]

531. Certain classes of market participants, such as intermittent resources and demand response resources, would be exempt from UDPs because of their dispatch characteristics. The Midwest ISO will distribute any excess penalty revenues that it collects through the uninstructed deviation charges to market participants' loads, based on their load ratio share for which they bid or submit a bilateral transaction schedule.

#### *(2) Protests and Comments*

532. Consumers seeks clarification that a generator experiencing a forced outage is exempt from the UDPs and imbalance charges in Section 40.3.4.c.ii. It finds the language in Section 40.3.4.e similarly unclear regarding the method for distributing any

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[317] Dr. McNamara's testimony gives examples of over- and under-generation with penalties. Over Generation Example (we note this appears to conflict with Original Sheet No. 585): Generator Base Point set to 100MW, with no regulation, and they actually generate 113MW. Compensated at 100 percent of LMP for the first 110MW (100MW dispatch instruction + 10MW safe harbor band) and 60 percent of LMP for the remaining 3MW (40 percent penalty for over generation).

Under Generation Example: Base Point 100MW, no regulation, actual output 88MW. Compensated 100 percent of LMP for 86MW (100MW dispatch instruction – 10MW safe harbor band = 90MW) and 60 percent of LMP for 2MW (90MW – 88MW = 2MW).

excess charges to market participants' load based on the load ratio share for which they bid. Dynegy urges the Commission to reject the penalties section because it deviates from the UDP structure the Congestion Management Working Group approved. EPSA objects to the penalties as being unnecessary, burdensome, possibly duplicative, and not reflective of the natural market forces associated with LMP nodal pricing. PSEG states that the Midwest ISO should remove the language on UDPs because it has not justified that any incentive to follow dispatch instructions is needed beyond what is inherent in the pricing signals of real-time LMPs. Reliant also argues that LMPs are sufficient incentive for resources to follow their dispatch instructions, but if the penalties are retained, Reliant seeks further clarity from the Midwest ISO on the treatment of units that "trip" during an hour where they have received a dispatch instruction.

***(3) Discussion***

533. We will conditionally accept the UDP proposal in Section 40.3.4, subject to the Midwest ISO's compliance with the directives below. We are not convinced by the commenters' arguments that LMP provides sufficient incentive to follow dispatch instructions at all times. Although market forces provide an incentive to follow dispatch instructions most of the time, we continue to believe that a penalty system will aid in the Midwest ISO's ability to maintain system reliability in real time by dissuading generators from excessively deviating from their dispatch instructions.[318] However, we agree with Reliant that it is unclear from the present tariff language how the Midwest ISO will treat generators that trip after receiving dispatch instructions. Therefore, we direct the Midwest ISO to clarify the process it intends to use for generators that trip after receiving dispatch instructions, particularly if they propose exemptions from deviation penalties. Regarding Consumers' concerns about the distribution of excess charges based on load ratio share, we refer them to the section of this order that addresses the Generator Shortfall Uplift Charge.

534. The Midwest ISO is directed to revise Section 40.3.4.c.ii., in which it outlines the penalties for injections greater than the tolerance band. This Section states that for injections greater than the dispatch instruction, and beyond the tolerance band upper limit, the Market Participant will be penalized by being credited only the product of 40 percent of the hourly *ex post* LMP at the applicable node and the positive difference between actual injections at that node and the tolerance band upper limit. This appears to conflict with the examples given in Dr. McNamara's testimony and would create an unbalanced penalty structure, in that under-generation will be penalized at 40 percent of

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[318] *See* TEMT Order at P 98 (identifying UDPs as a "support mechanism" to buttress LMP's incentive not to deviate from dispatch instructions).

LMP, but over-generation will only be compensated at 40 percent of LMP, or in other words, a 60 percent penalty. The Midwest ISO is directed to revise Original Sheet No. 585 to state that generators will be credited the product of 60 percent of LMP for injections beyond the tolerance band upper limit so that the penalty for both over- and under-generation is 40 percent of the applicable LMP.

535. In addition, the procedures to certify intermittent resources have not been developed. We noted in the TEMT Order that the future tariff filing must include language on the procedures and criteria for certifying intermittent resources.[319] Those procedures need to be completed and filed with the Commission prior to market startup through a compliance filing. In addition, we require the Midwest ISO to file more detail on the resources that are eligible to be exempt from UDPs, such as emergency conditions, resources in test mode, resources in start-up or shut-down mode, and run-of-the-river hydro units. We direct the Midwest ISO to develop procedures to exempt intermittent resources and file those procedures with the Commission prior to market start-up.

536. For the foregoing reasons, we direct the Midwest ISO to modify the UDP language, as directed above, in a compliance filing within 60 days of the issuance of this order.

### d) Confidentiality Provisions

#### *(1) The Midwest ISO's Proposal*

537. Module D catalogs the data that the Midwest ISO will collect and to which the IMM will have access. Further, Module D identifies the data that the IMM may request from market participants, and addresses the Market Monitor's confidentiality requirements. Separately, in Module C the Midwest ISO proposes a data confidentiality policy to govern its own disclosure of confidential data to market participants, the Commission, and the states.

538. Module D provides that the IMM will have access to the following data collected by the Midwest ISO: (1) hourly schedules, bids and offers, actual output of resources, imports and exports from the Midwest ISO region; (2) reserved and scheduled transmission service; (3) transmission limits; (4) hourly flows over monitored transmission facilities; (5) dispatch of generation for energy, regulation, and frequency or other operational orders; (6) re-dispatch of generation; (7) logs of transmission service requests; (8) logs of generator interconnection requests; (9) generation and transmission

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[319] *See id.* at P 99.

outage data; (10) customer complaint data; and (11) any other information required by the Midwest ISO under its tariff, operating agreements, for regional reliability organizations or government agencies.

539. Module D further provides that if the IMM determines that it needs additional data or other information to monitor the market, it may ask those: (1) having; (2) having access to; or (3) having the ability to generate or produce such data or other information to provide it to the IMM. The IMM may request the following: (1) production costs; (2) opportunity costs; (3) generating logs; (4) transmission logs; and (5) bidding agreements. A party that receives such a data request must provide the information so long as the data is reasonably necessary for the monitoring plan, not readily available from some other source that is more convenient, less burdensome and less expensive, and not subject to legal privilege. No party that is the subject of a data request will be required to produce summaries, analyses, or reports of the data if such summaries don't exist at the time of the data request.

540. The Midwest ISO proposes tariff provisions in Module C that will govern its own handling of confidential data.[320] The Midwest ISO will not disclose confidential information, except in four circumstances. First, disclosure to NERC or Regional Reliability Councils is permissible if certain conditions are satisfied. Second, disclosure to a third party is permissible if the affected entity authorizes the release in writing, and disclosure is limited to the terms of the authorization. Third, the Midwest ISO may disclose confidential data if required by law or in the course of an administrative or judicial proceeding other than a Commission proceeding or investigation. Fourth, the Midwest ISO may use information that it already had, or that it was able to acquire, without being subject to confidentiality restrictions. The Midwest ISO also proposes to provide confidential information to the Commission and its staff upon request, "during the course of an investigation or otherwise."[321] The Midwest ISO will request that information it holds as confidential also be treated as confidential and non-public by the Commission and its staff under 18 C.F.R. § 388.112.

541. The Midwest ISO proposes to provide confidential information to state commissions, state agencies that share regulatory responsibilities with the state commissions, or any organization formed by such state regulatory commissions (*e.g.*, OMS), if those entities request confidential information in the course of an investigation or are otherwise acting in fulfillment of a statutory duty. In disclosing the

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[320] *See* Module C, Section 39.9, Original Sheet Nos. 455-69.

[321] Module C, Section 38.9.3, Original Sheet No. 463.

information, the Midwest ISO must request that the requesting entity treat the information as confidential and non-public.

542. The Midwest ISO proposes that if a state entity or OMS seeks confidential information from the IMM, the IMM will be required to provide the information. If the affected Market Participant has identified the information sought as "commercially sensitive," then the requesting party must identify its authority for making the request and the mechanism it will use to keep the information confidential and non-public. State entities and OMS may always participate in meetings and conferences with the IMM where confidential information is discussed.

543. Finally, the Midwest ISO proposes that market participants will have no right to receive or review information provided to the Midwest ISO that has been designated confidential pursuant to procedures in the Business Practice Manuals.

### *(2) Protests and Comments*

544. Wisconsin Retail says that there should be more transparent availability of key data such as bid information and generator status. Midwest TDUs believe that transparency is crucial at the onset of the market and that concerns about possible collusion should not stop release of non-confidential data or its release with a delay of three to six months. They say that the current asymmetry of information access favors sellers over buyers and thus encourages the exercise of market power. Those with knowledge of generation or transmission outages will be able to game the system, and will be helped by others not seeing the data. As a result, they say that real-time generator status information, "which is already available from costly private sources," should be made public. They also urge that bid and offer information, including for FTR bids, be released no more than one week after the Real-Time Market clears.

545. The Midwest TDUs object to the Midwest ISO's statement in the Illustrative Allocation of FTRs that information regarding CFTRs that will be nominated or received by a given Market Participant is confidential because it is commercially sensitive. They state that FTR nominations and allocations are rates, or affect rates, for jurisdictional service under FPA section 205(c), and that the details, including nominations, that would permit market participants to gauge the allocations' accuracy must be available. The Midwest TDUs also argue that the process for calculating Reference Levels under Section 64.1.2 gives the IMM and sellers discretion. They argue that the Commission must allow market participants other than the affected generator input into this rate-setting mechanism.

546. In contrast, the Midwest ISO TOs state that the IMM's authority to demand data is overly broad, both with respect to what it can demand and from whom it can seek information. Indeed, the Midwest ISO TOs say that these provisions should have the

basic protections built into discovery at the Commission or under the Federal Rules,[322] which include protections against performing studies and excessive recovery. The IMM should have the obligation, when challenged to justify its request. Control area operators and their loads should not bear the costs of any data request upon them, especially when they are simply a source of information. WEPCO says that the specification of data which the IMM may request should not include the phrase "not be limited to" because it is overly broad and implies the IMM may require the transmission provider to provide the data at any cost. They also say that the list of data in Section 61.1.a that the IMM may request from market participants is overly broad. AMP-Ohio says that entities should be allowed to object to the provision of information under Section 61 to which they believe the IMM should not have access without the need to be in violation of Section 54.2.2.

547. Reliant notes that Section 38.9 refers to the use of a non-disclosure agreement to protect confidential information, but the TEMT and its attachments do not include the document. Commenters including Reliant and EPSA urge the Commission to order the Midwest ISO to create such a document; Reliant adds that the document should be non-negotiable. It suggests that stakeholders be included in this process. Detroit Edison also requests stakeholder review of the proposed provisions, and urges that state commissions be included in the review process.

548. Several commenters express concerns about the Midwest ISO's proposal for disclosing confidential information to state regulatory commissions or state agencies. Detroit Edison argues that the Midwest ISO's proposal is overly broad, due to the number of agencies that may request the information and the lack of specific information that may be sought through a request. EPSA states that concerns about potentially overriding state legislation, the possibility that state utility commissions may not be able to deny other third parties access to the information, and states' emerging interest in involving themselves in interstate RTO activities reinforce the need to more clearly define whether all requestors, including state commissions, have a legitimate need for commercially sensitive information. It specifically suggests refining the concept of an "Authorized Requestor" in Section 38.9.4.

549. Detroit Edison points out that nothing indicates how state entities will be required to protect confidential information and that consequently, market participants will have to monitor state agencies that obtain access to confidential data. Detroit Edison states that the TEMT does not propose: (1) a specific method for destruction or return of confidential information; or (2) remedies to a market participant if the provision is

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[322] The Midwest ISO TOs do not specifically identify the "Federal Rules" to which they refer.

breached. It notes that the Commission recently rejected a proposal to allow enhanced disclosure to oversight and enforcement agencies on the ground that that provision was overly broad and that there were not adequate safeguards to protect the information.[323]

550. Cinergy argues that the proposed treatment of Confidential Information provided to the Midwest ISO and the IMM provides insufficient protection and exposes market participants to unnecessary risk. Cinergy suggests 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 with jurisdiction to compel release of the information.

551. Duke and Dynegy observe that Dr. McNamara's testimony indicates that the Midwest ISO intends to limit the disclosure of market information to OMS by limiting OMS's access to data more than six months old and prohibiting OMS from copying real-time data. They state, however, that the TEMT does not contain language establishing these limitations and that it is essential that the Midwest ISO provide explicit clarifying language delineating the limitations on such disclosure.

552. Duke and Dynegy also state that Section 38.9.2 provides that market participants must be notified prior to the disclosure of their confidential information to third parties other than the Commission, but that Section 38.9.4 does not contain a parallel provision to provide notice to parties before data is disclosed to state regulatory commissions. Duke and Dynegy request that the Midwest ISO incorporate these mechanisms in Section 38.9.4.

553. The Midwest ISO TOs argue that Section 54.3, which applies to the IMM, should be modified to provide a notice provision allowing the entity that supplied certain data with a sufficient number of days to block production before the IMM turns over data to interested government agencies. The Midwest ISO TOs add that there should be a provision preventing governmental agencies from releasing information unless the Midwest ISO or the IMM is satisfied that under federal or state law, the information would remain confidential (for example, exempt from disclosure under the Freedom of Information Act).

554. Cinergy argues that the Midwest ISO and the IMM should notify affected owners of information as soon as practicable of any legal proceeding seeking access to Confidential Information, so that the owner can decide whether to intervene or seek a

[323] Detroit Edison at 28-29 (citing California Independent System Operator Corporation, 106 FERC ¶ 61,179 at P 164 (2004)).

protective order in that proceeding. Cinergy generally objects to Sections 38.9.4 and 54.3 of the TEMT. Cinergy argues that state laws and administrative procedures allow the state commissions certain powers to obtain Confidential Information or undertake legal proceedings to do so, and that absent these limits states commissions could access myriad kinds of sensitive information. Cinergy urges the Commission to reject these Sections and apply Section 38.9.2 to state commissions as it does other third parties.

555. OMS asserts that the Midwest ISO's proposal for state access to confidential data "categorically satisfies" OMS's desire to have access that is comparable to the Commission's. OMS and the Illinois Commission[324] argue, however, that the Commission should require the Midwest ISO to make certain changes to the TEMT. First, OMS and the Illinois Commission advocate clarifying the terms "Commercially Sensitive" and "Confidential Information." They observe that Sections 54.3(c) and (d) refer to the treatment of a request for information that a Market Participant or the IMM has designated "commercially sensitive," yet the TEMT does not define this term. OMS and the Illinois Commission also note that Sections 1.37 and 54.4 provide different definitions of Confidential Information. To resolve the discrepancy, they suggest changing the term "commercially sensitive" in Sections 54.3 (c) and (d) to "competitively sensitive" or adding the term "commercially sensitive" to the list of types of confidential information in Section 54.4. OMS and the Illinois Commission also argue that the definition of the term "confidential information" – anything designated confidential by the entity supplying the information – is too open-ended. They recommend that the Midwest ISO develop a process so that the designation of information as confidential may be challenged.

556. Second, OMS and the Illinois Commission note that Section 38.9.4(a) requires an Authorized Requestor to demonstrate the ability to keep confidential any confidential information that the Midwest ISO discloses to it, and that OMS itself may not disclose the Midwest ISO's confidential information to third parties that are not Authorized Requestors. OMS and the Illinois Commission argue that Authorized Requestors may share among themselves confidential information that the Midwest ISO discloses to them, but that the parallel provision does not so clearly permit Authorized Requestors to share confidential information that the IMM provides. They argue that the Commission should require the Midwest ISO to correct this discrepancy by inserting the words "who are not Authorized Requestors" into the language of Sections 54.3(c) and (d).

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[324] The Illinois Commission, which provided its feedback in reply comments, does not agree with OMS that the Midwest ISO's confidentiality proposal is adequate to allow states to obtain access to confidential information. It echoes OMS's requests for certain editorial changes to the TEMT, however.

#### *(3) Discussion*

557. We will accept portions of the Midwest ISO's confidentiality proposal as an interim measure, subject to the modifications discussed below. The Midwest ISO will be required to file the modifications within 60 days of the date of this order. The Midwest ISO is also directed to make corresponding changes to Attachment Z.[325] We note that there are many distinctions between the Midwest ISO's proposal and PJM's recent revisions to its confidentiality rules, which the Commission accepted on June 28, 2004, and that the Midwest ISO's proposal may provide greater access to data than PJM's does.[326] 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. We therefore direct the Midwest ISO to work with its stakeholders, and with PJM if it desires, to more closely align its confidentiality proposal with PJM's, and to file a revised proposal. For the reasons described below, we will reject the Midwest ISO's proposals to share information with state commissions. As part of the process of developing a revised confidentiality process that is more closely aligned with PJM's, the Midwest ISO should work with stakeholders and state commissions to develop a consensus proposal governing disclosure of data to state regulatory agencies.

558. The Commission does not share parties' concerns that data requests from the IMM may be too broad, and thus too costly. The TEMT provides in Section 54.2.2.b that the categories of data that may be routinely requested are limited to data that can be routinely provided without undue burden or expense. Section 54.2.2.b also provides that no party will be required to produce any summaries, analyses, or reports of data that have not already been produced. As such, the Commission does not believe that the data requests will be unduly burdensome for buyers, sellers, or other parties such as control area operators.

559. We agree with Wisconsin Retail and the Midwest TDUs that transparency is an important feature of market design. Accordingly, we agree with these parties 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

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[325] *See* Attachment Z, Non-Disclosure and Confidentiality Agreement, Original Sheet Nos. 1752-1780.

[326] *See* PJM Interconnection, L.L.C., 107 FERC ¶ 61,322 (2004) (PJM Confidentiality Order).

six-month delay and should have participants names' masked, as they are in NYISO.[327] The Midwest ISO and the IMM should not be required to provide generator outage data to market participants. There is no such requirement in any of the other Eastern ISO markets, and we do not believe it to be necessary in this case either.

560. The Commission also takes seriously other commenters' concerns that there should be adequate safeguards for market data, particularly market data that is confidential or commercially sensitive. We will require the Midwest ISO to make a number of amendments to its confidentiality proposal to improve the safeguards for confidential information in its possession. At the outset, we will require that the Midwest ISO synchronize its proposal for its own data disclosure, and for the IMM's data disclosure. It should not be possible for requestors to obtain data from either the Midwest ISO or the IMM that they cannot obtain from the other.

561. We will reject Sections 38.9.4 and 54.3, pertaining to the Midwest ISO's and the IMM's authority to share information with state regulatory commissions and other Authorized Requestors. 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. We therefore instruct the Midwest ISO to work with its stakeholders, and with PJM if it desires, to develop a revised proposal. The revised proposal should include the type of non-disclosure agreement recently approved for PJM. Such an agreement will harmonize Authorized Requestors' individual obligations to protect data.

562. The revised proposal should delete the Midwest ISO's proposal to permit Authorized Requestors to disclose Confidential Information to other Authorized Requestors. As Detroit Edison and EPSA point out, permitting Authorized Requestors to exchange confidential data severely limits the Midwest ISO's ability to assess whether a party that receives the data has a legitimate need for it, and whether the Authorized Requestor can keep the data confidential under their individual statutory and regulatory authority.[328] The Midwest ISO and stakeholders also should consider Cinergy, Duke and

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[327] *See* NYISO, 6 Month Bid Data Release, *available at* http://mis.nyiso.com/public/postings/NYISO%206%20Month%20Bid%20Data%20Release%20Description.pdf.

[328] The Commission recently rejected a protestor's similar proposal in conjunction with PJM's new information-sharing policy. The Commission noted that allowing

(continued)

Dynegy's argument that market participants should be notified before the Midwest ISO or the IMM divulges Confidential Information to state regulatory commissions.

563. We also agree with OMS and the Illinois Commission that the Midwest ISO should amend the definitions in its tariff to make them consistent with one another. Section 1.37 of the TEMT states that Confidential Information is:

> Any confidential, proprietary, or commercially sensitive information of a plan, specification, patter[n], procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Transmission Customer, Market Participant, or other user, which is designated as confidential by the entity supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise, that is received by the Transmission Provider and is not disclosed except under the terms of a Confidential Information policy.[329]

This definition is somewhat broader than the definition stated in Section 54.4, which defines Confidential Information as:

> [D]ata or information that is proprietary, commercially valuable or competitively sensitive, or is a trade secret and that has been designated as confidential by a Market Participant, provided that such information is not available from public sources, or is not otherwise subject to disclosure under any tariff or agreement administered by the [Midwest ISO].[330]

OMS and the Illinois Commission suggest changing the term "commercially sensitive" to "competitively sensitive" in Sections 54.3.c and .d, or adding the term "commercially sensitive" to the list of types of confidential information listed in Section 54.4 will resolve the differences between the types of information.

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requestors to share data without PJM's knowledge would make it much more difficult for PJM to keep track of who has what data. *See* PJM Confidentiality Order at P 35-37.

[329] Module A, Section 1.27, Original Sheet No. 56.

[330] Module D, Section 54.4, Original Sheet No. 731.

564. We agree that a change is needed, and will direct the Midwest ISO to submit proposed tariff revisions that will harmonize Sections 1.37 and 54.4. The Midwest ISO should, however, make changes in addition to those OMS and the Illinois Commission suggest. We believe that the Midwest ISO and its customers will be better served if there is a single definition of Confidential Information in the TEMT. We know of no reason why Confidential Information should be different if the IMM requests it than if the Midwest ISO does. Deleting the second definition of Confidential Information will eliminate the potential for future litigation concerning the issue of which definition should prevail. The Commission therefore directs the Midwest ISO to: (1) add to Section 1.37 the notion that trade secrets may be types of Confidential Information; (2) delete the second sentence from Section 54.4; and (3) add to Module A a definition of "Competitively Sensitive."

565. The Commission recognizes that in many instances, the Midwest ISO and market participants are likely to agree that certain types of that information designated Competitively Sensitive is, in fact, competitively sensitive. We do not wish to impose upon disclosing parties undue burdens to establish the sensitive nature of their information, nor should the Midwest ISO or the IMM be required to judge the sensitivity of every data item they receive. Accordingly, we will not require that parties justify at the outset why they designate information as Competitively Sensitive. Instead, as OMS and the Illinois Commission request, we will direct 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.

### e) Self-Scheduling Entities as Market Participants

#### *(1) The Midwest ISO's Proposal*

566. Section 38.2 of the proposed TEMT details the rights and obligations of market participants. Section 38.2.5 addresses the obligations of market participants, specifying in subsection (a) (ii) that generation-owning market participants must operate in a manner consistent with the standards, requirements or directions of the Midwest ISO. Section 38.3 states that Generation Owners and load-serving entities cannot engage in Market Activities unless they qualify as market participants, and specifies procedures for Generation Owners and load-serving entities that do not qualify as market participants to participate in the Energy Market through agreements with market participants.

#### *(2) Protests and Comments*

567. LG&E argues that the Midwest ISO's LMP congestion management proposal goes beyond the requirements of Order No. 2000 and Standard Market Design, and violates the voluntary market participation feature of the Standard Market Design.

568. LG&E and the Midwest ISO TOs believe that the proposal in Section 38.2.5 to assert authority over aspects of self-scheduling to serve native load violates section 201(b)(1) of the FPA which states that the Commission does not possess jurisdiction over any sales to retail load or over any rates, terms or conditions associated with such sales. These intervenors contend that the Midwest ISO could interfere with the scheduling of the load-serving entities' own resources in such a way as there would be a violation of state law. For these reasons, LG&E recommends that the Commission reject the filing. Moreover, according to the Midwest ISO TOs, such interference with entities performing self-scheduling violates the Commission October 2003 order requiring that the market not interfere with the continued ability of market participants to engage in bilateral transactions outside of the energy markets to serve all or part of their load or to continue to have the option of serving their load with their own resources. Further, state the Midwest ISO TOs, the tariff proposal discourages RTO participation because entities outside of the RTO can participate in the energy markets while not subjecting its retail load to the charges and risks associated with the energy markets tariff. The Midwest ISO TOs request the Commission to direct the removal of the provisions in the tariff that require the scheduling of the load-serving entities own resources be under the Markets Tariff and that entities become market participants to self-supply. The Midwest ISO TOs are willing to provide the information to satisfy the concerns of the Midwest ISO but do not want the Midwest ISO controlling the load-serving entity's scheduling of its own resources to serve its retail load.

569. The Midwest ISO TOs continue that the energy markets tariff mandates that once an entity becomes a Market Participant it must comply with the broad directives and procedures of the Midwest ISO, install equipment directed by the Midwest ISO and be subject to an array of approximately 25 charges contained in the tariff.[331]

570. The Midwest ISO TOs claim that the Midwest ISO compels participation even if the costs outweigh the benefits. The Midwest ISO TOs state that the mandatory nature of the tariff is contrary to the FPA which grants the Commission authority to regulate providers of service but not customers.[332] The Midwest ISO TOs also question the authority of the Midwest ISO to prevent an entity from scheduling if it does not become a Market Participant because such a matter is subject to state control as it involves the retail

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[331] The Midwest ISO TOs state that instead of this involuntary approach, the Midwest ISO should have made its markets as attractive as possible to entities and proposed a mechanism to mitigate harm to participating areas from the failure of certain areas not participating in the markets.

[332] Midwest ISO TOs at 24 (citing FPA section 201, 16 U.S.C. § 824).

sale of power to retail customers. The Midwest ISO TOs claim that Commission precedent supports customers being allowed to decide whether they want to take the service or not.[333]

571. Nebraska Intervenors agree with the Midwest ISO TOs that requiring entities that self-schedule to serve their own retail load to become a Market Participant discourages participation in the Midwest ISO. Nebraska Intervenors question the Midwest ISO's authority to exert jurisdiction over Nebraska load-serving entities' native load. Nebraska Intervenors request redevelopment of the provisions in the tariff regarding self-scheduling of resources to meet retail load to allow such self-scheduling to be accomplished without becoming a Market Participant under the Tariff.

***(3) Discussion***

572. As we have noted in previous orders, Order No. 2000 requires that RTOs develop a congestion management plan.[334] In our approval of the Midwest ISO proposal to implement an LMP congestion management plan, we approved the LMP pricing congestion management proposal since it was not opposed by Midwest ISO intervenors and furthered our long-term objective of a joint and common market for the Midwest ISO and PJM, which also utilizes LMP pricing congestion management.[335] We disagree with LG&E's contention that LMP pricing is beyond the requirements of Order No. 2000. LMP pricing congestion management is one congestion management option, and has been in use in several ISOs for some time. Considering that a majority of stakeholders support LMP pricing, no purpose would be served by additional adjudication in a rulemaking, as recommended by LG&E. Moreover, LG&E has provided no basis, such as a workable alternative proposal, that would justify the need to initiate such a proceeding.

[333] *See* Midwest ISO TOs at 34 (citing Central Hudson Gas & Electric Corporation, *et al.*, 86 FERC ¶ 61,062 at 61,208 (1999) (stating that the transmission tariff had to be separated from the rate schedules governing non-transmission functions, *e.g.*, operation of the spot market and administration of the NYRSC)).

[334] *See* RTO Order at 62,511. 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.

[335] *See* Declaratory Order at P 27-32.

573. We believe that the essence of LG&E's and the Midwest ISO TOs's concern, and the basis for their plea for voluntary participation, is their belief that the Midwest ISO TEMT proposal "mandates" that retail load be served by wholesale markets.[336] As LG&E correctly notes, generation resources can be designated self-scheduling or network resources. Therefore, LG&E has the option of designating all its generation resources as self-scheduled and thereby serve all retail native load with its own generation in the same way this would occur without an ISO energy market. LG&E also has the option of making the *choice* of designating some of its generation resources as network resources, and that choice results in the commitment of these resources to the ISO energy market. These resources must be available then for ISO instructions in order to maintain overall energy market reliability. In this second option, it is possible that LG&E retail load will require more energy than its self-scheduled units can provide, and therefore would have to obtain network resources from the ISO. To the extent that the first option is no different from how LG&E can schedule today without the need for wholesale energy and that the second option is based on a choice by LG&E, we do not consider the TEMT proposal a mandatory requirement that retail load be served by wholesale markets.

574. Nor do we see a concern with federal and state jurisdiction. To the extent LG&E must provide least-cost service per requirements of its state regulators, the ISO energy market, as a centralized least-cost dispatch system, is designed for that very purpose. Therefore, the issue for LG&E is how it balances its self-scheduling and network resource options to meet its state obligations. For this reason, we do not agree with LG&E's contention that the proposed Midwest ISO energy market intrinsically results in an unjust and unreasonable result for its state or its customers. Stated another way, the TEMT simply provides LG&E another option for providing least-cost service to its customers. We also do not agree with the Midwest ISO TOs that simply providing scheduling information to the Midwest ISO and responding to Load management and Emergency operations directives as required by Section 38.2.5 is an intrusion on state jurisdiction over retail rates and service, and therefore see no reason to remove these provisions from the TEMT.

575. With regard to the extent of the Commission's jurisdiction, we note that the proposed charges for Schedules 16 and 17 are applied to market participants for their use of the Energy Markets. As such, the charges apply to energy market services that are in our jurisdiction and are assessed on participants that use those services. No aspect of this arrangement applies to retail rates or services; hence there is no violation of FPA 201(b)(1).

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[336] *See* LG&E at 8.

576. Market participants under the proposed TEMT will designate resources as either self-scheduled or network resources in order that the Midwest ISO can schedule and plan the Day-Ahead Market. For purposes of maintaining system reliability and ensuring an efficient dispatch of resources, those resources designated in the day-ahead market must abide by their commitments. To provide resource designations, and then change their scheduling outside the Midwest ISO scheduling process, as is recommended by Midwest ISO TOs, denies the benefits of a centralized dispatch market and threatens the reliability of the system. Similarly, LG&E's requests to "opt out" of various proposed provisions to schedule the energy market likewise deny the benefits of the proposed energy market.

577. Finally, we do not consider the Nebraska Intervenors' scenario to be a realistic depiction of their energy market activities, and therefore we do not consider their recommendation to be appropriate. When these parties become market participants we expect they will self-schedule some portion of their resources and schedule additional amounts in the energy market. Also, we expect they will arrange to purchase energy in the market, as their needs require. Clearly, to the extent they use the energy market and benefit from it, they should share in its costs.[337]

### f) Generation Outage Scheduling

578. In section 38.2.5.h, the Midwest ISO proposes to coordinate Generator Planned Outages. It sets out a procedure for rescheduling outages to enhance the reliability of the Transmission Provider region and providing compensation.

579. Cinergy argues that the Midwest ISO should not have a unilateral right to reschedule a generator planned outage, requests specific time limits and notice requirements for rescheduling by the Midwest ISO and questions how the Midwest ISO will recover the costs of compensation. According to the proposed outage provisions, the Midwest ISO can reschedule planned outages only after an analysis of Available Transfer Capability and reliability impacts determines that a schedule will have a material impact, and the Midwest ISO has a documented, reasonable expectation of an Emergency. As well, rescheduling must be consistent with Good Utility Practice and compensation is provided.

[337] With respect to the Midwest ISO TOs' questioning of the benefits, compared to the costs, of the Energy Markets, we note that this issue is before the Commission in a paper hearing in Docket No. ER02-2595.

580. We consider it an appropriate condition of service under the TEMT that generators that take service from the Midwest ISO must comply with emergency actions ordered by the Midwest ISO for regional security. Accordingly, we consider this provision to be a reasonable requirement for generators, as it specifies these actions are to be taken in documented, reasonable expectations of emergencies.

### g) Generator Shortfall Uplift Charge

#### *(1) The Midwest ISO's Proposal*

581. The Midwest ISO proposes in Section 39.2.9(f) of the TEMT to guarantee the recovery of a Market Participant's generation offer (start-up, no-load, and energy offers) for resources committed by the Midwest ISO and scheduled in the Day-Ahead Market. According to Dr. McNamara, the shortfall experienced by generators will be uplifted to all market participants that are scheduled to purchase energy in the Day-Ahead Market.[338] Dr. McNamara states that the charge will be equal to the total payments necessary to cover the energy, no-load and start-up offers of resources selected in the Day-Ahead Market, divided by the total amount in megawatts of cleared bids to purchase energy and external bilateral transaction schedules for exports in the Day-Ahead Market. Dr. McNamara states that such transactions in the Day-Ahead Market should pay these uplift costs because they benefit from having the resources committed in the forward market.[339] Without such resources committed in the forward market, the Midwest ISO would have to commit units with higher production costs that can be used without start-up costs or no-load requirements. By guaranteeing resources that their costs will be met, the Midwest ISO is able to select and commit resources at minimum cost to meet the demand bid into the Day-Ahead Market.

582. The Midwest ISO also proposes, in Section 40.2.13 of the TEMT, to guarantee the minimum recovery of the market participants' start-up, no-load and calculated production costs for resources committed by the Midwest ISO in the RAC processes. Dr. McNamara states that, on a daily basis, the Midwest ISO will determine if a generator does not recover its start-up, no-load and production costs through the real-time energy market.[340] If there is a shortfall, the Midwest ISO will provide a guarantee payment to the generator to eliminate the shortfall and uplift the costs to: (1) market participants who withdrew

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[338] *See* Exhibit No. MISO-4 at p. 73. The day-ahead uplift charge is in section 39.3.1.c of the TEMT.

[339] *Id.* at 74.

[340] *See id.* at 77.

the energy during the operating day but did not have a day-ahead energy schedule; and (2) market participants with deviations from their dispatch instructions.[341]

### *(2) Protests and Comments*

583. The Midwest ISO TOs recommend that the generator shortfall uplift charges be rejected and removed from the tariff because they constitute retroactive ratemaking by seeking to recover under-recoveries in past charges in current rates.[342] The Midwest ISO TOs add that customers who thought that they had a price locked in in the Day-Ahead Market could be subject to an after-the-fact increase in the price, resulting in customers paying an above-market price and causing significant price uncertainty.[343]

584. The Midwest ISO TOs are also concerned that the uplift charge could be large, particularly at the beginning, until the Midwest ISO and market participants acquire experience in the market. Further, the tariff contains no caps on the uplift charge. The Midwest ISO TOs state that in other regions, customers have faced much higher bills than expected from uplifted costs.[344] The Midwest ISO TOs believe that the uplift provision is not equitable because the generators are paid regardless of whether the charges are recovered from customers by the Midwest ISO, which bills the TO for any shortage pursuant to Section 7.8(b).

585. LG&E states that self-scheduling entities will incur their own start-up and no-load costs as part of using their own resources, and therefore they shouldn't have to pay uplift costs, which includes similar costs for other generators.

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[341] The real-time uplift charge is included in Section 40.3.3.a.ii of the TEMT.

[342] The Midwest ISO TOs claim that the TEMT proposes to impose a surcharge to recoup past under-recoveries after the commodity has already been purchased, and that this has been found unlawful. *See* Midwest ISO TOs at 26 (citing Columbia Gas Transmission Corp. v. FERC, 831 F.2d 1135, 1140 (D.C. Cir. 1987)).

[343] Midwest ISO TOs state that the Commission has recognized that price uncertainty is problematic for the market. *See* Midwest ISO TOs at 26 (citing Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55,452 (Aug. 29, 2002), FERC Stats. & Regs. ¶ 32,563 at P 98 (2002)).

[344] *See* Midwest ISO TOs at 27 (citing "Six Month Review of SMD Electricity Markets in New England," Independent Market Advisor to ISO New England, at ff (February 2004)).

***(3) Discussion***

586. The Commission accepts the Midwest ISO's proposal to uplift generator costs that exceed the cleared market price, subject to the Midwest ISO making the modification discussed below. Such generator uplift proposals are quite common, and the Commission has accepted such proposals for other ISOs and RTOs.[345] Without the commitment of these resources whose costs are being uplifted, the bidders in the Day-Ahead Market may face higher costs as higher-cost resources that can be started up quickly with no minimum running times are committed. It is important to make sure that generators recover their costs to ensure an adequate source of energy in the market at the least cost. In fact, the Commission has rejected an uplift provision that may have precluded a generator from recovering all of its costs.[346] The Commission believes that the benefits of these generator guarantees outweigh the Midwest ISO TOs' concerns about price certainty.

587. The proposed allocation methodology for these costs is different than what the Commission has approved for other ISOs and RTOs who generally assess such costs to load. Nonetheless, the Commission believes that the Midwest ISO has proposed a reasonable allocation of the day-ahead generator shortfall uplift costs because the parties expected to benefit from the commitment of these resources will be paying the costs of committing them.[347] Moreover, the Midwest ISO's proposed methodology allocates a portion of the costs to virtual bidders, who would not pay under a load ratio share; thereby, spreading the uplift costs across a wider group of entities. The Commission finds the Midwest ISO's proposal to allocate real-time generator uplift charges reasonable because the proposed billing determinants allocate the uplift costs to those entities that cause higher costs for the region. For example, parties that choose to schedule all of their energy requirements in the Real-Time Market cause the Midwest ISO to bring online higher-cost resources with shorter startup times instead of lower-cost resources with longer startup times. Moreover, parties can avoid the charge by scheduling in the Day-Ahead Market instead of the Real-Time Market and by not deviating from the dispatch instructions.

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[345] *See* New England Power Pool, 85 FERC ¶ 61,379 (1998) (approving uplift charge). *See also* NYISO OATT, Schedule 1 and Attachment T (providing for recovery of Bid Production Cost Guarantees); CAISO OATT section 11.2.4.2.2.

[346] *See* New England Power Pool, 94 FERC ¶ 61,047 (2001).

[347] No protests have been filed contesting the proposed allocation of day-ahead and real-time generator uplift costs.

588. The Commission rejects LG&E's notion that self-scheduling entities should not have to pay the generator uplift charge. As the Commission stated previously:

> [S]tart-up and minimum load costs support both energy and ancillary services such as regulation and operating reserves, as well as redispatch to alleviate transmission congestion. Ancillary services are necessary for reliability, and all loads benefits from reliable operation of the transmission system. Since all loads benefit from the system's reliability and since loads from both ISO and bilateral markets may benefit from congestion management and ancillary services, it is not unreasonable that these costs be recovered through the scheduling charge from all loads.[348]

589. While other energy markets may have initially faced higher-than-expected uplift charges, the Commission has approved proposals to mitigate the uplift charges. For example, the Commission has approved the imposition of penalties on parties that engage in behavior that causes a material increase in price or in one or more guarantee payments.[349] The Commission also approved the NYISO proposal to adopt a real-time scheduling software, which was expected to reduce uplift costs by strengthening the integration of NYISO's day-ahead and real-time markets.[350] Additionally, the Commission approved NEPOOL's proposed revisions to the market rules to eliminate energy uplift payments to generators who game the system to receive unwarranted uplift payments.[351] The Commission stated that the problem experienced by ISO-NE was not present in NYISO and PJM, because NYISO and PJM determines whether the generator's costs are greater than the market clearing price on an daily basis whereas

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[348] *See* Central Hudson Gas & Electric Corporation, et al., 86 FERC ¶ 61,062 at 61,224 (1999).

[349] *See* New York Independent System Operator, Inc., et al., 90 FERC ¶ 61,317 (2000).

[350] NYISO stated that its day-ahead Security Constrained Dispatch software is decades old while its Security Constrained Unit Commitment and Balancing Market Evaluation were developed in the 1990s using different algorithms causing prices to inefficiently diverge and thus increase uplift costs. *See* New York Independent System Operator, Inc., 106 FERC ¶ 61,111 (2004).

[351] *See* New England Power Pool, 95 FERC ¶ 61,069 (2001). *See also* New England Power Pool, 94 FERC ¶ 61,047 (2001).

ISO-NE determined it on a hourly basis. We direct the Midwest ISO to clarify the TEMT to state that the Midwest ISO will determine, on a daily basis, whether a generator recovers its costs, consistent with Dr. McNamara's testimony. If parties believe that the uplift costs in the Midwest ISO are higher than expected (*e.g.*, gaming), they may file complaints with the Commission explaining the reasons for uplift being larger than expected and solutions to reducing the uplift.

590. The Midwest ISO TOs' concern that transmission owners may suffer due to the non-payment of others is misplaced. The shortfall that generators may occasionally experience as a result of operating when the market price is below their costs, and the shortfall transmission owners experience as a result of non-payment, are attributable to two different causes. The Commission believes that transmission owners are not similarly situated to sellers in the Energy Markets; therefore, the provision does not cause inequitable treatment between generators and transmission owners. Moreover, transmission owners experiencing uncollectible accounts attributable to jurisdictional transmission service may file with the Commission to recover unpaid debt costs in their transmission cost of service if they can demonstrate that their uncollectible accounts are attributable to jurisdictional transmission service.[352]

591. The Midwest ISO, a non-profit entity, is an agent for revenue distribution. It must pass the costs associated with generator shortfall guarantee payments on to market participants. The inclusion of uplift charges on the invoices of market participants is necessary to maintaining such guarantees. These charges do not constitute retroactive ratemaking as the uplift charge is a component of the formula rate that the Midwest ISO included in the TEMT. An accepted rate formula constitutes a rate filed, which satisfies the filing and notice requirement of section 205 of the FPA.[353]

### h) Data Provided to Control Areas

#### *(1) The Midwest ISO's Proposal*

592. Section 38.6.8 (c) (i) requires control area operators to receive Resource base points for each Generation Resource, to fulfill their obligations as Balancing Authorities during the Operating Day.

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[352] However, it has been the Commission's experience that most, if not all, of the uncollectible accounts are not attributable to jurisdictional transmission service.

[353] *See* Public Utilities Commission of the State of California v. FERC, 254 F.3d 250, 254-56 (D.C. Cir. 2001). *See also* Alabama Power Company v. FERC, 993 F.2d 1557, 1567-68 (D.C. Cir. 1993).

#### *(2) Protests and Comments*

593. Reliant states that the definition of Base Points is unclear as to whether it is only a megawatt instruction or a megawatt and price pair. If the definition includes prices, Reliant contends such information should not be provided to a control area operator, as this information has competitive value, and it is not necessary for reliable operation of the system.

#### *(3) Discussion*

594. We agree with Reliant that control areas do not need price information in their role as Balancing Authorities. Accordingly, we direct the Midwest ISO to define Base Points in its compliance filing as data that does not include prices.

### i) Inadvertent Energy

#### *(1) The Midwest ISO's Proposal*

595. Section 40.7 of the TEMT provides for a charge or credit to market participants for the surplus or credit attributable to inadvertent energy.[354] The Midwest ISO maintains a balance account of inadvertent energy, reported to NERC, and determines whether there is a surplus or credit by multiplying the average generation LMPs by the inadvertent energy megawatt amount. The Midwest ISO appears to allocate, on a daily basis, to market participants participating in the Real-Time Energy Market, a portion of the surplus or credit based on the billing determinants in Schedule 17.

#### *(2) Protests and Comments*

596. The Midwest ISO TOs contend that Section 40.7.2 should be rejected because it may result in double charging since market participants are already paying for balancing charges in the LMP settlement process. They also state that control areas should not be charged for inadvertent energy caused by non-affiliated generators or customers in the control area. The Midwest ISO TOs argue that if the provision remains, the Midwest ISO should: (1) not charge control area operators for the actions of independent generators; and (2) be required to address how it will allocate the in-kind energy payback it receives from external control areas. Reliant argues that all market participants should not pay for these costs, particularly those generators that follow scheduling and dispatch

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[354] Inadvertent energy represents the difference between a control area's net actual interchange and the net scheduled interchange.

instructions.[355] Instead, Reliant states that control area operators should be charged for inadvertent energy because they make the decisions affecting the net scheduled interchange.

### *(3) Discussion*

597. The manner by which the Midwest ISO intends to calculate Inadvertent Energy and charge for it is not clear.[356] For example, Section 40.7.1 of the TEMT states that the Midwest ISO will calculate Inadvertent Energy for each control area, but with centralized dispatch the intra-Midwest ISO schedules will not be tagged; therefore, there should not be net scheduled interchange between control areas in the Midwest ISO. The Midwest ISO does not explain in the TEMT how it will calculate the Inadvertent Energy for each control area, nor does it explain how it will ensure that there is no overlap with energy imbalance service. Additionally, Section 40.7.2 of the TEMT references billing determinants specified as “market ratio share in Schedule 17,” but Schedule 17 does not mention the term “market ratio share” and the Midwest ISO does not explain why the proposed billing determinants are just and reasonable. Moreover, as the Midwest ISO TOs point out, the method that the Midwest ISO will use to allocate in-kind payments with external control areas is not clear.

598. Therefore, we will reject the Midwest ISO’s Inadvertent Energy proposal, without prejudice to the Midwest ISO’s filing a new Inadvertent Energy proposal (with support addressing in detail the concerns stated above).[357] Additionally, we encourage the Midwest ISO to explain whether its Inadvertent Energy proposal is compatible with

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[355] Reliant states that generators that do contribute to inadvertent energy will already be exposed to the results of *ex post* LMP and uninstructed deviation penalties for their conduct and should not also have to pay for inadvertent energy.

[356] The Midwest ISO’s proposal is unsupported. The Midwest ISO did not file any testimony on the issue and did not address protestors’ concerns in its answer.

[357] The Midwest ISO should explain step-by-step how it plans on calculating Inadvertent Energy and charging or crediting the costs of Inadvertent Energy.

PJM's and whether it will facilitate a move to a common market.[358] The Commission encourages the Midwest ISO to file a new Inadvertent Energy provision when it files its Schedule 4 for Energy Imbalance Service to permit sufficient time for Commission review prior to the commencement of the Energy Markets.

### j) Attachment W: Market Participant Agreement

#### *(1) The Midwest ISO's Proposal*

599. Attachment W is a Form of Market Participant Agreement, which applicants seeking Market Participant status must execute in order to become a Market Participant.[359] Prospective market participants also must meet the criteria for a Market Participant, as specified in Section 38.2.2.[360] According to Section 38.2.2.h, upon submission of a complete Market Participation Application, the Midwest ISO shall investigate the applicant and, within 60 days, notify the Market Participant Applicant of its determination.

600. The Market Participant Agreement between the Midwest ISO and the Market Participant requires that the Market Participant supply the Midwest ISO all information that they deem reasonably necessary in accordance with Good Utility Practice. In addition, the agreement states that a Market Participant agrees to pay all charges under Schedules 16 and 17, and to notify the Midwest ISO in writing, within 24 hours, of any adverse material changes that may affect their status of a Market Participant.

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[358] If the Midwest ISO intends to use the billing determinants in Schedule 17 for inadvertent energy, it should include support demonstrating the proposed billing determinants are just and reasonable. Moreover, since the Commission has not yet acted upon the billing determinants in Schedule 17, the Midwest ISO should incorporate into section 40.7 of the TEMT its proposed billing determinants rather than reference Schedule 17 billing determinants which may change as a result of future Commission order.

[359] Attachment W, Original Sheet Nos. 1690-93.

[360] Module C, Original Sheet Nos. 366-75.

### *(2) Protests and Comments*

601. The Midwest ISO TOs state that the Midwest ISO is urging the execution of Attachment W as part of the asset registration process. They protest the requirement to sign Attachment W prior to the tariff becoming effective, a tariff that they note they are protesting. They request that they not be required to execute Attachment W or to become a Market Participant in order to provide data or to register assets.[361]

### *(3) Discussion*

602. We accept Attachment W, as amended, as part of the overall Market Participant Application process. Attachment W is a reasonable agreement that does not unduly burden or unduly discriminate against those parties seeking Market Participant status. We support the Midwest ISO's need to receive all relevant information to make a reasonable decision regarding grants of Market Participant status. However, we agree with the Midwest ISO TOs that the timing of the execution of the agreement needs to be modified. It strikes the Commission as unfair that an applicant must sign an agreement up to 60 days before the applicant will know whether the Midwest ISO has accepted its application. Furthermore, some participants have outstanding GFA issues that overlap with the requirement to pay Schedule 16 and 17 charges.

603. Therefore, we direct the Midwest ISO to modify Section 38.2.2.h so that it states that the Market Participant Agreement will be executed upon the Midwest ISO's approval of the rest of the Market Participant Application. In lieu of a signed Market Participant Agreement, the Midwest ISO may choose to require an applicant to submit a representation, such as a letter, that the applicant will be able to execute the Market Participant Agreement upon the approval of its application. The Midwest ISO should file these modifications within 60 days of the date of this order.

604. We direct the Midwest ISO to hold the requirement to execute the Market Participant Agreement in abeyance for parties that have outstanding GFA issues, pending resolution of those issues through a subsequent order in this proceeding.[362]

605. Finally, we direct the Midwest ISO to modify or clarify, within 60 days of the date of this order, the requirements listed in paragraphs 8.0 and 9.0 of the Market Participant Agreement. Paragraph 8.0 indicates that a Market Participant must notify the Midwest ISO in writing "of any unexpected material adverse change in circumstances that may

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[361] *See* Midwest ISO TOs at 62-63.

[362] *See* Procedural Order at P 78.

affect the Market Participant's status as a Market Participant, within twenty-four (24) hours of learning of the requirement."[363] Paragraph 9.0 states that a Market Participant must "notify the Midwest ISO in writing of any non-material adverse changes" that may affect the Market Participant status at least 72 hours prior to the change.[364]

606. The description "non-material adverse change" appears inherently at odds with itself, in that any adverse change that may affect Market Participant status would be material. The easiest remedy is to remove the modifier "non-," to make it simply a "material" adverse change. If the Midwest ISO intends for market participants to notify the Midwest ISO of non-material changes, the Midwest ISO is directed to so clarify. The Midwest ISO should add definitions of material and non-material adverse changes to the Market Participant Agreement and provide relevant examples of each. The Midwest ISO must also clarify what notification, if any, it will require of a Market Participant that expects a material adverse change that will affect the Market Participant's status, and what event will trigger the notification requirement.

## *K. Seams Issues*

### 1. Implementing the TEMT in the Midwest ISO Footprint

#### a) The Midwest ISO's Proposal

607. In its transmittal letter, the Midwest ISO recognizes the stakeholder concerns with seams issues and notes that it has begun discussions with bordering entities to develop seams agreements or operating agreements similar to the joint operating agreement between Midwest ISO and PJM (PJM-Midwest ISO JOA).[365] Under the PJM-Midwest ISO JOA the parties agree to coordinate and to exchange information to enhance system reliability and efficient market operations under the current market-to-non-market conditions and under the coming market-to-market conditions. In the market-to-market phase of the PJM-Midwest ISO JOA, a coordinated dispatch will be implemented to ensure appropriate LMP values at the market borders and to eliminate potential inefficiencies and gaming opportunities that otherwise could be caused by uncoordinated

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[363] Attachment W, Original Sheet No. 1691.

[364] Attachment W, Original Sheet No. 1692.

[365] Transmittal Letter at 23 (citing Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., 106 FERC ¶ 61,251 (2004)).

congestion management between adjacent markets.[366] The Midwest ISO states that it is discussing seams issues with its members and non-members in the western Mid-Continent Area Power Pool (MAPP) region.

608. The Midwest ISO adds, however, that it does not view the lack of seams agreements as a barrier to market startup, as it currently operates without these types of agreements on file with the Commission. The Midwest ISO notes that its reliability plan, including market startup, has been accepted by NERC and that its operations recently passed a NERC audit. It adds that, since it is the Reliability Coordinator for the region, the absence of a MAPP-Midwest ISO joint operating agreement will not inhibit its administration of the Energy Markets under the TEMT.

### b) Protests and Comments

609. Otter Tail states that, because of the unique circumstances of its control area, the TEMT cannot be implemented there. Otter Tail therefore requests that its native load and generation be exempted from the Energy Markets until the necessary seams agreements are in place. Otter Tail proposes that the Commission require it and the Midwest ISO to file a report on the status of seams negotiations within twelve months of the date of the Midwest ISO markets' startup, if no seams agreements are in place at that time. Otter Tail also proposes a tariff provision that, while exempting it from Module C, would require Otter Tail to pay the share of the capital and infrastructure costs, including carrying costs, that it would have otherwise paid once it begins participation in the Energy Markets.

610. Due to joint ownership of transmission lines, Otter Tail owns only 40 percent of the transmission facilities (100kV and above) in its control area. Much of that is non-contiguous, with multiple interties between Midwest ISO member and non-member facilities. Otter Tail adds that 46 percent of the transmission facilities in its control area are not under the control of the Midwest ISO and, therefore, will not be included in the Energy Markets or the Midwest ISO's congestion management program. Otter Tail claims that this could lead to instances of phantom congestion due to differences in scheduling rules.

[366] Other features of the PJM-Midwest ISO JOA include data exchange, coordination of outages and of regional transmission expansion planning, joint operation of emergency procedures and joint checkout procedures.

611. In addition, Otter Tail serves only 30 percent of the load and owns 46 percent of the generation capacity in its control area. Moreover, over half of its owned generation (405 of 702 megawatts) is from two units[367] that it jointly owns with non-Midwest ISO members. These units cannot be dispatched by the Midwest ISO due to potential breach of joint ownership contract claims. Otter Tail's control area also includes several non-jurisdictional load-serving entities.[368] Otter Tail states that this is atypical of Midwest ISO control areas (*e.g.*, Xcel), which are dominated by the load-serving entity's own native load plus network service and grandfathered transmission service agreements.

612. Otter Tail also notes that the North Dakota Operating Guides, which define the operating requirements during normal and contingency conditions for generators within the North Dakota Export (NDEX) region, require predefined curtailment levels from NDEX generators during times of reduced NDEX interface transfer capability. These curtailment levels may differ from the Midwest ISO's redispatch instructions. Otter Tail is concerned that, by following the NDEX curtailment instructions, if these instructions differ from the Midwest ISO's redispatch instructions, Otter Tail will be subject to Midwest ISO imbalance charges and unaccounted-for energy penalties. Such charges result in a disincentive to Otter Tail's participation in the Day-Ahead Market. Moreover, the presence of two sets of rules covering the Otter Tail control area – the North Dakota Operating Guides, applying to all of the generation, and the TEMT redispatch requirements, applying just to Otter Tail's wholly-owned generation – creates an additional seam between Midwest ISO members and non-members.

613. Because of these limitations and Otter Tail's ownership of only a small portion of the generation in its control area, Otter Tail claims that the Midwest ISO will not possess control of sufficient generation to allow for the efficient redispatch needed to send appropriate price signals and relieve transmission constraints.[369] This, according to Otter Tail, may lead to the imposition of significant additional costs on Otter Tail and its customers.

[367] Coyote Station and Big Stone Plant.

[368] Central Power Electric Cooperative, East River Electric Power Cooperative, Great River Energy, Minnkota Power Cooperative, and Missouri River Energy Services.

[369] *See* Otter Tail at 12.

614. In its supplemental comments, Otter Tail notes that there may be reliability concerns if the TEMT is applied to its control area. Otter Tail points out that the NERC Final Audit Report[370] questioned whether the contractual arrangement between MAPPCOR[371] and its non-Midwest ISO members adequately establishes the authority of the Reliability Coordinator, whether MAPPCOR or the Midwest ISO, over the non-Midwest ISO members. NERC directed the Midwest ISO to document its authority to fulfill all Reliability Coordinator functions and confirm concurrence with this authority by all control areas in the Midwest ISO area.

615. The North Dakota Commission and the Minnesota Department of Commerce agree with Otter Tail that the proposed Energy Markets are unlikely to work in Otter Tail's control area until adequate seams arrangements are in place.[372] Potential reliability and financial concerns arise from Otter Tail's unique control area, joint ownership between Midwest ISO and non-Midwest ISO members of the area's generation and transmission facilities and the unique operating characteristics of the North Dakota region.[373] The North Dakota Commission and the Minnesota Department of Commerce state that: (1) Otter Tail should be exempted from participating in the Energy Markets until the seams agreements are in place; (2) Midwest ISO loads within the Otter Tail control area that can participate in the Energy Markets through pseudo-ties should have an option to do so; and (3) periodic reports of progress at resolving the seams issues should be filed with the Commission. The North Dakota Commission also recommends that Montana-Dakota be exempted from the Energy Markets because Montana-Dakota

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[370] *See* Final Audit Report at 4, 13.

[371] MAPPCOR is a contractor to MAPP. It administers the MAPP Restated Agreement, which is the contract that governs the MAPP organization. *See* About MAPPCOR, http://www.mapp.org/content/about_mappcor.shtml

[372] *See* Additional Comments of the North Dakota Public Service Commission and the Minnesota Department of Commerce at 2-4. The North Dakota Commission states in its own separately-filed comments that negotiations to resolve the market to non-market seams have been ongoing for more than one year without progress. North Dakota Commission at 2.

[373] Three Commissioners from the Minnesota Commission expressed similar concerns about the reliability and financial implications for the region without proper seams agreements. The Minnesota Office of the Attorney General also filed a motion to intervene that expresses concern about seams issues with respect to the non-jurisdictional entities in Minnesota.

faces the same operating conditions as Otter Tail and its only direct connection to the Midwest ISO and the Energy Markets is through the Otter Tail control area.[374]

616. Minnkota, a member of MAPP but not of the Midwest ISO, argues that the Midwest ISO exaggerates the extent to which it solicited input from its stakeholders. According to Minnkota, the Midwest ISO only recently began discussions with entities in the Otter Tail control area and, furthermore, at those meetings, the Midwest ISO "[h]as been largely unreceptive" to concerns expressed regarding cost shifting associated with LMP without improving the value of service.[375] Additionally, Minnkota contends that the Midwest ISO has not considered the development of a coordination agreement and has also rejected suggestions that the Energy Markets be implemented in stages. Finally, Minnkota alleges that despite repeated attempts, the Midwest ISO has not demonstrated to Minnkota that the benefits of being in the Energy Markets outweigh the additional costs associated with participation.

### c) Discussion

617. Otter Tail raises valid concerns regarding its control area situation and the difficulties of applying the TEMT to it. The existence of regional generation operating rules, joint ownership of transmission lines and generators, pre-existing, non-OATT contracts, and the mix of Midwest ISO members and non-members and jurisdictional and non-jurisdictional entities no doubt increases the challenge of moving to the new world of competitive markets. Nevertheless, for several reasons, we find that Otter Tail belongs under the entire TEMT and, therefore, will deny its request for exemption from Module C.[376]

618. 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). 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

[374] The South Dakota Commission supports the motion filed by the North Dakota Commission and the Minnesota Department of Commerce. *See* South Dakota Commission at 1-2.

[375] *See* Minnkota at 16.

[376] The Commission will address in a subsequent order the issues Otter Tail raised concerning its GFAs.

the transmission and generation facilities in that 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, rather than market, services. Absent Otter Tail paying the exit fee and leaving the Midwest ISO altogether, the Midwest ISO remains the transmission provider for the Otter Tail system. In order to fulfill that responsibility and exempt Otter Tail from Module C, the Midwest ISO would have to create and administer a separate transmission tariff for the Otter Tail control area, in addition to the TEMT and the MAPP Schedule F that it already administers. Neither Otter Tail nor Midwest ISO have proposed such a tariff or a means of integrating that tariff with the TEMT. In addition, while incorporating Otter Tail into the Energy Markets is not without complication, the Midwest ISO has offered nothing to suggest that it cannot successfully be done by March 1, 2005.

619. Moreover, many of the various seams that could arise by placing Otter Tail under the TEMT (as well as other, equally difficult seams issues), must be resolved whether or not Otter Tail is in the market, particularly throughout the MAPP region.[377] Otter Tail has not demonstrated that its proposed exemption from the market will accelerate the process of seams resolution. In fact, Otter Tail staying out of the market, with only an obligation to file a progress report a year after the markets start, arguably removes the incentive for any of the affected parties, especially those non-jurisdictional entities that

[377] In addition to Otter Tail, jurisdictional utilities Aquila, Minnesota Power, Montana-Dakota and Xcel are members of both the Midwest ISO and MAPP, which also includes numerous non-jurisdictional transmitting utilities offering transmission service, in part under MAPP Schedule F and in part under individual tariffs determined by the Commission to allow the offer of reciprocal transmission service per Order No. 888. Jurisdictional utility Mid-American Energy is a member of MAPP but not of the Midwest ISO and offers transmission service both under Schedule F and its own OATT. Also like Otter Tail, several other MAPP members have jointly-owned transmission and generating facilities, and some must operate under the same North Dakota Operating Guides.

prefer to remain out of the market, to timely negotiate necessary seams resolution.[378] We further note that, were we to allow Otter Tail to remain out of the Energy Markets, other entities that have expressed a preference for markets (e.g., Great River Energy and the portion of Xcel's load located in Otter Tail's control area) would be denied full participation in them.

620. Similarly, Otter Tail's issue of reliability – i.e., the NERC Audit Report's request for clarity regarding the adequacy of the contractual arrangement between MAPPCOR and its non-Midwest ISO members to establish the authority of the Reliability Coordinator – may be a legitimate concern, if the Midwest ISO cannot document its authority to NERC's satisfaction. However, whether Otter Tail is part of the Midwest ISO markets has no impact on this concern – the Midwest ISO must establish its authority in either case.

621. Minnkota argues that the Midwest ISO stakeholder process failed to address the rather unique issues within the MAPP region portion of the Midwest ISO footprint. While we agree that this process within the MAPP region may have gotten off to a slow start, we are confident that now, beginning with a March 2, 2004 conference on seams issues held in Bloomington, Minnesota, the Midwest ISO is focusing on solutions with this region. To this end, the Procedural Order directed the Midwest ISO to continue to pursue seams agreements with neighboring entities regardless of the outcome of the TEMT proceeding.[379]

### 2. Monitoring and Mitigation Across Seams

#### a) The Midwest ISO's Proposal

622. Module D does not directly address issues concerning monitoring and mitigation across seams in the market. Coordination across the PJM and Midwest ISO RTO boundaries is provided for in the PJM-Midwest ISO JOA under both the current market-

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[378] In addition, it is unclear precisely what it means for Otter Tail to be exempt from Module C of the tariff. Does it mean that Otter Tail cannot buy and sell in the Day-Ahead and Real-Time Markets? What if Otter Tail buys one megawatt of power in the spot energy market; would it still remain exempt? It appears unjust to allow Otter Tail to avoid what it sees as the downsides of the Energy Markets, yet permit it to transact in them.

[379] Procedural Order at P 89, Ordering Paragraph J.

to-non-market conditions and the expected market-to-market conditions. In the market-to-market phase of the PJM-Midwest ISO JOA, a coordinated dispatch will be implemented to ensure appropriate LMP values at the market borders and to eliminate potential inefficiencies and gaming opportunities that otherwise could be caused by uncoordinated congestion management between adjacent markets.[380] The PJM-Midwest ISO JOA also provides that the parties will exchange information as the market monitors of PJM and the Midwest ISO request in order to facilitate monitoring of markets in association with their Commission-approved monitoring plans.[381] It provides that PJM and the Midwest ISO will address the matters raised and recommendations made by the parties' respective market monitors made in Market Monitors' Assessment of RTO Seams Issues in the Midwest submitted in Docket No. EL03-35-003.[382]

623. The Market Monitors' Assessment establishes the following points in the market-to-market coordination plan: (1) identification of constraints to be jointly managed; (2) real-time market coordination with an iteratively coordinated market dispatch to handle impacts of flows across market borders; (3) an evaluation of the feasibility of coordinating the interchange between RTO areas such as by using multiple "proxy buses" to represent the interconnections between markets with settlement provisions to prevent gaming when scheduled interchange does not match actual interchange between the areas; and (4) day-ahead market coordination subject to a feasibility assessment and benefits assessment. It also notes that the PJM-Midwest ISO JOA needs to have the market-to-market protocols finalized in the PJM-Midwest ISO JOA to a level of detail comparable to the level of detail on the market to non-market protocols.

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[380] Other features of the PJM-Midwest ISO JOA include data exchange, coordination of outages and of regional transmission expansion planning, joint operation of emergency procedures and joint checkout procedures.

[381] Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., issued on April 2, 2004. Section 4.2, Original Sheet No. 26.

[382] Market Monitors' Assessment of RTO Seams Issues in the Midwest, July 28, 2003.

624. Coordination between the Midwest ISO and other entities is less developed. To the south, the Midwest ISO has agreements with TVA, and SPP has been instructed to include seams coordination with Midwest ISO as a condition of receiving RTO status.[383] However, there are remaining areas adjacent to the Midwest ISO, as well as non-jurisdictional entities within the Midwest ISO, for which no seams agreements are in place.

### b) Protests and Comments

625. Wisconsin Retail and the Midwest TDUs say that extensive coordination on market power measures by the Midwest ISO and PJM should be occurring across major seams like the Wisconsin-Illinois border.

626. Otter Tail expresses concern that there may be opportunities for market gaming in the Otter Tail control area. The first such strategy is that market participants can employ circular schedules in the vicinity of Otter Tail control area to benefit from the Midwest ISO's congestion mechanism without providing any actual energy. One way of executing the circular strategy is to create a schedule in the Day-Ahead Market timeframe in such a way that the same power enters and leaves the Midwest ISO system at different interfaces with the loop closed outside the Midwest ISO region. Another way would be to take advantage of the immunity from congestion charges provided to some GFA schedules by importing and exporting over the same Midwest ISO interface. The gaming plan would be to get paid for relieving the Day-Ahead congestion in the Midwest ISO without any actual energy flow. Otter Tail says that information on NERC tagged schedules reserved in the MAPP OASIS won't be enough to catch all circular scheduling, such as that which is intra-control area and thus not subject to NERC tagging requirements. Also, if the circular scheduling is done using multiple scheduling entities, or if the schedule amounts vary slightly among the portions of the circular schedule, it will be nearly impossible for the Midwest ISO to identify the pieces of the circular schedule. Otter Tail says that this strategy is more likely to occur when the Day-Ahead LMPs at the Midwest ISO border differ significantly from each other.

627. Otter Tail says the second gaming strategy could occur with the use of non-Midwest ISO generation assets, which will not be subject to Midwest ISO's market monitoring. They also note that there will be numerous inefficiencies due to imperfections in modeling transmission in the region, scheduling of GFAs, and unresolved seams within and around the Otter Tail control area.

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[383] *See* Southwest Power Pool, Inc., 106 FERC ¶ 61,110 at P 2 (2004), *reh'g pending*.

#### c) Discussion

628. We believe that extensive coordination on monitoring and mitigation across the seam should be occurring between the Midwest ISO and PJM, but we believe that the market-to-market phase of the PJM-Midwest ISO JOA is the best place to deal with these issues. The Commission approved the general approach to the market-to-market phase of the PJM-Midwest ISO JOA on March 18, 2004, but declined to act on the specifics.[384] By waiting until the details of the Midwest ISO's planned markets, the Commission believes that more insight into the needs of the market-to-market phase of the PJM-Midwest ISO JOA will be attained. The Commission accepted the market-to-market provisions of the PJM-Midwest ISO JOA subject to the parties filing a revised PJM-Midwest ISO JOA, with more detail on that phase, within sixty days of the proposed effective date of the market-to-market phase. The Commission also said that the RTOs will be required to address in that filing intervenor concerns about that phase. We believe that the JOA process is the appropriate venue for addressing the concerns of Wisconsin Retail and the Midwest TDUs. When the Midwest ISO and PJM file the revised JOA prior to the commencement of the Midwest ISO's Day 2 markets, they should include the detailed provisions for the market–to-market implementation including a detailed plan for the associated monitoring.

629. With respect to Otter Tail's concerns, we also believe that substantial coordination will be needed to avoid gaming possibilities where there are no seams agreements. We encourage the Midwest ISO to pursue seams agreements with all its neighbors sooner rather than later. We encourage market participants to use the PJM-Midwest ISO JOA as a model or starting point to address gaming issues in seams agreements. In the absence of such agreements, the Midwest ISO should establish procedures to deal with gaming issues that arise.

### 3. Seams Agreements

#### a) The Midwest ISO's Proposal

630. In its transmittal letter, the Midwest ISO recognizes the stakeholder concerns with seams issues and notes that it has begun discussions with bordering entities to develop seams agreements or operating agreements similar to the joint operating agreement between the Midwest ISO and PJM (PJM-Midwest ISO JOA).[385] The Midwest ISO

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[384] Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., 106 FERC ¶ 61,251 at P 81 (2004), *reh'g pending*.

[385] *See* Transmittal Letter at 23 (citing Midwest Independent Transmission system Operator, Inc. and PJM Interconnection, L.L.C., 106 FERC ¶ 61,251 (2004)).

states that it is discussing seams issues with its members and non-members in the western Mid-Continent Area Power Pool (MAPP) region.

631. The Midwest ISO adds, however, that it does not view the lack of seams agreements as a barrier to market startup, as it currently operates without these types of agreements on file with the Commission. The Midwest ISO notes that its reliability plan, including market startup, has been accepted by NERC and that its operations recently passed a NERC audit. It adds that, since it is the Reliability Coordinator for the region, the absence of a MAPP-Midwest ISO joint operating agreement will not inhibit its administration of the Energy Markets under the TEMT.

### b) Protests and Comments

632. All the commenters support the Midwest ISO's efforts to develop agreements to resolve seams issues. However, MAPP argues that the Midwest ISO's "interface-by-interface" approach to resolving seams is inconsistent with recent Commission orders and limits efforts to promote efficient regional coordination.[386] MAPP believes that a more collaborative process will enhance reliability in the region and more efficiently resolve seams issues. Without uniform seams agreements in the region, MAPP is concerned that regional entities may not be able to ensure coordinated resolution of seams issues once the Energy Markets become effective and its members might not be treated similarly to PJM members. Nebraska Intervenors argue that the Commission should require the development of formal seams agreements because seams between MAPP and the Midwest ISO are far more complex than those between the Midwest ISO and Southwest Power Pool (SPP), for which the Commission required a seams agreement prior to SPP becoming an RTO.[387] Montana-Dakota states that 37 of its 40 total interconnections are with non-Midwest ISO members and that it is functioning as a pseudo-control area within WAPA's Upper Great Plains East control area; therefore, seams coordination is critical to

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[386] *See* MAPP at 2 (citing Southwest Power Pool, 106 FERC ¶ 61,110 at P 202 (2004), *reh'g pending*; ISO New England, 106 FERC ¶ 61,280 at P 95 (2004), *reh'g pending*).

[387] Crescent Moon Utilities urge the Commission to direct the Midwest ISO and SPP to negotiate with Crescent Moon Utilities a joint operating agreement that would emphasize operations and reliability and later include markets.

Montana-Dakota's operations. Montana-Dakota affirms that while such seams agreements are a bridge to a workable market, the best solution is to have either all utilities in or all utilities out of the Midwest ISO and the Energy Markets.[388]

633. While the parties support the resolution of seams issues through seams agreements, they disagree as to when those agreements must be in place. OMS supports the development of seams agreements prior to the commencement of the Energy Markets, but OMS states that the market can begin without final joint operating agreements in place for all parties as long as the Midwest ISO has made "arrangements" with all critical parties prior to the startup of the market.

634. Conversely, the Wisconsin, Minnesota and Montana Commissions believe that mere "arrangements" are insufficient and encourage the Commission to direct the negotiation of formal seams agreements. Further, they state that the Energy Markets should not start until the Midwest ISO assures its market participants and non-Midwest ISO utilities that the seams issues are fully resolved.[389] ATCLLC, Wisconsin Retail Customers Group, Alliant and Montana-Dakota agree that seams agreements should be in place prior to the implementation of the Energy Markets. ATCLLC and Wisconsin Retail Customer Group argue that the lack of a seams agreement is problematic and could impact reliability. Alliant notes that the proposed Energy Markets are more complex than the existing market structure, which requires coordination among transmission providers for both reliability and economic purposes.

635. Nebraska Intervenors, Xcel and Basin, *et al.*, state that such agreements should be developed prior to or concurrently with FTR allocations. Xcel explains that the electrical configuration in the historic MAPP region results in substantial loop flows that directly affect FTR allocations. Xcel states that given its significant integration with the non-Midwest ISO portion of the MAPP region, the Northern States Power Companies will not be able to evaluate the impact of these seams on their FTR allocation decisions until the Commission approves a seams agreement and the Midwest ISO has modeled FTRs to reflect it. Accordingly, Xcel believes that the Midwest ISO seams agreements on loop flows must be completed prior to FTR allocations rather than merely before the market commencement date.

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[388] Montana-Dakota argues that the Midwest ISO should not be permitted to file an unexecuted seams agreement. It also recommends that the Commission coordinate with the Rural Utilities Service, American Public Power Association and the Department of Energy to facilitate satisfactory seams agreements.

[389] *See* OMS at 26 n.26; Wisconsin Commission at 23-25.

636. In addition to the deadline for seams agreements, the parties appear to disagree as to who should negotiate the agreements. MAPP states that it is in active and productive discussions with the Midwest ISO to resolve the seams and that execution of an agreement may occur later this year. Nebraska Public Power District states that discussions between the Midwest ISO and non-Midwest ISO MAPP members are in their initial stages. However, Montana-Dakota states that there are so many parties in the Midwest ISO's western border that the Midwest ISO should negotiate with all of them instead of just MAPP, because MAPP has not been authorized by its members to negotiate seams agreements on their behalf.

637. Additionally, Crescent Moon Utilities argue that in most instances, there is no Midwest ISO transmission facility that delivers Crescent Moon Utilities' power. Crescent Moon Utilities acknowledge that when power flows over Minnkota's wires to an Otter Tail transmission substation and is stepped down to distribution, that transaction would be subject to the Energy Markets. However, Crescent Moon Utilities state that such use of a Midwest ISO member's facilities does not signify that the loads themselves are within the Midwest ISO market. As a result, the Midwest ISO cannot charge the Crescent Moon Utilities' load the charges associated with the Energy Markets.[390] Crescent Moon Utilities state that, to the limited extent the Energy Markets may apply, their application is restricted to the portion of the delivery involving Midwest ISO-controlled transmission facilities. Moreover, Crescent Moon Utilities argue that control area services, provided by Midwest ISO member utilities, do not support the extension of the Energy Markets, including the associated charges, to Crescent Moon Utilities' loads.

638. Basin, *et al.*, expresses concern that the Midwest ISO is attempting to expand its control over transmission facilities that were not actually turned over to it. Basin, *et al.*, quote a May 6, 2004 e-mail that the Midwest ISO's Mark Volpe sent to MAPP recipients: "[W]e will reiterate our position that the Midwest ISO footprint includes the entire control area. This includes the provision of transmission service over facilities where a [Midwest ISO] Transmission Owner has grandfathered (sic) rights for the use of those non-[Midwest ISO] operated facilities." Basin, *et al.*, note that if the Midwest ISO were to prevail on this issue, non-Midwest ISO member owners of transmission facilities who contract to provide transmission to Midwest ISO members would become subject to the TEMT

[390] Cinergy counters that Commission exemption of some Market Participants from obligations to pay charges under Schedules 10, 16 and 17 would be unjust and unreasonable because the Energy Markets will benefit all Market Participants. Further, such exemption would harm the other Market Participants in the region.

#### c) Discussion

639. While we will not grant Otter Tail's request for exemption from the markets, nevertheless we recognize that seams issues within the Midwest ISO footprint, particularly those involving Otter Tail and the MAPP region, should be resolved sooner rather than later. Moreover, though we agree with the Midwest ISO that the absence of seams agreements should not impede market startup, 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. We encourage market participants to use the PJM-Midwest ISO JOA as a model or starting point for seams agreements, particularly with respect to the seams with the various utilities in the MAPP region, including Otter Tail. We will require the Midwest ISO to file any resolution of seams, or a status report of progress on seams resolution including detailed plans as to how Midwest ISO will address seams absent agreements, within 60 days of the date of this order so that the most current seams resolutions can be factored into the FTR allocations.

640. We also find that two of the concerns raised by Otter Tail – joint ownership of generation and NDEX redispatch rules – can be accounted for in the market rules. We therefore direct the Midwest ISO to make the clarifications Otter Tail requests. While Otter Tail suggests that, due to these issues and others, the Midwest ISO will not be able to perform optimal dispatch and congestion management within its control area, we see no reason to make the perfect the enemy of the good, *i.e.*, some centralized redispatch is better (more efficient) than none at all.

641. While the ITAs between Otter Tail and non-Midwest ISO members in the Otter Tail control area may make the application of the Energy Markets more difficult, the Commission has no reason to believe that such obstacles cannot be overcome.[391] The Midwest ISO has not claimed that such obstacles would preclude the application of the energy markets to the North Dakota region.

### 4. PJM/Midwest ISO Joint and Common Market

642. OMS urges PJM and the Midwest ISO to recommit to the joint and common market, and in that spirit to set new timelines and commit to mileposts. We agree. We are encouraged by the significant progress made to manage the seam between PJM and Midwest ISO, such as the recently-completed PJM-Midwest ISO JOA and coordination between the market monitors of the respective ISOs. However, the planning necessary to

[391] These transmission arrangements are the result of the four bilateral ITAs between Otter Tail and four non-jurisdictional entities.

implement a joint and common market has not occurred in order to provide the Midwest ISO with the time needed to start its market. We expect PJM and Midwest ISO to renew their efforts once the Midwest ISO market is operational, and we will be directing the filing of their plans in future orders.

#### 5. Ameren Seam

643. Cinergy asserts that the market start for the Midwest ISO should be delayed until after the integration of AEP into the PJM market. According to Cinergy, starting the market before AEP is integrated will degrade the effectiveness of the market. Soyland contends that it needs a hold harmless provision to protect it from rate pancaking on the Ameren/Illinois Power seam.

644. We expect that both of these issues will be resolved before market start. AEP, based on current timelines, is expected to be fully integrated into PJM by October 1, 2004. Likewise, Ameren is a member of the Midwest ISO and Ameren is expected to complete its acquisition of Illinois Power in the fall of 2004.

### *L. Filing Disposition and Compliance Procedures*

645. We will accept and suspend certain tariff sheets of the proposed TEMT and permit them to become effective March 1, 2005, subject to conditions and further orders on the GFAs and Schedules 16 and 17.[392] We also accept certain tariff sheets to be effectiveon the date of this order, subject to conditions and further orders on the GFAs and Schedules 16 and 17.[393] We will specifically require the Midwest ISO to amend the definitions described in Appendix C to this order, and to make editorial changes to the TEMT as described in Appendix D.

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[392] These tariff sheets represent those the Midwest ISO originally proposed to become effective December 1, 2004.

[393] These tariff sheets include the tariff sheets that the Midwest ISO proposed to become effective June 7, 2004, which were accepted and suspended until November 7, 2004 by the Procedural Order. These tariff sheets do not include Section 12A of the TEMT, which the Commission rejected in the Procedural Order.

### 1. Compliance Requirements

646. The Midwest ISO will be required to make several further filings to comply with this order. Generally, there are three groups of compliance filings required by this order: (1) those due within 30 or 60 days of the date of this order; (2) those due prior to the start of the markets; and (3) those due after the start of the markets.[394]

647. First, within 30 days of the date of this order, the Midwest ISO must file a revised FTR allocation proposal and revised tariff sheets to implement the transition mechanisms described in section IV(B).[395] This order also directs the Midwest ISO to make a compliance filing within 60 days of this date of this order, concerning several issues as specified in the order. Additionally, the Midwest ISO is directed to conform the TEMT's Table of Contents to reflect "Creditworthiness" as section 11 and "Dispute Resolution Procedures" as section 12, consistent with the text of the TEMT.[396] We note that any compliance directive in this order which does not specify a compliance timeframe or trigger is also due within 60 days of the date of this order.

648. The Midwest ISO is also directed to make certain filings as discussed above prior to the start of the Energy Markets. These filings will be due at intervals 90, 60 and 30 days before the start of the Energy Markets. No later than 90 days before the Energy Markets startup date, the Midwest ISO must submit a filing, as discussed above, describing, among other things, contingency procedures. The Midwest ISO is also directed to submit information regarding market to market interactions as described above, 60 days prior to the effective date of the market-to-market phase of the Midwest ISO-PJM JOA. No later than 30 days prior to the Energy Markets' startup date, the Midwest ISO must certify its readiness for the start of the Energy Markets.

649. We expect the Midwest ISO and its stakeholders to learn from their experiences with the markets. These experiences will prove beneficial as we move to make long-term enhancements to the market. Therefore, the Midwest ISO is required to make filings 180 days and 270 days after the start of the Energy Markets, as described above, targeting long-term enhancements to the markets in areas such as long-term FTRs and marginal losses.

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[394] Although not date-specific, as discussed, the order also directs filings from either Midwest ISO or the IMM as instances require.

[395] The Midwest ISO should designate each tariff sheet revised in compliance with this order as a "Substitute Sheet."

[396] WEPCO at 4 and Detroit Edison at Appendix A.

### 2. Business Practice Manuals

#### a) The Midwest ISO's Proposal

650. The Midwest ISO states that the Market Protocols document has been replaced by the Business Practices Manuals, which are in the early stages of development. The Market Practices Task Force, the primary stakeholder forum, continues to develop detailed practices and procedures.[397] The Business Practices Manuals will provide the market participants with additional detail, serve as a reference for day-to-day functions of the energy markets, and supplement the rates, terms and conditions specified in the TEMT. Specifically, the Business Practices Manuals will provide background information, guidelines, business rules and processes established for the operation and administration of the different Midwest ISO markets; provisions of transmission reliability services and compliance with Midwest ISO settlements, billing, and accounting requirements. In contrast, the Midwest ISO states that the TEMT is a much higher level document and contains only the rates, terms and conditions necessary to effectuate service. The Midwest ISO adds that the Business Practices Manuals will not be filed with the Commission but will be subject to stakeholder consultations and review before enactment by the Midwest ISO. The Midwest ISO also adds that the Business Practices Manuals are intended to serve as operational tools for entities functioning within the Midwest ISO region.[398]

651. The Midwest ISO states that, for example, in Module C of the TEMT, the terms and conditions of services have been established that relate to the Day-Ahead and Real-Time Markets and FTR provisions for scheduling as well as the day-ahead processes that directly affect rates, terms and conditions. The Midwest ISO asserts that whatever occurs in the Day-Ahead and Real-Time Markets needs to be in the TEMT because there is a measurable financial impact on the market participants. However, the Business Practices Manuals will provide the market participants with details regarding scheduling timelines which are important to the Midwest ISO, as the Transmission Provider, to ensure that sufficient resources are available to meet the forecasted load.

[397] *See* Volpe testimony at 19-20.

[398] *See* Gardner testimony at 14.

652. In addition, the Midwest ISO notes that the Business Practices Manuals provide flexibility when a change in the provisions does not impact the rates, terms and conditions of service and therefore can be revised without the necessity of making section 205 filings with the Commission.[399]

### b) Protests and Comments

653. Intervenors[400] contend that the Midwest ISO proposes to resolve many issues through the use of unfiled procedures and the Business Practices Manuals which the Midwest ISO does not intend to file with the Commission. The Intervenors strongly urge the Commission to require the Midwest ISO to file all of its Business Practices Manuals which contain or affect rates, terms and conditions.

654. In particular, the Midwest ISO TOs state that if the Midwest ISO intends to impose substantial obligations with economic impacts, those procedures should be filed so that the market participants are allowed due process to challenge the procedure with the Commission.[401] The Midwest TDUs add that moving key components of conditions of service into the Business Practices Manuals will put the Market Participant in a position of having to file a complaint, reversing the burden of proof.[402] WEPCO also notes that certain provisions of the Business Practices Manuals are inconsistent with the TEMT and it appears that these inconsistencies take precedence over the proposed TEMT.[403] For example, WEPCO states that the Business Practice Manuals for Energy Markets appear to take precedence over the TEMT. The provisions for treatment of Intermittent Resources state that, "*notwithstanding any provisions of the [T]EMT to the contrary*, Generating Resources certified by the Midwest ISO to be Intermittent

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[399] *See* Volpe testimony at 22.

[400] Cinergy, Consumers, ELCON/AISI/ACC, Epic and SESCO, Great River, IMEA, Midwest ISO TOs, Midwest TDUs, Municipal Participants, OMS, Southwestern, Steel Producers, WEPCO, and WPS Resources.

[401] *See* Midwest ISO TOs at 42. *See also* Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶ 61,257 (1997) (PJM). (PJM not allowed to define obligations under tariff by reference to unfiled manuals and required that the specific obligations be filed.)

[402] *See* Midwest TDUs at 174.

[403] *See* WEPCO at 21.

Resources are not subject to any penalties for Uninstructed Deviations."[404] In addition, WEPCO asserts that provisions regarding the treatment of Demand Side Resources state that "*notwithstanding any provisions of the [T]EMT to the contrary*, Demand Side Resources certified by the Midwest ISO to be Intermittent Resources are not subject to any penalties for Uninstructed Deviations."[405] WPS Resources state that the Business Practices Manuals are supposed to contain requirements critical to market implementation but are incomplete in some instances, and nonexistent in other instances.[406]

655. ELCON/AISI/ACC states that the TEMT lacks clarity with regard to precise specifications and requirements of DRR Offers. ELCON/AISI/ACC specifically requests that the first drafts of the Business Practices Manuals be filed for Commission approval.[407] Consumers objects to the alignment of the TEMT and the Business Practices Manuals definitions. For example, there are differing definitions for an Asset Owner. ELCON questions which is the correct definition.[408] Great River contends that the TEMT appears to violate the Commission's filing requirement in two sections. Sections 45.6 and 69.2 of the TEMT respectively, make references to provisions in the Business Practices Manuals which affect the charge for FTRs and the must-offer criteria which, according to Great River, have an impact on how generation may be offered. Great River seeks to have both areas in the Business Practices Manuals added to the TEMT.

[404] *Id.* (citing Midwest ISO's Business Practice Manual for Energy Markets at 5-6 (emphasis added)).

[405] *Id.*

[406] *See* WPS Resources at 28.

[407] *See* ELCON/AISI/ACC at 18.

[408] *See* Consumers, Attachment A, Section I, Module A-Common Tariff Provisions.

### c) Discussion

656. Under our existing "rule of reason" policy, we see no reason to require that the Midwest ISO file the Business Practices Manuals. The Business Practices Manuals implicate our jurisdiction because, generally, they involve "the installation, operation, or use of facilities for the transmission or delivery of power…in interstate commerce.[409] However:

> [T]here is infinitude of practices affecting rates and service. The statutory directive [of section 205(c)] must reasonably be read to require the recitation of only those practices that affect rates and services significantly, that are *realistically* susceptible of speculation, and that are not so generally understood as to render recitation superfluous….[410]

657. We share WEPCO's concern that the Business Practice Manuals should not take precedence over the TEMT. The Commission's regulations require public utilities to file rate schedules "clearly and specifically setting forth all rates and charges for any transmission or sale of electric energy subject to the jurisdiction of this Commission . . . ."[411] Exceptions to penalty structures, such as those WEPCO identifies in the current drafts of the Business Practice Manuals, directly affect rates and should be included in the TEMT.

658. The Midwest ISO clearly indicates that the Business Practices Manuals are still being developed and refined based upon input and stakeholder process from the Market Practices Work Group. Furthermore, the Midwest ISO asserts that detailed policies and procedures will be included in sufficient detail and published prior to the start of the Energy Market on December 1, 2004.[412] Intervenors' arguments that the Business Practice Manuals are incomplete are, therefore, premature at this time. The Commission will not require a section 205 filing of the Business Practices Manuals because, while

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[409] *See* Prior Notice and Filing Requirements Under Part II of the Federal Power Act, 64 FERC ¶ 61,139 at 61,986 (1993) (explaining Commission jurisdiction with respect to all rates and charges that are "for or connected with," and all agreements that "affect or relate to," jurisdictional activities).

[410] *Id.* at 61,988 (quoting City of Cleveland v FERC, 773 F.2d 1368, 1376 (D.C. Cir. 1985)) (emphasis in original).

[411] 18 C.F.R.§ 35.1(a) (2004).

[412] *See* Volpe testimony at 20.

implicating our jurisdiction, they mostly involve general operating procedures. However, the Midwest ISO must make the documents available for public inspection on a permanent basis. We will require the Midwest ISO to revise the TEMT and any agreement on file with the Commission to the extent that they define rates, terms and conditions of service by reference to the Business Practices Manuals. Any reference to the specific rates, terms and conditions must be set forth in the TEMT and rate schedules as well.

The Commission orders:

(A) Module C, Section IV, Original Sheet Nos. 602-77, which were previously accepted and suspended to become effective subject to refund and further orders, shall become effective on the date of this order, subject to the conditions described in the body of this order.

(B) All Sections of the TEMT not addressed in the Procedural Order or in Ordering Paragraph (A) are hereby accepted and suspended to become effective March 1, 2005, subject to refund, conditions and further orders by the Commission.

(C) The Midwest ISO is hereby required to make compliance filings as described in the body of this order. To the extent that the order does not separately specify due dates for individual compliance requirements, the Midwest ISO should address those requirements within 60 days of the date of this order.

(D) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603, the Chief Administrative Law Judge is hereby directed to appoint a settlement judge in this proceeding within five days of the date of this order. The designated settlement judge shall have all powers and duties enumerated in Rule 603, and shall convene a settlement conference as soon as practicable. The settlement judge process shall last no longer than 60 days from the date of this order.

(E) At the conclusion of the settlement judge process, the parties are instructed to file a joint report to the Commission on the results of the proceedings, including further detail on how the Midwest ISO's proposed allocation of functions will be applied in practice and how issues of costs of liability will be resolved among the parties.

(G) The Midwest ISO TOs' motion to reject the TEMT is hereby denied.

By the Commission. Commissioner Kelliher concurring in part and dissenting in part with a separate statement attached.
( S E A L ) Commissioner Kelly concurring with a separate statement attached.

Magalie R. Salas,
Secretary.

## Appendix A

**Parties Filing Interventions in Docket No. ER04-691-000**

BP Energy Company
Central Iowa Power Cooperative
Clay Electric Cooperative, Inc.
ConocoPhillips Company
Coral Power, L.C.C.
The Energy Authority
Environmental Law and Policy Center of the Midwest
Illinois Commerce Commission
Illinois Municipal Electric Agency
Indiana Office of Utility Consumer Counselor
Indianapolis Power & Light
Iowa Utilities Board
Michigan Public Power Agency and Michigan South Central Power Agency
Minnesota Office of the Attorney General
Tennessee Valley Authority
Western Area Power Administration

**Parties Filing Interventions and Protests or Comments in Docket No. ER04-691-000**

**Alliant** – Alliant Energy Corporate Services, Inc.
**Ameren** – Ameren Services Company
**American Forest & Paper Association**
**AMP-Ohio** – American Municipal Power-Ohio, Inc.
**Archer-Daniels-Midland** – Archer-Daniels-Midland Company
**ATCLLC** – American Transmission Company LLC
**Basin, et al.** – Basin Electric Power Cooperative, East River Electric Power Cooperative, Inc., Central Power Electric Cooperative, Inc. and Capital Electric Cooperative, Inc.
**Cinergy** – Cinergy Services, Inc.
**Cleveland** – City of Cleveland, Ohio
**Coalition MTC** – Coalition of Midwest Transmission Customers
**Constellation** – Constellation Power Source, Inc., Constellation Generation Group, LLC and Constellation NewEnergy, Inc.
**Consumers** – Consumers Energy Company
**Corn Belt** – Corn Belt Power Cooperative

**Crescent Moon Utilities** – Basin Electric Power Cooperative, Heartland Consumers Power District, Minnkota Power Cooperative, Inc., NorthWestern Energy, Sunflower Electric Power Corporation and the Upper Great Plains Region of the Western Area Power Administration
**Dairyland** – Dairyland Power Cooperative
**Detroit Edison** – Detroit Edison Company
**Dominion** – Dominion Retail, Inc., Dominion Energy Marketing, Inc. and Troy Energy, LLC
**Duke** – Duke Energy North America, LLC
**Dynegy** – Dynegy Power Marketing, Inc. and Dynegy Midwest Generation, Inc.
**Edison Mission** – Edison Mission Energy, Edison Mission Marketing & Trading, Inc., and Midwest Generation EME, LLC
**ELCON/AISI/ACC** – Electricity Consumers Resource Council, American Iron and Steel Institute and American Chemistry Council
**Epic and SESCO** – Epic Merchant Energy LP and SESCO Enterprises LLC
**EPSA** – Electric Power Supply Association
**Exelon** – Exelon Corporation
**FirstEnergy** – FirstEnergy Service Company
**Great Lakes** – Great Lakes Utilities
**Great River** – Great River Energy
**IMEA** – Illinois Municipal Electric Agency
**Indianapolis P&L** – Indianapolis Power & Light Company
**LG&E** – LG&E Energy LLC
**Manitoba Hydro**
**Manitowoc Public Utilities**
**MAPP** – Mid-Continent Area Power Pool
**Marshfield** – Marshfield Electric & Water Department
**Michigan Commission** – Michigan Public Service Commission
**MidAmerican** – MidAmerican Energy Company
**Midwest Municipal Transmission Group**
**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 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 Municipal** – Minnesota Municipal Power Agency
**Minnesota Entities** – Minnesota Public Utilities Commission and Minnesota Department of Commerce
**Minnkota** – Minnkota Power Cooperative, Inc.
**Mirant** – Mirant Americas Energy Marketing, LP, Mirant Zeeland, LLC and Mirant Sugar Creek, LLC
**Montana-Dakota** – Montana-Dakota Utilities Company
**Municipal Participants** – Michigan Public Power Agency, Michigan South Central Power Agency, Department of Municipal Services of Wyandotte, Michigan and City of Hamilton, Ohio
**Nebraska Intervenors** – Lincoln Electric System, Omaha Public Power District and Nebraska Public Power District
**Nebraska Public Power District**
**NiSource Companies** – Northern Indiana Public Service Company, EnergyUSA-TPC Corp. and Whiting Clean Energy, Inc.
**North Dakota Commission** – North Dakota Public Service Commission
**NRECA** – National Rural Electric Cooperative Association
**Ohio Commission** – Public Utilities Commission of Ohio
**Ohio REC** – Ohio Rural Electric Cooperatives, Inc. and Buckeye Power, Inc.
**OMS** – Organization of MISO States
**Otter Tail** – Otter Tail Power Company
**PSEG** – PSEG Energy Resources & Trade LLC
**Reliant** – Reliant Energy, Inc.
**Southern Minnesota** – Southern Minnesota Municipal Power Agency
**Southwestern** – Southwestern Electric Cooperative, Inc.
**Soyland** – Soyland Power Cooperative, Inc.
**Steel Producers** – Steel Dynamics – Bar Products Division and Nucor Steel
**Strategic** – Strategic Energy, LLC
**TVA** – Tennessee Valley Authority
**WEPCO** – Wisconsin Electric Power Company

**Wisconsin Commission** – Public Service Commission of Wisconsin
**Wisconsin Retail Customers Group** – Citizens' Utility Board, Wisconsin Industrial Energy Group, Inc., Wisconsin Paper Council and Wisconsin Merchants Federation
**Wisconsin Transmission Customer Group**
**WPPI** – Wisconsin Public Power Inc.
**Wolverine** – Wolverine Power Supply Cooperative, Inc.
**WPS Resources** – WPS Resources Corporation
**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, Wisconsin Public Power, Inc. and Manitowoc Public Utilities
**Xcel** – Xcel Energy Services Inc.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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| Midwest Independent Transmission System Operator, Inc., | Docket No. ER04-691-000 |
| Public Utilities With Grandfathered Agreements in the Midwest ISO Region | Docket No. EL04-104-000 |

(Issued August 6, 2004)

Joseph T. KELLIHER, Commissioner *concurring and dissenting in part*:

I write separately to express my views on two aspects of the Commission's decision.

First, I concur with the portion of this order that rejects the Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) proposal to allow Midwest ISO, and require Midwest ISO's Independent Market Monitor (IMM), to provide confidential information to state commissions, state agencies that share regulatory responsibilities with the state commissions, or any organization formed by such state regulatory commissions. I agree with the order that Midwest ISO has not made an adequate showing to justify approval of its proposal to share confidential information with state entities.

In my view, in order to justify approval of Midwest ISO's proposed procedures for distributing confidential information to these state entities, Midwest ISO would need to demonstrate that (1) providing the state entities with confidential information possessed by Midwest ISO and the IMM is necessary for the state entities to discharge their legal responsibilities, and (2) the state entities cannot obtain such information under state law.[1] There is no doubt that state entities desire this information. However, there has been no demonstration made that access to confidential information held by Midwest ISO or the IMM is necessary to enable state commissions to carry out their statutory responsibilities.

[1] PJM Interconnection, LLC, 107 FERC ¶ 61,322 at 62,500 (2004)(Commissioner Kelliher, dissenting).

There has also been no demonstration that state commissions are or will be unable to obtain access to confidential information from Midwest ISO and the IMM under state law. In the absence of an adequate showing on either of these critical points, I cannot support providing state commissions or other state entities with confidential information from Midwest ISO or the IMM. I also believe any disclosure of confidential information to state agencies should only be permitted if adequate safeguards are established to maintain the confidentiality of this information.

Second, I dissent from the Commission's acceptance of the "must offer" requirement without compensation in the form of capacity payments. The order expresses concern with imposition of a must offer requirement absent capacity payments,[2] but approves it nonetheless, on the grounds that the requirement is an "interim measure."[3] It may well be that this must offer requirement will prove to be an interim measure. However, under the order it would only be replaced by a permanent plan that has been fully vetted through the stakeholder process and filed with the Commission. So, this interim measure may well be in place for some time. I would have rejected the must offer requirement pending establishment of a capacity market in Midwest ISO.

Joseph T. Kelliher

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[2] Order at P 410 ("We have concerns with the details of the must-offer requirement for DNRs without a corresponding capacity payment.").

[3] Id. at P 412.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc. — Docket No. ER04-691-000

Public Utilities With Grandfathered Agreements in the Midwest ISO Region — Docket No. EL04-104-000

(Issued August 6, 2004)

KELLY, Commissioner, *concurring*:

There are two aspects of today's order with respect to Midwest ISO's market monitoring and mitigation plan proposed in Module D upon which I wish to comment. Midwest ISO's proposed conduct and impact approach to mitigation is very similar to the mitigation approach the Commission has approved for New York ISO and ISO-New England, which seems to be working effectively. Midwest ISO's proposed use of BCAs to screen for mitigation is designed to limit the application of conduct and impact tests to those generators outside NCAs that have a specified effect on transmission constraints. Under Midwest ISO's proposal, BCAs would not be identified in advance by the IMM, but would be defined dynamically when constraints arise on flowgates. To determine which generators should be included in the BCA, the IMM would use a Generation Shift Factor (GSF) threshold test. The IMM would have the discretion to define GSF cutoff levels that it feels are required to determine which generators are to be included in the BCA, with an average GSF cutoff predicted to be 6 percent.

To eliminate the IMM's discretion in defining the GSF cutoff levels and to promote greater transparency in the BCA process, this order directs the IMM to use a default GSF cutoff of 6 percent and requires information about active BCAs and previous BCAs, and their associated flowgates, to be posted on Midwest ISO's website. I believe that these modifications to Midwest ISO's proposed BCA approach are appropriate.

However, this order also limits the use of BCAs as a screen for mitigation to a one-year period and requires the IMM to submit quarterly reports with the Commission on BCAs and their associated mitigation during this one-year period. The order also states that, if the Commission finds problems with the IMM's discretion in the application of mitigation with BCAs, it may terminate the BCA provision before the end of the one-year period. I believe that the majority's decision to terminate the use of BCAs after one year and to require the IMM to submit a report every three months within that year is unnecessary and unfounded. I also believe that, if the Commission were to find problems regarding the application of mitigation measures by any market monitor, it could take appropriate action at any time.

In addition, Midwest ISO's proposed tariff language in Module D includes phrases such as "causes or contributes to" or "contributes to" to identify certain proscribed conduct. This order requires Midwest ISO to replace any references to "contributes to" with the phrase "causes," on grounds that the phrase "contributes to" adds duplicative and unnecessary language and may create confusion and uncertainty. I do not share the majority's view that these phrases are duplicative or confusing, and would have accepted the tariff language as proposed. However, even if these phrases are considered duplicative, I believe that conduct which "causes" a certain outcome would necessarily encompass conduct which "contributes to" a certain outcome.

For these reasons, I concur with this order.

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| | ____________________________<br>Suedeen G. Kelly |