123 FERC ¶ 61,297

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Midwest Independent Transmission System Operator, Inc. — Docket No. ER07-1372-003

# ORDER GRANTING IN PART AND DENYING IN PART REHEARING AND GRANTING CLARIFICATION

(Issued June 23, 2008)

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1. In an order issued February 25, 2008, the Commission accepted the Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) proposed ancillary services market (ASM), as modified, and ordered compliance filings.[1] For the reasons discussed below, we grant in part and deny in part the requests for rehearing of the February 25 Order. We also clarify that sellers in the Midwest ISO with authority to sell energy at market-based rates will be authorized to sell ancillary services at market-based rates in the ASM upon inclusion in their market-based rate tariffs of the standard ancillary services provision that we adopt in this order. In an order issued concurrently with this order, we conditionally accept the Midwest ISO's 30-day compliance filing submitted in response to the February 25 Order and direct further compliance.

## I. Background

### A. History of this Proceeding

2. The Commission rejected without prejudice the Midwest ISO's initial ASM proposal and provided guidance to better enable the Midwest ISO to prepare and re-file a complete proposal.[2] The Commission explained that the filing did not include (1) a market power analysis supporting the proposed ASM; or (2) a readiness plan to ensure reliability during the transition from the current reserve and regulation system, which is managed by individual Balancing Authorities, to a centralized ASM managed by the Midwest ISO.

3. The Midwest ISO filed its revised proposal on September 14, 2007. On September 19, 2007, the Midwest ISO filed proposed amendments to its September 14 filing to correct minor typographical errors and provide inadvertently omitted language in certain definitions and Transmission and Energy Markets Tariff (TEMT or tariff) sections.

4. By order issued on November 19, 2007,[3] the Commission directed the Commission Staff to convene a Technical Conference to explore the issues raised by the Midwest ISO's market power analysis and proposed mitigation plan. Commission Staff held the Technical Conference on December 6, 2007.

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[1] *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,172 (2008) (February 25 Order).

[2] *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311, *reh'g denied*, 120 FERC ¶ 61,202 (2007) (Guidance Order).

[3] *Midwest Indep. Transmission Sys. Operator, Inc.*, 121 FERC ¶ 61,190 (2007) (Order Establishing Technical Conference).

### B. February 25 Order

5. In the February 25 Order, the Commission accepted the Midwest ISO's revised ancillary services market (ASM) proposal, as modified, and ordered compliance filings. Under the proposal, the Midwest ISO will determine operating reserve requirements and procure operating reserves from all qualified resources, in place of the current system of local management and procurement of reserves by the 24 Balancing Authorities. The Midwest ISO will also transfer and consolidate Balancing Authority responsibility in the Midwest ISO so that the Midwest ISO may become the North American Electric Reliability Council (NERC)-certified Balancing Authority for the entire Midwest ISO Balancing Authority Area. The Commission found that Balancing Authority consolidation will allow for more centralized and efficient management of ancillary services.

6. In the February 25 Order, the Commission also praised the proposal's simultaneous co-optimization approach, which seeks to minimize overall production costs in the Midwest ISO markets by coordinating the market-based procurement of energy and operating reserves. The Commission found that the simultaneous co-optimization approach will provide for the efficient acquisition and pricing of operating reserves, noting that variations of this approach are already in use by existing ISOs and regional transmission organizations (RTOs) that provide ancillary services through market-based mechanisms.

7. The Commission also found in the February 25 Order that the ASM proposal provides for greater participation by demand resources and scarcity pricing through the use of demand curves, as part of the co-optimization process. The Commission stated that the expected increased participation of demand resources will substantially improve efficiency and reliability.

8. The Commission also required the Midwest ISO to file a revised cost allocation because the Commission determined that the Midwest ISO's proposed cost allocation was inequitable and not reflective of cost causation principles. To address commenters' market power concerns, the Commission adopted in the February 25 Order a comprehensive package of market mitigation measures to ensure that ASM rates are just and reasonable as the region moves from cost-based rates to market-based rates.

## II. Rehearing Requests and Responsive Pleadings

9. Rehearing requests were filed by the parties identified in Appendix A, and the party abbreviations listed in Appendix A will be used throughout this order.

# III. Discussion

## A. Cost Allocation

### 1. Cost Allocation among Reserve Zones

#### a. February 25 Order

10. The Commission considered the Midwest ISO's proposal in the February 25 Order, which allocated costs using both market-wide and zonal allocators, to be: (1) inequitable because it requires market participants in zones with low reserve requirements to pay for the costs of their reserves plus an allocation of costs from the higher reserve requirement zones; and (2) not reflective of cost causation, since it allocates costs in high reserve requirement zones to the rest of the Midwest ISO. The Commission required the Midwest ISO to file a revised cost allocation that allocates the costs of reserves in the zone to load in the zone. The Commission found that such a cost allocation would be reasonable because it would ensure clear price signals, reflect cost causation and avoid inequities among market participants.

#### b. Requests for Rehearing

11. The Midwest TDUs question why load located near the resource providing the reserves should have to solely bear its costs when the reserves are procured to meet a system-wide dispersion requirement. The Midwest TDUs assert that the Midwest ISO, as Balancing Authority, will be procuring operating reserves to serve its entire system, and may procure an operating reserve from within a particular reserve zone due to the characteristics or needs of distant loads, or of generation and/or transmission facilities that are used to serve distant loads.

12. According to the Midwest TDUs, operating reserves may be procured from within an import-constrained zone to ensure that the system can withstand the unexpected loss of a large generator serving load outside of its host reserve zone. In this circumstance, the costs of these back-stop reserves, to the extent they exceed the reserve margin proportionate to local load, should be allocated market-wide or to load carrying less than proportionate operating reserves.

13. Duke Energy requests that the Commission clarify that the Midwest ISO must file a revised cost allocation that allocates the costs of reserves *required* by load in the zone to load in the zone. Duke Energy considers the alternative interpretation of the Commission's ruling, that the costs of all units *located in the zone that are providing reserves* to load in the zone must be allocated to load in the zone, to be unjust, unreasonable and unduly discriminatory when parts of the system are unconstrained and low-cost reserves located in one zone are available to serve load in another zone.

14. The Midwest TDUs argue that load in a constrained zone is not the sole cause of the procurement of reserves in the zone, noting that: (1) in a transmission outage event, operating reserves are procured from a particular area in order to ensure that the system can reliably respond to shifts in regional power flows, not solely to local load;[4] and (2) a major new transmission line to carry wind imports would be responsible for the locational procurement of operating reserves to protect a parallel lower-voltage line against an overload in the event the major new line trips. According to the Midwest TDUs, allocating the costs of operating reserves to the load that happens to be located in the same zone as the through transmission facility would not be equitable and would not reflect cost causation.

15. The Midwest TDUs fault the Commission for its mistaken premise that the Midwest ISO's proposed modified hybrid pricing is designed to make zones where prices are low pay for reserves in zones where prices are high. The Midwest TDUs note that each reserve zone pays for its locally-allocated operating reserves based on the clearing prices in that zone. Further, according to the Midwest TDUs, this hybrid approach would not allocate reserve costs across zonal boundaries if each reserve zone were to see reserves cleared proportionally to its load.

16. The Midwest TDUs also contend that the current Balancing Authority management of reserves is inequitable because it lacks the scope needed to practicably allocate operating reserve costs over the Balancing Authority borders to better track cost causation. The Midwest TDUs argue that, assuming the existing balkanized cost allocation would remain just and reasonable under the new operating reserve procurement rules, that finding is not a legal basis upon which to reject the modified hybrid cost allocation because there is a zone of reasonableness within which the Commission defers to the filing utility's preference.

17. The Midwest TDUs rely on the Commission's statement in the Guidance Order that a market-wide allocation of ancillary services costs is reasonable[5] and Commission precedent supporting region-wide cost allocation for operating reserve services.[6] The Midwest TDUs argue that the Midwest ISO's proposed hybrid allocation resembles the

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[4] The Midwest TDUs also note that a purely zonal cost allocation would result in local load paying for any operating reserves to cover an outage of a transmission line that is built to facilitate through traffic, and argue that this result is contrary to EPAct 2005's goal of promoting capital investment in transmission. Energy Policy Act of 2005, Pub. L. No. 109-58, §§ 1261 *et seq.*, 119 Stat. 594 (2005).

[5] *See* Guidance Order, 119 FERC ¶ 61,311 at P 106.

[6] *Calif. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at P 309 (2006).

approach followed in ISO-NE and PJM. Midwest TDUs also question why load located near a resource procured solely because of the 20 percent dispersion test should have to solely bear its costs, when its reserves were procured solely to meet the system-wide dispersion requirement.

18. Finally, the Midwest TDUs assert that the cost allocation that the Commission directed the Midwest ISO to set forth violates the filed rate doctrine. The Midwest TDUs argue that this cost allocation gives the Midwest ISO substantial flexibility to designate new reserve zones without a section 205 filing and with no minimum reserve zone size, thereby creating uncertainty as to which load will be paired with which generators in a reserve-zonal cost allocation.

### c. Commission Determination

19. We deny the requests for rehearing of the Commission's requirement that reserve costs in a zone be allocated to the load in the zone, but provide some clarification. Contrary to the arguments of certain parties, we consider this cost allocation reflective of cost causation, since reserves are procured to manage local reliability. We interpret Midwest TDUs' argument to be that there is some amount of reserves that are procured in a zone that are above and beyond the requirements of the zone, and therefore the costs of these reserves should not be allocated to the zone. We do not dispute Midwest TDUs' argument that reserves in one zone can benefit another zone, but, as the Commission acknowledged in the ASM Order, the primary purpose of the reserves in a zone is to manage local reliability in the zone; a zonal cost allocation thus best reflects cost causation.[7] Simply put, the Midwest ISO will not purchase reserves unless it can manage reliability in the zone in which the reserves are located.[8]

20. Moreover, certain parties appear to misunderstand the basis for the Commission's cost causation analysis. The costs of reserves in the zone are allocated to load in the zone because the Midwest ISO locates the reserves in a zone to manage reliability in that zone. Therefore, the zone design undertaken by the Midwest ISO ensures that there are adequate reserves deliverable to load in the zone. When a reserve resource in a constrained zone provides reserve MWs greater than the needs of load in the zone, and

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[7] *See* February 25 Order, 122 FERC ¶ 61,172 at P 418.

[8] We do not expect that the zonal cost allocation will result in unintended consequences, as the Midwest TDUs allege. The purpose of zones is to determine minimum reserve requirements for load within a defined geographic area, thereby ensuring reserves are located to effectively resolve local reliability needs and ensure optimum operating conditions. Therefore, by definition, the reserves needed to manage reliability will be in the zone. *Id.* P 417.

therefore provides reserve MWs to adjoining zones, such result is not the cause of the costs of reserves. Rather, it is instead a secondary outcome unrelated to the primary reliability purpose of the reserves in the constrained zone.[9] In other words, the load in the adjoining non-constrained zones may use reserves from the reserve resource in the constrained zone, but such load could just as easily have used reserves from any number of resources in the non-constrained zone. It would therefore be inappropriate to assign the costs of the reserve resource in the constrained zone to load in the non-constrained zone, since load in the non-constrained zone is not the *cause* of the constrained zone reserve costs.

21. We clarify for Duke that inasmuch as the purpose of zones is to determine the reserves needed to manage reliability in a geographic area, as the Midwest ISO explained in its filing, it is appropriate that reserves in the zone should be paid for by load in the zone. By the definition of a zone, low-cost reserves in an unconstrained zone cannot serve load in a constrained zone and an allocation of these costs to the constrained zone would therefore be inappropriate.

22. We agree with Midwest TDUs' assertion that outages of transmission facilities can affect the overall transfer capability of the grid. However, this does not change the fact that the Midwest ISO plans for these outages by procuring reserves locally in a zone to ensure that reliability can be managed in that zone when an outage occurs. Similarly, in the wind import example of the Midwest TDUs, the Midwest ISO will procure reserves to manage reliability for the load that will be affected by loss of a transmission line, and those reserves must be located so they are able to resolve local reliability needs, i.e., in the zone.[10]

23. We also deny Midwest TDUs' rehearing request with respect to the finding that the Midwest ISO proposal is inequitable. As we explained in the February 25 Order, it is inequitable to burden market participants that should be benefiting from the ASM, such as those market participants in unconstrained zones requiring lower reserves compared to the reserves required under the previous local balancing authority procurement of

[9] Since reserves in constrained zones are more expensive, we expect the co-optimization will minimize the amount of reserves from these resources consistent with the cost minimization objective function, thereby reducing the likelihood of excess reserves serving loads outside the constrained zone.

[10] For the reasons discussed, we disagree with the Midwest TDUs' assertion that load will pay for operating reserves that *happen* to be located in that zone. Reserves are in that zone specifically to manage local reliability.

reserves, with additional costs.[11] The fact that a portion of the reserve costs for these market participants is based on the zonal marginal clearing price (MCP) does not make the proposal more equitable, since these market participants in unconstrained zones are paying additional costs over their zonal costs. As the Commission explained in the February 25 Order, such an allocation to distant zones – that receive little or no reliability benefit – is not commensurate with the benefits of these reserves.[12]

24. We also reject Midwest TDUs' argument on rehearing that the Midwest ISO's proposed cost allocation is within a zone of reasonableness. The Commission previously determined that the Midwest ISO's proposal does not reflect cost causation, is inequitable and mutes the price signal benefits of the ASM.[13] While each RTO or ISO has its own allocation for ancillary service costs that reflects its unique market circumstances, we must take account of the circumstances of the Midwest ISO market, such as its size, in determining a just and reasonable cost allocation. It was these factors that were the most relevant to the Commission's determination in the February 25 Order.

25. With respect to the Midwest TDUs' reliance on the Commission's general guidance on cost allocation in the ASM Guidance Order, we note that this guidance was provided before the Midwest ISO Independent Market Monitor (IMM) conducted its market power analysis, which indicated significant constraints and market power in a number of constrained zones. Consequently, while a market-wide allocation may have appeared appropriate before the market analysis, the IMM's findings made clear that reserve zones would reflect significant local constraints and a reserve zone cost allocation would therefore better reflect cost causation and avoid inequities. Nonetheless, we consider the Commission's guidance to be just that and no more; therefore, the Commission's guidance was not a requirement and is not subject to rehearing or appeal.

26. In response to the dispersion test example presented by Midwest TDUs in their rehearing request, we consider the 20 percent dispersion test to be an operational backstop requirement in the unlikely and unusual event that a single resource may be chosen in the co-optimization process to provide regulating reserves above 20 percent of all regulating reserves over the Midwest ISO system. Therefore, we do not find it relevant to the appropriate cost allocation for reserves that will be procured to manage

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[11] This inequity is compounded by the fact that, under the Midwest ISO's proposed allocation, the market participants with the lowest reserve requirements are allocated the greatest additional costs, thereby eliminating the benefit of the ASM proportionally.

[12] *Id.* P 419.

[13] *See* February 25 Order, 122 FERC ¶ 61,172 at P 416-19.

local reliability and therefore typically will result in significant dispersion of reserves among the zones.

27. We consider the concern of the Midwest TDUs with respect to the uncertainty of the zones to which generators will be assigned to be an issue with the zone designation procedures of the Midwest ISO and not with its cost allocation. We note that in the February 25 Order the Commission required the Midwest ISO to analyze the pros and cons of a minimum reserve zone size,[14] and therefore the Commission is already addressing the Midwest TDUs' request for a minimum reserve zone size.[15]

### 2. Allocation of Ancillary Services Costs to Grandfathered Agreements

#### a. February 25 Order

28. The Commission determined that it is appropriate for the Midwest ISO to assess the transmission owner providing service under the carved-out grandfathered agreement (GFA)[16] charges for the reserves supplied in real-time through the ASM, in the event that these parties do not schedule sufficient reserves in real-time and therefore are relying on the ASM. The Commission considered this requirement equitable since it ensures that other market participants do not subsidize carved-out GFA transactions that lean on the system.

#### b. Requests for Rehearing

29. Alcoa argues that the ASM Order is ambiguous since the Commission uses Alcoa as an example of a carved-out GFA when Alcoa's GFA was labeled in the Commission's

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[14] *Id.* P 240.

[15] We do not consider the quarterly designation of reserve zones to be a violation of the filed rate doctrine. Market participants will know the zonal configurations prior to the incurrence of costs, and the costs of the ASM will be publicly available in the MCPs of reserves across the Midwest ISO.

[16] Carved-out GFAs are agreements held by Midwest ISO market participants that elected not to include these agreements in the Midwest ISO energy market and were not required to choose one of the settlement options made available by the Commission at the start of the Midwest ISO energy markets. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,236 (2004) (GFA Order)

GFA Orders[17] as an Option B GFA. Alcoa requests confirmation that the February 25 Order did not intend to restrict the application of its rationale to a particular type of GFA. Midwest Transmission Customers contend that the plain language of the February 25 Order applies to all GFAs, including GFAs that are classified as either Option A, B or C GFAs. Midwest Transmission Customers request that the Commission confirm that its rationale is not dependent on the label applied to each GFA. Midwest Transmission Customers maintain that the February 25 Order stated that GFA parties would be subject to ASM costs only to the extent that they did not schedule sufficient reserves in real-time,[18] and assert that the determination of whether a party schedules sufficient reserves in real-time has no linkage to Option A, B or C status.

30. Alcoa and Midwest Transmission Customers further contend that if the Commission permits double-charging of signatories to GFAs providing ancillary services, without making allowance for such charges assessed against affected entities, it is removing the primary economic benefit of entering into such agreements. They argue that the Commission would therefore effectively be frustrating all such contracts and declaring the agreements unjust and unreasonable. These parties assert that such an action would be inconsistent with the requirements of Federal Power Act (FPA) section 206 because the Commission would be effectively destroying the economic value of the contracts without determining that they are unjust and unreasonable or contrary to the public interest.[19]

31. The Michigan Power Agencies seek clarification regarding procedures for implementing the February 25 Order where the parties involved do not agree on whether or the extent to which any given carved-out GFA is properly construed as providing for ancillary services such that the carved-out GFA customer need not purchase such services under Schedule 3, 5 or 6. The Michigan Power Agencies assert that it is foreseeable that buyers and sellers under GFAs, as well as majority and minority participants in jointly-owned units, may have differing interpretations of these GFA provisions. For these reasons, the Michigan Power Agencies recommend that the Commission establish a procedure by which disputes involving the treatment of specific carved-out GFAs under ASM can be resolved in the same way the Commission ordered a separate proceeding under Docket No. EL04-104 and with the assistance of a settlement judge.

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[17] *Midwest Indep. Transmission Sys. Operator, Inc.; Public Utilities With Grandfathered Agreements in the Midwest ISO Region,* 111 FERC ¶ 61,042, at P 128, 158-59 (2005).

[18] February 25 Order, 122 FERC ¶ 61,172 at P 433.

[19] 16 U.S.C § 824e (2000 & Supp. V 2005).

### c. Commission Determination

32. We clarify that the Commission's determination on cost allocation of ancillary services in the February 25 Order applied only to carved-out GFAs and does not apply to Option A, B or C GFAs. In the February 25 Order, the Commission explicitly referenced only carved-out GFAs, and the precedent cited to by the Commission applied only to carved-out GFAs.[20] The Commission's reference to Alcoa's Option B contract as a carved-out GFA was an inadvertent error, and cannot be construed as the Commission's intent to apply its cost allocation findings to GFAs other than carved-out GFAs.

33. Parties to Options A, B and C GFA contracts either voluntarily made the choice to participate in the Midwest ISO markets and therefore willingly made themselves subject to the costs of these markets, or were required to do so in the GFA Order. Contrary to the assertions of certain parties, the fact that Options A, B and C GFA market participants must pay the costs for the services they receive from the Midwest ISO markets is reasonable and such payment for services provided does not frustrate their GFA contracts or destroy the economic value of those contracts. Rather, parties to Options A, B and C GFA contracts are in the same position as all other market participants with respect to their ability to self-supply their reserves. That is, just like Options A, B and C GFA parties, other market participants can self-supply their reserves, and that fact does not make an allocation of ASM costs unreasonable, as the Commission explained in the February 25 Order.[21]

34. Consistent with the Commission's determination of cost and scheduling responsibility for GFAs in the energy market,[22] the determination of whether the carved-out GFA contract provides for ancillary services such that the carved-out GFA customer need self-supply or purchase such services under Schedule 3, 5 or 6 is outside the scope of this proceeding. The transmission owner or independent transmission company[23]

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[20] *Id.* P 440.

[21] *Id.* P 324 ("We do not consider it appropriate to exempt self-scheduling entities from the costs of the ASM since the management of ancillary services by the Midwest ISO provides reliability benefits for all market participants, including self-scheduling entities.").

[22] *See* GFA Order, 108 FERC ¶ 61,236 at P 300.

[23] *See* Midwest ISO, FERC Electric Tariff, Second Revised Sheet No. 89 § 1.160 (defining independent transmission company as a company that has executed an Appendix I Agreement with the transmission provider and the transmission owners).

participant is the entity responsible for incurring ASM costs and therefore it should be the entity making the determination on whether the carved-out GFA customer is meeting its obligation, if any, to supply ancillary services. Therefore, we see no need for settlement judge procedures.

### B. Market-Based Rates

#### 1. February 25 Order

35. In the February 25 Order, the Commission assessed the Midwest ISO's market power study and accepted market-based rate pricing for ancillary services. The Commission found that to the extent any seller could exercise market power in the ASM, the potential exercise of market power would be effectively mitigated by the Midwest ISO's proposed mitigation plan. The Commission also found that spinning and supplemental reserves are substitutable and therefore accepted the IMM's combined analysis of the two reserves into a single category – contingency reserves.

#### 2. Requests for Rehearing

36. Midwest Transmission Customers argue that the Commission must ensure that the ASM is competitive before it can grant market-based rate authority, and asserts that the Midwest ISO has not shown that the ASM is competitive. Midwest Transmission Customers assert that the Commission, in the February 25 Order, concluded that the mitigation proposed by the Midwest ISO is an appropriate method of addressing the market power risks identified in the market power analysis. According to Midwest Transmission Customers, this implies that regardless of whether competitive forces exist, "conduct and impact tests are a panacea sufficient to justify [market based rates]."[24] Midwest Transmission Customers maintain that appellate courts have concluded that market-based pricing results in just and reasonable rates where (1) a competitive market exists and (2) the applicant lacks or has adequately mitigated market power. Midwest Transmission Customers argue that the Commission cannot simply assume that the first prong of this test is met, and that there must be "empirical proof … that a competitive market exists for the relevant product."[25]

37. Midwest Transmission Customers also argue that the Commission erroneously accepted the IMM's market power study. Midwest Transmission Customers state that in accepting the IMM's study, the Commission concluded that the seven geographic submarkets identified in the study will correspond to the reserve zones in the initial start-

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[24] *See* Midwest Transmission Customers Comments at 6.

[25] *Id.* at 9.

up of the ASM. However, Midwest Transmission Customers note that the geographic regions in the study do not necessarily reflect the reserve zones that will be used at the time of ASM start-up, and that the ASM reserve zones that will be used at start-up are not currently known. Midwest Transmission Customers argue that without a market power study that clearly defines the relevant geographic market, the Commission cannot accurately assess market power. Midwest Transmission Customers state that the market power study therefore does not provide any basis for approving market-based rates in the ASM.

38. Midwest TDUs and Midwest Transmission Customers argue that the Commission erred in combining spinning and supplemental reserves into a single product market called “contingency reserves.” Midwest TDUs state that, contrary to the IMM’s assertion, there is no evidence in the record to show that substitution will adequately defeat price increases associated with the attempted exercise of market power. Midwest TDUs assert that the IMM failed to examine the price effects of combining spinning and supplemental reserves into a single product market. They argue that the IMM’s analysis departs from standard economic approaches to product market definition because the IMM did not examine whether the effect of substituting spinning reserves with supplemental reserves indirectly through the energy market would have caused the spinning reserve price to rise above a competitive level. The Midwest TDUs express particular concern that generators may be able to exercise market power by withholding ramp and driving prices to scarcity levels.

39. Midwest TDUs also note that regional reliability organizations (now regional entities) in the Midwest ISO footprint such as Reliability*First* Corporation and Midwest Reliability Organization distinguish between and establish distinct requirements for spinning and supplemental reserves. Midwest TDUs also point out that the Commission’s *pro forma* OATT treats these reserves as separate products because it does not allow transmission customers to buy only supplemental reserves. Midwest TDUs also argue that improperly treating the two kinds of reserves as a single product could mask market power problems, i.e., pivotal suppliers requiring mitigation.

40. Ameren asserts that the February 25 Order did not state whether, by accepting market-based rate pricing for ancillary services, the Commission authorized sellers in the Midwest ISO energy market with market-based rate authorization to also sell ancillary services at market-based rates. Ameren argues that the omission of market-based rate authorization for individual sellers in the Midwest ISO ASM makes the February 25 Order unlike previous Commission orders authorizing markets for ancillary services. Ameren states that in Appendix C to Order No. 697 the Commission specifies language to be incorporated in the market-based rate tariffs of sellers offering ancillary services in RTO and ISO ancillary service markets for which the Commission has authorized market-based rate pricing. Ameren therefore requests that the Commission clarify that the February 25 Order authorized sellers with the authority to sell energy and/or capacity

at market-based rates in the Midwest ISO to also sell ancillary services at market-based rates, provided that they include in their market-based rate tariffs standard language regarding ancillary services sales such as that provided in Appendix C to Order No. 697.

### 3. **Commission Determination**

41. We deny Midwest Transmission Customers' argument on rehearing that the Commission must make a separate finding that the ASM is competitive. In Order No. 697-A, the Commission rejected a similar argument, finding that "[u]nder the FPA, the Commission is not bound to a particular ratemaking methodology in setting rates as long as rates fall within a zone of reasonableness."[26] The Commission explained that the zone of reasonableness can take into account "all relevant public interests, both existing and foreseeable."[27] In permitting market-based rates, the Commission has taken two approaches: (1) a finding that an individual seller and its affiliates lack or have mitigated market power; or (2) a finding that a market is competitive. As we explained in Order No. 697-A, the Commission has primarily used the first approach since the mid-1980s. In addition, with regard to rates for sales within RTOs/ISOs, even if sellers have been found to lack market power on an individual seller basis, the Commission has relied on a blend of market and cost-based elements (e.g., some form of cost cap or mitigated bids) to ensure just and reasonable rates. The Commission has the discretion to select its approach so long as the resulting rates fall within the zone of reasonableness. Here, consistent with Commission precedent, the Commission found that the Midwest ISO's proposed mitigation plan will adequately protect consumers from individual sellers exercising market power.

42. We also deny Midwest Transmission Customers' rehearing argument that the Commission cannot accurately assess market power because the geographic submarkets identified in the market power study may not necessarily correspond to the reserve zones in the ASM. The same criteria used to determine the geographic clusters in the market power study, i.e., transmission constraints, will be used to determine the reserve zones in the ASM at start-up. The reserve zones in the ASM are therefore likely to be the same as the geographic submarkets in the market power study at market start up, and will vary depending on the constraints. However, the Midwest ISO's mitigation methods will address these problems as the mitigation measures naturally adapt to changing reserve

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[26] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 72 Fed. Reg. 39,904 (July 20, 2007), FERC Stats. & Regs. ¶ 31,252 (2007); *clarified*, 121 FERC ¶ 61,260 (2007) (Order Clarifying Final Rule); *order on reh'g*, Order No. 697-A, 73 Fed. Reg. 25,832 (May 7, 2008), FERC Stats. & Regs. ¶ 31,268, at P 425 (2008).

[27] *Id.*

zone definitions because the reference levels are resource-specific, not reserve zone-specific.[28] The Midwest ISO's mitigation measures will therefore be effective in restricting the exercise of market power even if local conditions and reserve zones change.

43. We deny Midwest TDUs' and Midwest Transmission Customers' rehearing argument that because spinning and supplemental reserves are not always completely substitutable, the IMM's market power analysis is flawed. As explained in the February 25 Order, the Midwest ISO can substitute supplemental reserves with spinning reserves or create spinning reserves from supplemental reserves by committing resources that would otherwise supply supplemental reserves as off-line resources.[29] Since the procurement of spinning reserves can generally be substituted with supplemental reserves, for the purposes of analyzing the potential for market power in a forward looking study, we conclude that it is reasonable to combine the two product markets. Furthermore, as the February 25 Order recognized, even though some resources qualify as supplemental reserves, but not as spinning reserves, the effective substitutability of resources between energy and different types of reserves on the Midwest ISO system makes it reasonable to evaluate the two products as part of a single product market for purposes of identifying market power.[30] Because we find that spinning and supplemental reserves are part of a single economic market for purposes of market power evaluation, we also deny Midwest TDUs' rehearing argument that creating a single market for these reserves may mask market power problems in the ASM.

44. Midwest TDUs erroneously suggest that because the Commission's *pro forma* OATT does not allow transmission customers to buy only supplemental reserves, this implies that supplemental and spinning reserves are not substitutable. While they are correct that a transmission provider needs some of each type of reserve, in general, the same resources that can provide supplemental reserves can provide spinning reserves as well. Similarly, that regional reliability organizations (now regional entities) in the Midwest ISO footprint such as Reliability*First* Corporation and Midwest Reliability Organization distinguish between spinning and supplemental reserves does not demonstrate that these are distinct products for purposes of market power analysis.

45. We also deny Midwest TDUs' argument that generators can exercise market power in the ASM by withholding ramp. Withholding ramping capability is analogous to physical withholding of energy in the spot market, and the presence of the IMM is an

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[28] February 25 Order, 122 FERC ¶ 61,172 at P 50.

[29] *Id.* P 58.

[30] *Id.*

adequate safeguard to protect against the exercise of market power through physical withholding in the ASM. If physical withholding is found, such as a generator offering a lower ramping capability than it has, the Commission would expect the IMM to report any such occurrences to the Commission, and additional measures to mitigate such behavior could then be enacted.

46. In response to Ameren's concern that the February 25 Order did not address whether market participants with market-based rate authority in the Midwest ISO energy market are authorized to sell ancillary services at market-based rates in the ASM, we clarify that sellers in the Midwest ISO market that are authorized to sell energy at market-based rates are authorized to also sell ancillary services at market-based rates in the ASM, effective as of the start of the ASM, upon inclusion in their market-based rate tariffs of the following standard ancillary services provision:[31]

> Midwest ISO: Seller offers regulation service and operating reserve service (which include 10-minute spinning reserve and 10-minute supplemental reserve) for sale to the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and to others that are self-supplying ancillary services to Midwest ISO.

### C. Monitoring and Mitigation Plan

#### 1. Market-Based Rates

##### a. February 25 Order

47. The Commission accepted the Midwest ISO's proposal to use a conduct and impact approach to mitigate the market power concerns identified in the market power analysis.[32] The monitoring plan establishes that the IMM will monitor the markets and services provided by the Midwest ISO, including the proposed ASM. The mitigation plan imposes mitigation in the proposed ASM upon entities in constrained areas (areas in which a constraint is actively binding) that fail conduct and impact tests such that their conduct is inconsistent with competitive outcomes (as indicated by conduct threshold

[31] In Appendix C to Order No. 697, the Commission adopted standard ancillary services provisions for PJM, NY-ISO, ISO-New England, and the California Independent System Operator. The Commission stated that it would post these provisions on its website and update them as appropriate.

[32] *See* February 25 Order, 122 FERC ¶ 61,172 at P 89.

levels) and would result in a change in one or more prices in the energy market, prices in the ASM, or certain make-whole payments (by exceeding impact thresholds).

### b. Requests for Rehearing

48. Midwest TDUs argue on rehearing that the Midwest ISO's market mitigation measures are not tailored to the market power concerns identified in the market power analysis. They maintain that the mitigation measures are the same as those designed and proposed by the Midwest ISO prior to the market power study in its initial ASM proposal.[33] Midwest TDUs also assert that the mitigation measures are similar to those used in ISO-New England and New York ISO.[34]

49. Midwest TDUs argue that the Commission should require the Midwest ISO to apply its mitigation measures on a market-wide basis when there are pivotal or dominant suppliers. At a minimum, they argue that such mitigation measures should apply in regulation markets and in spinning and supplemental reserves markets if the Commission requires the Midwest ISO to separately analyze those markets.[35] Midwest TDUs assert that the market power analysis found that there were pivotal suppliers in 2.6 percent of hours for the entire Midwest ISO regulation market and that hours with pivotal suppliers occurred most frequently during the winter months.[36] Midwest TDUs argue that pivotal suppliers will cause substantial financial harm to consumers because they may be able to raise prices throughout the Midwest ISO market during more than 200 hours per year. They add that sellers may predict that they will be pivotal during winter months, which increases the chances of the successful exercise of market power. Midwest TDUs conclude that these findings necessitate the application of mitigation measures on a market-wide basis and argue that the Commission cannot approve market-based rates without sufficient mitigation. Midwest TDUs maintain that the Commission has

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[33] *See* Guidance Order, 119 FERC ¶ 61,311 at P 11.

[34] Midwest TDUs argue that the February 25 Order should have explicitly mentioned the Kirsch Affidavit and his participation in the technical conference. They maintain that the Commission is obligated to respond to Dr. Kirsch's objections and evidence. *See* Midwest TDUs October 15, 2008 Comments, Kirsch Aff.

[35] Midwest TDUs assert that the IMM can determine market competitiveness by assessing the market's structure on a day-ahead or real-time basis using market concentration and/or pivotal supplier measures.

[36] Midwest ISO September 14, 2008 Filing, Market Power Study for the Midwest ISO's Proposed ASM at 23 (Market Power Study).

previously accepted a mitigation measure to address risks associated with RTO-wide pivotal suppliers.[37]

### c. **Commission Determination**

50. We deny Midwest TDUs' request for rehearing because they have not demonstrated that the Midwest ISO's conduct and impact approach will be insufficient to address the market power risks identified in the market power analysis.[38] As explained in the February 25 Order, the application of mitigation measures within constrained electrical areas appropriately targets the sub-regional market power concerns identified in the market power analysis. The similarities among the Midwest ISO's mitigation plan for the ASM, Midwest ISO's mitigation plan for its energy market, and mitigation measures employed in other markets provides additional assurance that mitigation measures will function appropriately in the ASM.[39] Any similarities between the Midwest ISO mitigation plan and the mitigation plan previously proposed but not accepted in the initial ASM proposal has no bearing on our determination here. Furthermore, we note that, in the initial ASM proceeding, the IMM explained that suppliers can become pivotal suppliers of operating reserves in local areas and, therefore, may have substantial market power.[40] This statement is consistent with the findings of the market power study and may account for the mitigation plans' similarities.

51. As explained in the February 25 Order, we will not require the Midwest ISO to apply its mitigation measures on a market-wide basis when constraints are not binding.[41] The market power analysis found that the ASM will be competitive on a market-wide basis when transmission constraints are not binding. The regulation market has pivotal suppliers for the entire Midwest ISO region on such an infrequent basis that such conditions would not be sufficiently predictable to allow the successful exercise of market power.[42] The market power analysis' finding that such conditions occur most

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[37] *Citing ISO New England, Inc.*, 104 FERC ¶ 61,039, at P 19 (2003).

[38] Midwest TDUs cite and quote the Kirsch Affidavit extensively in their pleadings regarding the market power analysis and mitigation plan, and Dr. Kirsch's arguments and evidence are refuted as part of Midwest TDUs' corresponding arguments.

[39] February 25 Order, 122 FERC ¶ 61,172 at P 89.

[40] *See* Midwest ISO February 15, 2007 Filing, Docket No. ER07-550-000, Patton Affidavit at 17.

[41] February 25 Order, 122 FERC ¶ 61,172 at P 90.

[42] *See* Market Power Study at 23.

frequently during winter *months* does not suggest that suppliers will be able to predict whether they will be pivotal during specific *hours*. Even if such a supplier could accurately predict that it would be pivotal, it will have the incentive to exercise its market power only if it has sufficient capability in the market that it can benefit from the resulting higher prices.[43] Therefore, we deny rehearing. Midwest TDUs have not identified specific, structural problems sufficient to justify the imposition of mitigation on a market-wide basis when constraints are not binding.[44]

### 2. Mitigation Thresholds

#### a. February 25 Order

52. The Commission accepted the Midwest ISO's mitigation approach, which provides that an offer is mitigated if it fails both the conduct and impact tests. An offer fails the conduct test if any part of the offer exceeds its corresponding reference level by an amount greater than the applicable conduct threshold. The Commission accepted Midwest ISO's proposed economic withholding threshold of the lower of $50 per MWh or 300 percent of the reference level. However, the Commission directed the Midwest ISO to submit tariff revisions to lower the conduct threshold for economic withholding to $10 per MWh during an initial, transitional period and to include a ratcheting mechanism to incrementally increase the threshold.[45]

53. Specifically, the Commission required that the economic withholding threshold be the lower of $10 per MWh or 300 percent of the reference level at market start. Every 90 days thereafter, the threshold will increase by $10 increments until $50 per MWh is reached unless the IMM finds market behavior that warrants keeping the threshold constant for the next 90 days. The Commission required the IMM to file, 30 days prior to the end of each quarter, a quarterly report indicating whether market power is being appropriately mitigated and whether the next scheduled $10 per MWh increase should occur. In the event that the IMM recommends keeping the threshold constant in its report, the Commission will issue an order that, based on the IMM's report(s) and parties' comments, determines whether to reinstate the incremental increases upon the expiration of the following 90-day period. This will delay the increase in the thresholds to allow the

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[43] *See id*.

[44] We note that section 53.3 requires the IMM to refer to the Commission any behavior to exercise market power in violation of the tariff, if the tariff does not provide an explicit remedy.

[45] February 25 Order, 122 FERC ¶ 61,172 at P 122-23.

Commission to determine whether a further increase is warranted and to consider the views of all interest parties.[46]

### b. Requests for Rehearing

54. On rehearing, Midwest TDUs reiterate their prior argument that the threshold of the lesser of $50 per MWh or 300 percent of the reference level at market start is unjust and unreasonable because it is too high and will cause under-mitigation. According to Midwest TDUs, the threshold addresses only the most egregious exercises of market power because it allows suppliers to legally offer the lesser of 299 percent or $49.99 per MWh above their respective reference levels and raise market prices by $49.99 per MWh without triggering mitigation. They assert that similar mitigation thresholds used in the New York ISO were too high to mitigate substantial offer price increases.[47] Midwest TDUs assert that marginal cost uncertainty does not merit such a high threshold and sellers will offer well above their marginal costs not because of such uncertainty but because they can do so without exceeding the permissive mitigation threshold. They add that the IMM has agreed, in other contexts, that generous thresholds may give sellers with locational market power incentives to raise their offers and thereby allow the potential exercise of market power.[48]

55. In response to the IMM's analysis of the magnitude of withholding needed to generate a profitable price spike, Midwest TDUs reiterate in their argument on rehearing that the IMM did not examine price impacts but rather the amount of withholding needed to cause the market to reach a shortage.[49] Midwest TDUs explain that prices can reach uncompetitive levels without resulting in a shortage.[50] They assert that, if the market's excess capacity could or would be dispatched only above a supra-competitive price, that capacity would not be an effective restraint on the exercise of market power. In addition, Midwest TDUs contend that the IMM appears to have considered how much capacity

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[46] *Id*.

[47] Citing *2006 State of the Market Report: New York ISO* at 40-41, July 2007.

[48] Citing Midwest ISO Independent Market Monitor's Jan. 22, 2008 Informational Report on Effectiveness and Need for Changes in Narrow Constrained Area Designations, Docket No. ER07-235-000, at 10-12.

[49] Midwest ISO and IMM Joint Comments on Technical Conference, Docket Nos. ER07-1372-000 and ER07-1372-001, at 9-10.

[50] *Midwest Indep. Transmission Sys. Operator, Inc.*, 105 FERC ¶ 61,147, at P 56 (2003).

would need to be withheld to create a deficiency, rather than how much must be withheld to raise prices above competitive levels. They argue that the IMM should have considered the costs of any excess capacity to predict whether the owner of the capacity would respond to a price increase and whether any of the capacity is owned by a competing supplier with an incentive to defeat the price increase, consistent with the Commission's Merger Policy Statement.[51]

56. Midwest TDUs contend that the mitigation thresholds should be lowered to $7.50 per MWh, similar to those in PJM, because a lower threshold more accurately reflects the uncertainty associated with the calculation of a unit's reference levels. They argue that reference levels established under competitive conditions represent a seller's own perception of its costs and risks, thereby preventing the IMM from inappropriately mitigating offers by replacing them with reference levels that are lower than the seller's marginal costs under both competitive and noncompetitive conditions.[52] According to Midwest TDUs, $7.50 per MWh is a reasonable estimate of the amount of uncertainty regarding whether reference levels accurately reflect generators' marginal costs.[53] In contrast, they claim that the $50 per MWh threshold far exceeds the allowance needed to reflect such uncertainty and is instead a license to exercise market power. Midwest TDUs note that the IMM acknowledged that the proposed $50 per MWh threshold is "arbitrary but not capricious" and argue that the IMM has not produced any empirical evidence to measure the degree of uncertainty associated with approximating units' marginal costs using reference levels and to justify its proposed threshold. They also argue that marginal cost uncertainty is less applicable in the case of contingency reserves because the price of reserves should be equal to the opportunity cost of not providing energy or regulating reserves.

57. Midwest TDUs argue that the $7.50 per MWh threshold would not cause over-mitigation because it would allow fixed cost recovery and avoids the IMM's concerns about "cost-based" approaches to mitigation. They explain that sellers can recover their fixed costs when they are infra-marginal and receive revenues in excess of their marginal

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[51] *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, 61 Fed. Reg. 68,595, 68,607 (Dec. 30 1996), FERC Stats. & Regs. ¶ 31,044 (1996).

[52] They note that the market design already accounts for uncertainty regarding changes in fuel and opportunity costs because reference levels are adjusted for fuel changes and the simultaneous co-optimization software automatically adds actual opportunity costs to the seller's ancillary services offers.

[53] Midwest TDUs note that PJM has determined that $7.50 per MWh provides a reasonable allowance for marginal cost estimation error.

costs and when they receive scarcity rents under shortage conditions. Midwest TDUs add that many generation resources already recover their fixed costs by including such costs in their retail or wholesale rate base and via capacity charges set forth in long-term contracts. Midwest TDUs contend that the IMM's reference level determination process avoids concerns regarding the improper calculation of cost-based rates and that opportunities to recover fixed costs should ensure that new suppliers enter the market. They add that a similar approach used in PJM did not contribute to generator exit or lack of entry.[54]

58. With regard to the transitional economic withholding threshold, Midwest TDUs argue that the Commission should permanently set the threshold at $10 per MWh and should not have built a ratcheting mechanism into the economic withholding threshold. According to Midwest TDUs, sellers will exercise market power under the ratcheting approach by increasing their offers each quarter as the threshold increases and refraining from submitting offers that exceed their reference levels by the threshold amount that would trigger mitigation. They argue that the Midwest ISO or IMM will not request a constant or lower mitigation threshold when needed because the IMM mistakenly believes that the absence of mitigation reflects competitive market conditions and does not recognize that suppliers may exercise market power without exceeding the economic withholding threshold. They contend that the mitigation threshold should stay at $10 per MWh and the Midwest ISO may propose and justify any needed threshold increases in future filings.[55]

59. If the Commission retains the ratcheting mechanism, Midwest TDUs contend that the Commission should establish standards to determine whether the economic withholding threshold should rise. Midwest TDUs believe that the IMM is unlikely to find behavior to warrant a threshold below $50 per MWh because the IMM supports the $50 per MWh threshold. They argue that the Commission should identify meaningful criteria for the IMM to assess whether market behavior warrants keeping the threshold constant. Specifically, Midwest TDUs request that the IMM track whether sellers increase their offers after the threshold rises. If sellers increase their offers under a new, higher threshold (as compared to their offers submitted under the previous, lower threshold) without triggering mitigation, then the Commission should maintain the lower threshold to protect consumers.

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[54] PJM Interconnection, Inc., *2006 State of the Market Report, section 6*, *available at* http://www2.pjm.com/markets/market-monitor/downloads/mmu-reports/2006-som-volume-ii-section6.pdf.

[55] In such future filings, they state that the Commission should require the Midwest ISO to provide evidence that the $10 per MWh threshold prevents sellers from reflecting the marginal cost uncertainty they face.

60. Similarly, Dynegy requests clarification regarding the ratcheting mechanism. It argues that the Commission should provide guidance regarding the factors the IMM should consider when determining whether to recommend delays in incremental increases in the threshold. Dynegy requests that the Commission clarify how the scheduled threshold increases will be implemented and how it will avoid unfairly mitigating areas where market power is not an issue in the event that the IMM reports differing market behavior findings across different zones.

61. While Dynegy agrees with the Commission's finding that the $50 per MWh threshold is appropriate, it contends that the initial $10 per MWh threshold for economic withholding with incremental ratcheting is unjust and unreasonable because it does not appropriately balance the risks of over-mitigation and under-mitigation. Dynegy explains that, even if the IMM reports that market power is being appropriately mitigation and the thresholds increase every 90 days, it will take a minimum of a year to reach the $50 per MWh threshold. Dynegy is concerned that this transitional mechanism is overly conservative, will result in over-mitigation, and may not permit generators to receive adequate compensation. It adds that, in combination with the 4-percent tolerance band, increased penalties, and unknown revenue sufficiency guarantee (RSG) charges, this transitional mechanism will fail to provide proper incentives to market participants and may thereby discourage participation in the market. In order to avoid these unintended negative consequences, Dynegy argues that the Commission should require the IMM to follow a more expeditious schedule to reach the $50 per MWh threshold.

### c. <u>Commission Determination</u>

62. We will deny the rehearing requests with respect to the mitigation thresholds. As explained in the February 25 Order, we are requiring the Midwest ISO to begin with a $10 per MWh economic withholding threshold at ASM launch, and to incrementally increase the threshold on a quarterly basis unless the IMM finds that increased thresholds inadequately mitigate market power. This transitional mechanism should alleviate Midwest TDUs' concerns by demonstrating either that the $50 per MWh threshold appropriately mitigates market power or, in the alternative, that market behavior warrants the adoption of a lower threshold.[56] Based on the current record, however, Midwest TDUs have not demonstrated that the $50 per MWh threshold is unjust and unreasonable.

63. We find that the $50 per MWh conduct threshold strikes an appropriate balance between the need to protect consumers from the exercise of market power and the goal of

[56] If Midwest TDUs are correct that the initial threshold of $10 per MWh is essential to prevent the exercise of market power without over-mitigating the market, then the IMM should be able to provide persuasive evidence supporting such a threshold in a subsequent quarterly report.

avoiding over-mitigation that may keep capacity out of the market.[57] This mitigation threshold is identical to the economic withholding threshold applied to operating reserve offers in New York ISO and is similar to the economic withholding thresholds used in the energy markets of the Midwest ISO, New York ISO, and ISO-New England. We are concerned that the significantly lower threshold of $7.50 per MWh that Midwest TDUs argue for in their rehearing request may cause over-mitigation, resulting in the unfair mitigation of offers that reflect legitimately higher costs, and in penalizing suppliers that try to resolve constraints.[58] If the IMM determines that the $50 per MWh threshold is too high to mitigate the exercise of market power, as Midwest TDUs suggest, then the Midwest ISO can submit proposed tariff revisions requesting that the threshold decrease.

64. The IMM has sufficiently clarified its method of determining whether "fair game" behavior has occurred in its quarterly reports regarding incremental threshold increases. As part of its report, the IMM stated that it will determine whether suppliers have been able to evade the mitigation measures and significantly affect market outcomes by raising their ancillary services offers by an amount that is near to, but does not exceed, the conduct threshold.[59] No party has argued that the IMM's method is inappropriate, and we find that this method will be sufficient to detect any gaming of the ratcheting mechanism and prevent undue discretion by the IMM to determine what must be included in its quarterly reports.

65. We will not expedite the schedule for quarterly threshold increases. It is important that each threshold apply for a sufficient period to allow the IMM to assess market behavior. If each threshold instead applies over a period shorter than 90 days, as Dynegy requests, we are concerned that market participants may temporarily restrain their behavior in order to increase the thresholds. Furthermore, we expect that, while the lower transitional thresholds are not optimal, they should not prevent generators from receiving adequate compensation or discourage participation in the ASM. Each generation resource should be able to receive adequate compensation because the IMM

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[57] We will not require Midwest ISO to submit further 205 filings to propose incremental increases above the $10 per MWh initial threshold, as Midwest TDUs argue for in their rehearing request, because we find that the final $50 per MWh threshold is appropriate.

[58] *See* February 25 Order, 122 FERC ¶ 61,172 at P 121.

[59] Specifically, the IMM stated that it will perform a conduct test on offers at a threshold level that is somewhat lower than the mitigation threshold and a market impact test that estimates the market impacts of mitigating such offers. If the market impacts are material, the IMM will recommend that the threshold should not be increased. *See id.* P 104, n.50.

will establish an appropriate reference level that reflects the unit's estimation of its marginal costs, opportunity costs, and legitimate risks and is adjusted to reflect fuel cost changes. If these costs were to significantly change, such that the lower economic withholding thresholds may unfairly mitigate legitimate offers, market participants may consult the IMM to request and support an adjustment to their reference level.[60]

### 3. Reference Levels

#### a. February 25 Order

66. The Commission conditionally accepted the Midwest ISO's proposal to use the existing provisions of section 64.1.4 for its energy market to determine unit-specific reference levels in the ASM, subject to further modifications in a subsequent compliance filing.[61] In the Midwest ISO, conduct thresholds are added to reference levels for an individual generator to determine if it is behaving competitively. Reference levels are based upon estimates of a generator's marginal costs, including legitimate risks and opportunity costs. The tariff sets three methods (in order of application) for calculating a unit's reference levels: (1) offer-based,[62] (2) price-based,[63] and (3) consultative.[64] 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,[65] or an attempt to determine a reference level in

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[60] The Commission will determine an appropriate response in a subsequent order in the event that the IMM submits an adverse quarterly report that finds differing market behavior across different zones.

[61] *See id.* P 137.

[62] 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.

[63] The price-based method uses the mean of the market clearing price 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.

[64] 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.

[65] Consultations to determine a unit's reference level must occur prior to the conduct being examined.

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.

67. The Commission required the Midwest ISO to work with its stakeholders and provide additional clarification and documentation, as appropriate, regarding the IMM's process to determine a generation resource's initial reference level in its Business Practices Manuals.[66] When the market begins operation, there will be no history of accepted offers or market clearing prices. Thus a transitional mechanism for the determination of appropriate reference levels will be needed. As provided in the tariff, the IMM will develop a consultative reference level for each supplier. For units that do not submit appropriate 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. Requests for Rehearing

68. OMS argues on rehearing that the consultative process for setting reference levels lacks the clarity, transparency, and formal regulatory oversight needed to restrain generating companies and prevent the IMM from exercising undue discretion. According to OMS, the tariff does not have any constraints on the information generating companies can submit during IMM consultations or benchmarks for the IMM to assess the accuracy of a unit's proposed reference levels. It adds that the tariff does not define key terms, such as "legitimate risks and opportunity costs" and "[r]eference [l]evels," that could otherwise create boundaries necessary for the process to work properly. OMS is especially concerned that the IMM will exclusively use this process to determine reference levels during the initial 90-day period following ASM launch. In addition, OMS states that the offer-based and price-based methods of setting reference prices also exhibit vagueness and a lack of transparency and oversight.

69. OMS argues that the Commission has expressed concern regarding the transparency of RTOs and undue IMM discretion in other contexts. It notes that in the February 25 Order the Commission required the IMM to clarify its process for auditing generating companies to detect physical withholding and took steps to reduce the IMM's discretion.[67] In contrast, OMS argues that the Commission has not remedied the consultative process for determining reference levels despite its importance, lack of transparency, and potential for undue IMM discretion.

[66] *See id.* P 138.

[67] *See id.* P 122, 151.

70. OMS recommends the development of a formalized approach for evaluating the accuracy and appropriateness of reference levels and argues that the Commission should require the IMM to report its reference level determination process and findings to the Commission and OMS for review. It contends that there are no established mechanisms for the Commission and state regulators to oversee the IMM's reference level determination process or findings. OMS explains that state regulators are well-suited to review the reference price-setting process and the reference prices determined by the IMM because state regulators are unbiased, act in pursuit of the public interest, and have extensive expertise and historical experience in assessing and determining energy companies' prudent costs. OMS adds that state regulators have a significant interest in the establishment of accurate reference levels to prevent retail customers from paying inflated prices and to ensure that generators receive adequate revenues.

71. OMS concludes that the Midwest ISO's policy that limits state regulators' access to confidential IMM data must be modified in order to improve the oversight of the IMM's reference level determinations and prevent undue IMM discretion. OMS understands that the data involved in the reference level determination process is sensitive and notes that state regulators have experience in properly handling such highly confidential data. OMS argues that the Midwest ISO's tariff limits the ability of many state commissions to receive or view data underlying reference levels or even the reference levels themselves. It adds that, without access to such data, state commissions cannot effectively exercise their FPA section 206 complaint rights regarding the IMM's reference level determinations.

#### c. <u>Commission Determination</u>

72. We deny OMS' rehearing request with respect to the IMM's discretion in determining reference levels in the ASM and the need for additional Commission oversight. As the Commission explained in the February 25 Order, the IMM's reference level determination process is the same process currently applied in the Midwest ISO's energy market and is similar to the processes used in New York ISO and ISO New England.[68] While the IMM must consult market participants to collect data, the IMM makes its own, independent determinations using the specific methods outlined in the tariff.[69]

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[68] *See id.* P 137.

[69] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163, at P 306 (TEMT II Order), *order on reh'g*, 109 FERC ¶ 61,157 (2004) (TEMT II Rehearing Order), *order on reh'g*, 111 FERC ¶ 61,043; *reh'g denied*, 112 FERC ¶ 61,086 (2005), *aff'd sub nom. Wisc. Pub. Power, Inc. v. FERC*, 2007 U.S. App. LEXIS 17257, No. 04-1414 (D.C. Cir. 2007).

73. However, we grant rehearing with respect to the Midwest ISO's reference level determination process. We will require the Midwest ISO to work with its stakeholders to provide additional clarification regarding the Midwest ISO's reference level determination process, including information regarding the types of data and calculation method(s) used when establishing reference levels using the consultative process.[70] To communicate the outcome of this stakeholder process to the Commission, we will require the Midwest ISO to submit, in a compliance filing due within 30 days of the date of this order, tariff revisions to section 64.1.4 to clarify its reference level determination process, or, in the alternative, a statement explaining why such revisions are unnecessary. In addition, we note that OMS may choose to file a complaint, pursuant to section 206 of the FPA, if it determines that the reference level determination process or specific reference level determinations are unjust and unreasonable.

74. As for OMS' requested review of the IMM's reference level determination process and specific reference level findings, we deny rehearing and will not grant state commissions additional data access or oversight authority.[71] The IMM's reference level determination procedures and access to confidential data were already addressed by the Commission in a prior proceeding where it accepted the Midwest ISO's energy market proposal.[72] We find that the OMS' request for access to confidential reference level data is an impermissible collateral attack on that proceeding.

### 4. Automated Mitigation Procedures

#### a. February 25 Order

75. In the February 25 Order, the Commission accepted Midwest ISO's proposal to apply mitigation procedures manually rather that automatically in the ASM. The Commission found that manual mitigation will appropriately mitigate the exercise of market power in the ASM. The Commission also recognized, however, that an automated mitigation program (AMP) may improve the performance of the Midwest ISO's mitigation measures by shortening any time lag associated with manual mitigation. The Commission expressed concern that requiring implementation of an AMP at market

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[70] We note that the Midwest ISO states that it will work with its stakeholders to provide additional information regarding its reference level determination process. *See* Midwest ISO, March 26, 2008 Compliance Filing, Docket No. ER07-1372-004 at 4.

[71] In accordance with section 38.9.4, state commissions may be able to access confidential information if such data is necessary for them to fulfill their statutory duties.

[72] *See* TEMT II Order, 108 FERC ¶ 61,163, TEMT II Rehearing Order, 109 FERC ¶ 61,157, *order on reh'g and offer of proof*, 111 FERC ¶ 61,448 (2005).

start could delay the start of the ASM or interfere with initial reference level determinations. For these reasons, the Commission required the Midwest ISO to implement automated mitigation in the ASM as soon as possible in the 90 days following the start of the ASM and directed it to submit a plan to implement automated mitigation measures in a subsequent compliance filing. In addition, the Commission required the IMM to monitor market behavior and submit a report to the Commission in the event that it determines that manual mitigation is not effectively inhibiting the exercise of market power.[73]

### b. Requests for Rehearing

76. Midwest Transmission Customers argue on rehearing that the Commission should require the Midwest ISO to implement an AMP at the start of the ASM to ensure appropriate mitigation. They contend that when manual mitigation was previously used in the day-ahead energy market, there was a one day time lag in the application of mitigation. For example, they assert, an exercise of market power on day one would not be mitigated; instead, such conduct would trigger mitigation on day two if the behavior continued. Midwest Transmission Customers contend that the Commission should not permit the Midwest ISO to give market participants a one-day free pass that would *by design* allow market power to be exercised.[74] They add that the effects of unmitigated market power would be particularly acute in zonal markets that demonstrate extraordinary market concentrations. If the Commission does not require the Midwest ISO to have an AMP at market-start, Midwest Transmission Customers request that the Commission direct the Midwest ISO to correct any misconduct on an after-the-fact basis to prevent a gap in the screening of offers.

77. Midwest Transmission Customers contend that requiring an AMP at market-start should not delay the launch of the ASM. Midwest Transmission Customers note that the February 25 Order required the Midwest ISO to implement an AMP no later than 90 days after the June 1, 2008 ASM launch date. They conclude that requiring an AMP at market-start should not cause any delays because the ASM launch date has been delayed until September 9, 2008, which would provide more than the 90-day period initially given to implement an AMP.

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[73] February 25 Order, 122 FERC ¶ 61,172 at P 177-78.

[74] They explain that, contrary to the energy market, customers cannot protect themselves against the exercise of market power in the day-ahead market by shifting their demand to real-time because all of the required contingency and regulating reserves must be acquired in the day-ahead market.

### c. **Commission Determination**

78. In the February 25 Order, the Commission required the Midwest ISO to "implement automated mitigation in the ASM *as soon as possible* in the 90 days following the start of the ASM."[75] We agree that, if possible, the Midwest ISO should implement its automated mitigation procedures at the launch of the ASM. However, we will deny the rehearing request and will not specifically require the Midwest ISO to employ automated mitigation measures at market start, in the event that such immediate implementation could delay the start of the ASM or adversely affect the application of mitigation.[76]

79. As explained in the February 25 Order, we will permit the Midwest ISO to employ manual mitigation measures if it is unable to implement an AMP at market start. Manual mitigation will appropriately mitigate the exercise of market power, consistent with the manual mitigation measures previously applied in the Midwest ISO day-ahead energy market. We also recognize that manual mitigation may be important during an initial period following market start to allow the IMM to consult with market participants regarding initial reference level determinations.[77]

80. We will grant Midwest Transmission Customers' argument on rehearing that manual mitigation may contribute to a time lag in the prospective application of mitigation. We will require the Midwest ISO to correct any misconduct on an after-the-fact basis or, if such corrections are not possible, to refer behavior that violates the Midwest ISO's tariff to the Commission, in accordance with section 53.3 of its tariff.

### 5. **Mitigation of Demand Response Resources**

81. Demand Response Resources (DRRs) are divided into two categories: DRRs-I and DRRs-II. DRRs-I are resources hosted by an energy consumer or load serving entity that are capable of supplying a *specific quantity* of energy or contingency reserve, at the choice of the market participant, to the energy and operating reserve market through physical load interruption. DRRs-II are resources hosted by an energy consumer or load serving entity that are capable of supplying a *range* of energy and/or operating reserve, at the choice of the market participant, to the energy and operating reserve market through behind-the-meter generation and/or controllable load.

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[75] February 25 Order, 122 FERC ¶ 61,172 at P 177-78.

[76] *Id.*

[77] *Id.*

### a. February 25 Order

82. The Commission accepted the Midwest ISO's proposal to provide hourly offer caps of $1,000 per MWh for DRRs-I providing contingency reserves in the real-time and day-ahead energy and operating reserve markets. These caps are identical to the contingency reserve offer caps for generation resources and DRRs-II. The Commission required the Midwest ISO, in its compliance filing, to extend the $1,000 per MWh offer cap to the hourly curtailment offers of DRRs-I in a manner comparable to other resources, in order to prevent them from exercising market power to extract excessive make-whole payments. The Commission also directed the Midwest ISO to explain whether the hourly curtailment offers of DRRs-I can be split into their component energy and no-load equivalents in order to apply the offer cap to only the energy offer portion.[78]

### b. Requests for Rehearing

83. Midwest Transmission Customers contend that the Commission's decision to extend offer caps to DRRs-I is arbitrary and capricious. They argue that the Commission extended offer caps to such resources based on an incorrect assumption that DRRs-I could raise prices above scarcity levels; they explain that DRRs-I are not dispatchable and, therefore, cannot set market prices. Midwest Transmission Customers also maintain that, if the Midwest ISO elects to commit a DRR-I, then that resource must be the least costly and most economic resource available to the market, even if its offer is above the $1,000 cap or contributes to high levels of uplift costs. They add that it may be far less expensive to pay uplift costs to a small population of DRRs-I that offer in excess of the cap if the alternative involves market-wide scarcity pricing as a result of triggering a contingency reserve shortage.

84. In addition, Midwest Transmission Customers contend that the offer cap fails to recognize the legitimate costs of DRRs-I. They explain that, unlike generation resources, the marginal costs of DRRs do not consist largely of fuel. Instead, curtailing usage may involve sending workers home and incurring lost profits that far exceed the marginal cost of electricity. They add that evidence has been presented to the Commission in another Midwest ISO proceeding that indicates that there are existing DRRs with costs approaching $4,500 per MWh.[79]

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[78] *Id.* P 190.

[79] *See* Madison Gas & Electric Company, January 22, 2008 Protest, Docket No. ER08-404-000 at 3-4.

#### c. Commission Determination

85. We deny the Midwest Transmission Customers' argument on rehearing that the extension of offer caps to DRRs-I is arbitrary and capricious. As explained in the February 25 Order, we are requiring the Midwest ISO to extend the $1,000 per MWh offer cap to the hourly curtailment offers of DRRs-I in order to prevent them from exercising market power to extract excessive make-whole payments.[80] We recognize, as Midwest Transmission Customers argue, that DRRs-I do not set market prices and may face marginal costs that differ significantly from generation resources. However, our decision is not arbitrary and capricious because the $1,000 offer cap is currently applicable to DRRs-II and generation resources, and we find that DRRs-I should be subject to the offer cap in a comparable manner. We note that other parts of DRR-I offers are already subject to hourly offer caps for providing contingency reserves.

86. In response to Midwest Transmission Customers' argument on rehearing regarding the offer cap's failure to recognize the legitimate costs of DRRs-I, we disagree and note that the Commission recently discussed the same cost data supplied by Madison Gas and Electric.[81] In that proceeding, the Commission stated that the provisions in the Midwest ISO's tariff are not intended to prevent participation in any state-approved load control programs or restrict rate recovery from retail customers.

## D. Tolerance Band and Excessive/Deficient Energy Charge

### 1. February 25 Order

87. In the February 25 Order, the Commission accepted the Midwest ISO's proposal to use a tolerance band of +/- four percent around the average telemetered output of a resource for the sum of the current dispatch interval and the previous dispatch interval. The Commission accepted the proposal for a tolerance band because it found that the Midwest ISO struck a reasonable balance between respecting the physical operating limitations of resources and minimizing the incentive to "free-ride" on the collective resources of the market.[82]

88. For resources that deviate from the dispatch instructions beyond the tolerance band in three successive dispatch intervals, the Commission accepted a penalty provision

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[80] *See* February 25 Order, 122 FERC ¶ 61,172 at P 190.

[81] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 123 FERC ¶ 61,070, at P 26 (2008).

[82] *See* February 25 Order, 122 FERC ¶ 61,172 at P 255-57.

entitled the Excessive/Deficient Energy Charge to replace the current Uninstructed Deviation Penalty. Any credits collected from this charge will be allocated to all market participants based on a load ratio share basis, excluding their export schedules. The excessive energy threshold is adjusted so that it is no less than 6 MW or no greater than 20 MW plus the sum of the average dispatch targets for energy for the current and previous dispatch interval and the average regulating reserve deployment instruction. The Midwest ISO explained that it did not believe sufficient financial incentive to follow dispatch instructions would be created by basing the charge only on the amount of energy beyond the tolerance band and the Commission agreed with this approach.[83]

### 2. Requests for Rehearing

89. Dynegy requests rehearing of the Commission's approval of a +/- four percent tolerance band. Dynegy disputes that the four percent tolerance band is reasonable, a compromise proposal, and flexible enough to allow resources to follow dispatch instructions without penalty. Dynegy asserts that a four percent tolerance band is overly restrictive, unsupported and will potentially raise prices to customers. Furthermore, Dynegy argues the Commission failed to address the difference between the Midwest ISO's four percent tolerance band and PJM's ten percent tolerance band. Dynegy asks the Commission to require the Midwest ISO to submit a report evaluating the tolerance band after 90 days of market operation, instead of the 180-day report directed in the February 25 Order.

90. Duke requests rehearing of the Commission's acceptance of the Excessive/Deficient Energy Charge based on the entire amount of energy injected. Duke asserts that basing the charge on the total amount of energy injected results in penalties that are not proportionate to the impact to the market and beyond what are necessary to provide a disincentive to deviate from dispatch instructions. Duke states that it is not challenging the Commission's finding that applying the deviation to only the number of MW outside the tolerance band is not sufficient disincentive, but Duke instead argues for proportionality to the amount of over or under-generation. Duke requests that Midwest ISO be directed to revise its penalty such that it will cover the amount of any additional regulation costs and provide a proportionate disincentive to deviations.

91. Likewise, Ameren requests rehearing of the Commission's decision to accept an Excessive/Deficient Energy Charge based on the total amount of energy injected. Ameren asserts that this decision unduly discriminates against market participants selling energy from large generating units and is not reasoned decision-making. Ameren provides an example of a 105 MW facility with total injections of 101 MW and a 605 MW facility with total injections of 601 MW over an operating hour, both producing 1

[83] *Id.* P 269.

MW outside the tolerance band. Ameren states that although their deviation is the same, 1 MW, the larger unit will pay a penalty six times as large. In addition, Ameren notes that the excessive/Deficient Energy Charge is meant to replace the Uninstructed Deviation Penalty, and the Uninstructed Deviation Penalty only applied to the amount outside the tolerance band. Therefore, Ameren asserts that to be consistent, the Excessive/Deficient Energy Charge should also only apply to amount outside the tolerance band.

92. Hoosier and Southern Illinois also question the rationale of having a penalty based on the actual injection amount. Hoosier and Southern Illinois believe that this violates the principle of cost causation in ratemaking.

### 3. Commission Determination

93. We are not persuaded that a change in the tolerance band is needed and, therefore, we deny rehearing. As we stated in the February 25 Order, the tolerance band of plus or minus four percent is a reasonable amount of tolerance around dispatch instructions and the additional constraint that three consecutive dispatch intervals must be violated to trigger the penalty provisions is reasonable as well.

94. We disagree with arguments that the Commission did not address the difference between PJM's tolerance band of 10 percent and the Midwest ISO's tolerance band of 4 percent. In the February 25 Order, the Commission noted the difference, but stated that it was within the Midwest ISO's section 205 rights to propose its own tolerance band number given that there is no industry standard number.[84] We also note that the Commission directed the Midwest ISO to evaluate empirical data on violations of the tolerance band that invoke the Excessive/Deficient Energy Charges and report on the results within 180 days of the start of the ASM.[85] In the February 25 Order, the Commission stated that the Midwest ISO may file prior to 180 days if it determines an immediate need for a revision to the tolerance band.[86] At present, however, we do not have any data or other reason to conclude that a four percent tolerance band will unreasonably subject resources to penalties that are otherwise acting in good faith to comply with their dispatch instructions.

95. Likewise, we deny rehearing in regard to the Excessive/Deficient Energy Charge. The purpose of the charge is to provide a reasonable disincentive to repeated deviations

[84] *Id.* P 256.

[85] *Id.* P 257.

[86] *Id.*

from dispatch instructions that are beyond the tolerance band. The Midwest ISO's Excessive/Deficient Charge rate is intended to deter market participant behavior and, therefore, is not intended to only reflect the cost of the deviation. Therefore, we are not persuaded by arguments citing cost causation principles. We believe that a charge based on the total amount injected accomplishes this objective without being so punitive as to be onerous.

96. We also disagree with arguments that a deviation of 1 MW outside the tolerance band should be treated the same, regardless of the amount of the dispatch instruction. We set forth a simplified example to explain our rationale.[87] A 150 MW dispatch instruction with a four percent tolerance band is given a 6 MW tolerance band. If that resource deviates by the 1 MW mentioned beyond the tolerance band by producing 143 MW, and does it for three consecutive dispatch intervals (the minimum needed to invoke the charge), the impact from the system operator's perspective is not 1 MW, it is a shortfall of 7 MW multiplied by three dispatch intervals or 21 MW. Continuing the same 1 MW deviation example, now it is a 500 MW dispatch instruction with a tolerance band of four percent or 20 MW.[88] If this resource deviates by 1 MW beyond the tolerance band by producing 479 MWs, the shortfall from the system operator's perspective is the 21 MW shortfall multiplied by the three consecutive dispatch intervals needed to invoke the charge or 63 MW. Therefore, a 1 MW deviation is not simply a 1 MW deviation as commenters have suggested and we do not find that it is appropriate to treat it as such.

97. We do not agree with arguments that, because the Excessive/Deficient Energy Charge is intended to replace the Uninstructed Deviation Penalty, it should operate in a substantially similar manner. The Excessive/Deficient Energy Charge does replace the Uninstructed Deviation Penalty, but that penalty only applied to energy deviations. This penalty will apply to both energy and regulation deviations, the Midwest ISO will operate as the Reliability Coordinator (RC) and Balancing Authority, and there will not be a permanent must offer for regulation service.[89] It is essential for the efficient and reliable operation of the system, that the Midwest ISO has reasonable assurances that market

[87] We note that the Midwest ISO filed a complete example calculation of the Excessive/Deficient Energy Charge on compliance. *See* Midwest ISO Transmittal Letter at 11-12.

[88] We note that we selected dispatch instructions of 150 MW and 500 MW because the four percent tolerance band produces 6 MW and 20 MW, which are the minimum and maximum adjustments to the Deficient Energy Threshold.

[89] *See* NERC Transmission Loading Relief Procedure, *available at* http://www.nerc.com/~filez/Logs/relcoors.htm.

participants will comply with their dispatch instructions and this charge is one such mechanism.

### E. Must Offer

#### 1. February 25 Order

98. In the February 25 Order, the Commission accepted a 180-day must offer requirement for regulating reserves and a permanent requirement for network resources to offer contingency reserves. The contingency reserve must offer works in conjunction with the energy must offer specified in Module E, which details resource adequacy requirements.[90]

#### 2. Requests for Rehearing

99. The Midwest TDUs assert that the Commission erred by not requiring the IMM to assess the effect of eliminating the must-offer requirement for regulation as part of its physical withholding audits and reporting that it is already required to do. The Midwest TDUs request a report 6 months after the regulation must-offer requirement expires that assesses whether the Midwest ISO should reinstate a regulation must-offer requirement based on the robustness and liquidity of the regulation market.

#### 3. Commission Determination

100. We will deny rehearing. We expect that the IMM will review the regulation market and do not believe that a separate report is needed for the regulation market after the expiration of the must-offer requirement. The Midwest ISO's IMM already publishes an annual State of the Market report, which includes details about the competitiveness of all markets administered by the Midwest ISO. We expect that similar to other regional market's reports, such as PJM, the IMM for the Midwest ISO will detail the competitiveness of the market for regulating reserves.[91] The IMM also has general rights applicable to all markets to conduct random audits of units suspected of physical withholding, which were conditionally accepted subject to clarification in the

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[90] We note that the Commission accepted a filing by the Midwest ISO regarding a revised Module E on March 26, 2008. *See Midwest Indep. Transmission Sys. Operator*, 122 FERC ¶ 61,283, at P 201 (2008).

[91] *See PJM 2007 State of the Market Report* at 276, *available at* http://www2.pjm.com/markets/market-monitor/downloads/mmu-reports/2007-som-volume2.pdf.

February 25 Order.[92] The Midwest ISO clarified its audit process on compliance[93] and those changes are discussed in the order on the Midwest ISO's compliance filing, being issued concurrently with this order.[94] These provisions are sufficient and reasonable to monitor the markets and promulgate information about the performance of the markets and additional reporting requirements are not needed at this time.

### F. Scarcity Pricing

#### 1. February 25 Order

101. The Commission found the Midwest ISO scarcity pricing proposal to be reasonable, noting that the Midwest ISO method is one of the four methods identified in the Competition NOPR[95] that allows the market price to better reflect value of lost load (VOLL) in emergency situations.[96] The Commission based its acceptance of the scarcity pricing provisions on its finding that the Midwest ISO has developed measures to monitor and mitigate market power that could artificially drive prices to scarcity levels, including procedures to mitigate physical withholding. The Commission also found that the emergency procedures and corresponding short-term price signals will reasonably encourage resources to participate in the market.

#### 2. Requests for Rehearing

102. The Midwest TDUs contend that the VOLL and the revenue produced by the resulting clearing prices do not reflect payments that load already makes and revenues sellers already receive for resource adequacy payments such as fixed-cost recovery of generation in rate base and long-term contracts. By ignoring other sources of fixed-cost recovery, the clearing price set under the VOLL-based demand curves will be excessive and will send a price signal for entry that is too strong, resulting in inefficient and therefore unjust and unreasonable rates, according to the Midwest TDUs. They also

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[92] *See* February 25 Order, 122 FERC ¶ 61,172 at P 151-55.

[93] *See* Midwest ISO, FERC Electric Tariff, Fourth Revised Sheet No. 716 § 53.1A ("Auditing for Physical Withholding").

[94] *See Midwest Indep. Transmission Sys. Operator*, 123 FERC ¶ 61,296, at P 65 (2008).

[95] *Wholesale Competition in Regions with Organized Electric Markets*, Notice of Proposed Rulemaking, 73 Fed. Reg. 12,576 (Mar. 7, 2008), FERC Stats. & Regs. ¶ 32,628 (2008).

[96] *See* February 25 Order, 122 FERC ¶ 61,172 at P 213.

assert that the Midwest ISO market design results in over-recovery of entry costs, providing investors with more than a normal return on investment. For these reasons, the Midwest TDUs argue that the VOLL should be reduced to reflect these other sources of resource adequacy.

103. The Midwest TDUs also ask if the costs associated with a DRR-I would be recovered in an emergency if the costs exceed the $1000/MWh cap. The Midwest TDUs aver that while the high costs associated with the deployment of DRR-I resources should not set the LMP, the Midwest ISO should not be able to call upon these resources without compensating the provider for its verified costs. The Midwest TDUs further contend that, by extending the $1000/MWh cap to DRR-I resources, without addressing the integration of the Midwest ISO emergency demand response (EDR) proposal in Docket No. ER08-404 with the ASM, the Commission may limit the Midwest ISO's flexibility to maintain reliability in a severe emergency or deprive entities with high cost DRR-I resources from recovering verified costs when deployed in an emergency.

104. Midwest Transmission Customers fault the Commission for approving the scarcity pricing proposal without evidence that demand response resources can effectively participate in the Midwest ISO markets to mitigate potential market power and discipline prices. Midwest Transmission Customers contend that the Competition NOPR recognizes that the introduction of scarcity pricing carries with it concerns over the exercise of market power and the Commission made similar findings in the Guidance Order. The IMM's proposal to report on misconduct,[97] rather than undertaking an assessment of demand responsiveness and demand elasticity before potentially high prices, does not address the concern about the appropriate scarcity pricing at this time, according to Midwest Transmission Customers.

### 3. <u>Commission Determination</u>

105. While some resources may receive fixed-cost compensation in either retail rates or long-term wholesale contracts, some resources may not receive those payments and those resources may be the resources needed to provide reserves in emergencies. The Commission cannot assume that resource payments are sufficient for the efficient and reliable management of emergencies and therefore that the scarcity pricing cap can be eliminated or reduced. Instead, the Commission must ensure that the market design provides the appropriate price signals to ensure all resources have an incentive to participate in emergencies, and thereby maintain short-term reliability without resorting to load shedding any sooner than necessary. Reducing scarcity prices means fewer

[97] The IMM stated he will provide an on-going assessment of the expected response of generation and demand resources to the proposed scarcity demand curves. Patton Aff. at 11.

resources will provide energy in emergencies and therefore represents a reliability risk this Commission does not consider prudent. We consider the $3,500/MW cap on scarcity prices reasonable when considered in the Midwest ISO emergency planning context, as the last step after all other physical management steps have been taken, and in the context of the mitigation measures that will ensure the market is not manipulated and market power is not exercised.[98] Accordingly, we deny the Midwest TDUs' request for rehearing of the Commission's acceptance of the Midwest ISO scarcity pricing provisions.

106. The EDR proposal in Docket No. ER08-404[99] only applies to scarcity conditions in which resources cannot make offers and therefore the $1000/MWh offer cap is not applicable, and prices for all resources – EDRs and DRRs – are set by a demand curve that is capped at $3500/MWh. We deny rehearing of the Commission's determination in the February 25 Order that the $3500/MWh cap is reasonable since it represents the reliability value of capacity based on the VOLL analysis. We consider this scarcity price level, the highest of any RTO or ISO, to be a significant incentive for participation by all resources, including demand resources, and therefore we consider this price level appropriate for ensuring reliability in emergency conditions after all physical measures have been exhausted.

107. We expect the Midwest ISO demand response programs providing demand resources during emergency conditions – both emergency demand resources (EDRs) and DRRs in the ASM – will encourage demand response participation during scarcity conditions since the Midwest ISO designed these programs with many of the features used successfully by other RTOs and ISOs in their demand response programs. While demand response can play a role in disciplining prices, we consider its role to be one of many market features that ensure the scarcity pricing provisions are just and reasonable and therefore we are not looking to demand response to be the sole or primary program to discipline prices or mitigate the exercise of market power. Rather, as discussed above, acceptance of the Midwest ISO scarcity pricing proposal has been predicated on a number of mitigation, market entry and physical management provisions, all of which ensure scarcity pricing will only be invoked during true scarcity situations. We agree with the IMM that the best time to evaluate the reasonableness of the Midwest ISO scarcity demand curves is when actual emergencies occur and actual market behavior can be analyzed. We do not consider it reasonable to bar the implementation of scarcity

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[98] The integration of demand resources into the ASM will also reduce the likelihood that scarcity pricing will have to be invoked.

[99] The Commission conditionally accepted the Midwest ISO EDR proposal on April 22, 2008. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 123 FERC ¶ 61,070 at P 25-26.

demand curves while various demand elasticity studies are undertaken since such studies are not a substitute for actual market experience. For these reasons, we deny the request for rehearing of Midwest Transmission Customers.

### G. Self-Scheduling and Self-Supply

#### 1. February 25 Order

108. The Commission found the self-schedule option in the Midwest ISO proposal to be just and reasonable. The Commission noted the proposal allows market participants to make bilateral contracts and there is no requirement for the payment of congestion and losses, and therefore the option provides all the features of self-supply.[100]

#### 2. Requests for Rehearing

109. The Michigan Power Agencies assert the Commission departed from Order No. 888 in its acceptance of the Midwest ISO proposal, arguing that Order No. 888 specifically references a requirement for self-supply. They contend that the Commission's reliance on the Midwest ISO statements regarding the benefit of eliminating the self-supply option does not represent a reasonable basis for approving the proposal.

110. The Michigan Power Agencies argue that self-scheduling is not interchangeable with self-supply because self-scheduling subjects resources to the Midwest ISO dispatch control, whereas self-supply would not have this requirement. The Michigan Power Agencies maintain that the Michigan Power Agencies' Power Pool is not currently under the Midwest ISO dispatch and that the self-schedule option would put the resources of the pool under Midwest ISO control and thereby violate the core provision of the agreements governing the pool, effectively abrogating these contracts. The Michigan Power Agencies also assert that the self-supply option will increase their costs to install additional control and communications equipment, or, in the alternative, require the purchase of ancillary services from the Midwest ISO ASM at a higher cost than the cost of self-supply.

#### 3. Commission Determination

111. We deny rehearing of the Commission determination that the Midwest ISO self-scheduling option is just and reasonable. The Commission based its determination on the Midwest ISO's explanation that the self-scheduling option allows market participants to make bilateral contracts and there is no requirement for the payment of congestion and

[100] *See* February 25 Order, 122 FERC ¶ 61,172 at P 324-25.

losses, and therefore the option provides all the features of self-supply.[101] We do not consider it unreasonable that self-schedules may be revised as necessary by the Midwest ISO, acting as the Balancing Authority, to ensure compliance with applicable Electric Reliability Organization (ERO) standards.[102] The Midwest ISO, just like all other RTOs and ISOs, must manage reliability. Moreover, the Michigan Power Agencies, as a market participant in the Midwest ISO, are bound to follow Midwest ISO reliability instructions. We note that since the start of the Midwest ISO energy markets, the Midwest ISO has had the ability to issue dispatch instructions to manage reliability.[103] Therefore, we do not consider the Midwest ISO proposal to adjust the provision of self-supply in order to manage reliability to represent a change in these operating procedures or to represent a change in the operating limitations on self-supply.

112. We recognize that the Midwest ISO will be managing a centralized ASM and this may require market participants to install additional communication equipment. However, we do not find a basis to conclude that the installation of communication equipment will foreclose self-supply, or that the Michigan Power Agencies will be forced to pay for higher cost reserves. Similarly, we find nothing in the ASM provisions that forces market participants to sell their output to the market rather than to themselves. Accordingly, we do not find the ASM provisions to be detrimental to the self-supply option, and we deny the rehearing request.

## H. Demand Response Resources

### 1. Settlement of Demand Response Resources

#### a. February 25 Order

113. The Commission found the Midwest ISO settlement method,[104] that determines how DRRs-I will be compensated, to be reasonable. The Commission noted that the method proposed by the Midwest ISO is used to settle DRRs in several other RTOs and

[101] *Id.* P 323.

[102] *Id.*

[103] We disagree with the Michigan Power Agencies' contention that its generation resources are not subject to Midwest ISO dispatch.

[104] This settlement method, the gross load settlement method, refers to the practice of either not charging load for energy not consumed or paying the DRR for energy that was not consumed.

ISOs and there has been no indication that the operation of that settlement method has resulted in unreasonable outcomes.[105]

### b. Requests for Rehearing

114. Midwest Transmission Customers contend that it would be economically irrational for customers that choose to enter into bilateral contracts to abandon the price certainty provided by such contracts and subject themselves to the Midwest ISO settlement method since this method attributes zero value to a customer's call option,[106] even if the market is experiencing scarcity conditions. Midwest Transmission Customers also argue that the Commission's determination is inconsistent with approaches used by other RTOs and ISOs and fails to give proper weight to actual experience in other RTOs and ISOs, and the role of demand response in disciplining prices. Alcoa claims that the gross load settlement method does not account for the fact that behind-the-meter generation is being made available to serve load through the reduction in demand and therefore makes these demand reductions equivalent to adding generation. Alcoa states that there is no basis for discriminating between a demand reduction that is facilitated by behind-the-meter generation and generation, which it claims is what the gross load settlement does. For these reasons, Alcoa asserts that the Commission erred by not allowing settlement to be based on the net impact on the system only.

115. Midwest Transmission Customers argue that the February 25 Order does not address the following issues: (1) its concerns that there is confusion with regard to the settlement of behind-the-meter generation resources that elect to participate as DRR-II resources; (2) Alcoa's request for clarification with respect to the load curtailment capability to purchase energy as a DRR-II; and (3) the Midwest ISO answer in the root docket of this proceeding, ER07-1372-000, clarifying this issue.[107] Accordingly, Midwest Transmission Customers request that the Commission grant rehearing and direct the Midwest ISO to clarify the relevant sections of its tariff.

### c. Commission Determination

116. We deny rehearing with respect to the Commission's finding in the February 25 Order that the gross load settlement method is reasonable. The gross load method

[105] *See* February 25 Order, 122 FERC ¶ 61,172 at P 340.

[106] Midwest Transmission Customers explain that since a bilateral contract provides for a fixed price, it is equivalent to a call option for energy at a predetermined strike price.

[107] *See* Midwest ISO November 6, 2007 Answer at 58-64 (Midwest ISO Answer).

compensates DRRs for the energy they provide and therefore provides an incentive for demand response resources to participate. Considering the high price caps in effect during scarcity conditions, we consider compensation at these levels to be a significant incentive, and therefore we disagree with the contention of Midwest Transmission Customers that DRRs have little incentive to participate during scarcity conditions. Nor do we consider it irrational for customers to participate as DRRs instead of taking utility service at fixed rates or entering into bilateral contracts. These customers will be compensated for their DRRs under the gross load method, and therefore stand to gain economically from their participation. Nor do we consider the gross load settlement method inconsistent with the approaches taken by other RTOs and ISOs. As indicated in the Midwest ISO's answer,[108] other RTOs and ISOs use both the gross load and net load settlement methods.[109]

117. With respect to the related issue of net and gross load accounting raised by Alcoa and Midwest Transmission Customers, the Midwest ISO proposal allows market participants to net their behind-the-meter generation against their gross load so that they will receive a payment for demand response resource participation even when their net load is zero, i.e., the behind-the meter generation provides reserves equal to load.[110] This method accurately reflects the reserves provided by demand response resources. To the extent the Midwest ISO software does not allow the result portrayed in its answer, as alleged by Alcoa, we require the Midwest ISO to adjust its software systems accordingly. We require the Midwest ISO to submit a status report on this issue in an informational filing to be submitted within 30 days of the date of this order. We find no basis to conclude that the gross load settlement method discriminates against behind-the-meter generation. As detailed above, behind-the-meter generation is paid for the energy provided and therefore is treated comparably to other resources.

### 2. Other Demand Response Resource Issues

#### a. February 25 Order

118. The Commission determined that the Midwest ISO proposal requiring the submittal of five-minute dispatch interval forecasts to be reasonable since this method provides for an up-to-date and accurate basis for performance monitoring. Similarly, the Commission accepted the one-minute interval basis for the metering of consumption of a DRR that has been committed for energy or is available to be cleared for contingency

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[108] *See id.* at 60.

[109] *See* February 25 Order, 122 FERC ¶ 61,172 at P 337.

[110] *See* Midwest ISO Answer at 58.

reserves, noting that such a measure is needed for the efficient and reliable management of the ASM. However, the Commission required the Midwest ISO to explain the purpose of its provision limiting the five-minute forecasts to one-twelfth of the highest demand. With respect to batch-load resources, the Commission found the five-minute forecast process would be able to recognize changes in batch loads, and thereby avoid assessing contingency deployment penalty charges, and therefore would remove barriers to participation of demand resources.[111]

### b. Requests for Rehearing

119. Alcoa argues that the five-minute interval for forecasts is unnecessary for operation of the power system, and that an hourly forecast could be used for the same purposes since settlements are based on hourly intervals. Alcoa further argues that a five-minute forecast is more onerous to predict than a one-hour load forecast because the prospect of intra-hour variations and the five-minute forecast does not determine the ability of the resource to respond. Steel Producers also consider the five-minute dispatch interval to be unreasonably burdensome. Alcoa, objecting to Commission acceptance of the one-minute interval requirement for metering, claims that it is not necessary that the Midwest ISO instantaneously verify whether resources have properly responded. Alcoa contends that an hourly forecast with hourly metering is sufficient to give the Midwest ISO a reasonably accurate outlook on all projected load and an opportunity to direct a response.

120. Midwest Transmission Customers take exception to the Commission's directive that the Midwest ISO explain the purpose of the one-twelfth limit on five-minute dispatch interval forecasts, and argues that the Midwest ISO should be required to remove this provision. Alcoa also argues for removal of this provision.

121. Alcoa expresses concern that the Commission may not have fully comprehended the active utilization of forecasting tools required to accommodate the Midwest ISO-proposed batch-load program, noting that this program does not recognize the value of a response to a given set point within the system, as opposed to a specific MW response. Midwest Transmission Customers argue that the dispatch interval demand forecasts required for batch-type resources are speculative and contend that predictions do not lend themselves to metering for performance measurement and verification. Similarly, Steel Producers argue that the forecast provision introduces an unnecessary element of chance and unreliability into the process and that the Midwest ISO proposal therefore constitutes an unnecessary barrier to demand response participation in violation of EPAct 2005.[112]

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[111] February 25 Order, 122 FERC ¶ 61,172 at P 351.

[112] Steel Producers Comments at 4; Energy Policy Act of 2005, 119 Stat. at 594.

122. Alcoa faults the Commission for accepting the Midwest ISO proposal to combine spinning and supplemental reserves into a single product category, explaining that Alcoa can provide spinning reserves but cannot supply supplemental reserves because of the operational characteristics of its manufacturing process.

### c. **Commission Determination**

123. With respect to the dispatch interval forecast requirement, we deny rehearing with respect to the Commission's determination that the dispatch interval forecast requirement is reasonable. Since the start of its energy markets, the Midwest ISO has required resources to provide five minute forecasts so that the state estimator can accurately track system conditions as close to real-time as possible. The Midwest ISO requirement for DRRs, therefore, is a continuation of its current reliability management of system conditions. To the extent DRRs are providing reserves, they must assist the Midwest ISO in managing reliability and therefore they should be held to the same forecasting requirements applicable to other resources providing reserves. Likewise, the one-minute interval requirement for submittal of metered consumption is a performance standard that resources have been required to meet since the start of the energy markets and the Midwest ISO indicated in its answer that this requirement is needed to verify resource performance in real-time.[113] DRRs must assist the Midwest ISO in managing reliability, and performance verification is a reasonable requirement for managing reliability.[114] Considering that the Midwest ISO indicates that it needs this measure to manage reliability in real-time, we have no basis to conclude, as Alcoa does, that the Midwest ISO does not need these measures to manage reliability.

124. We note that the Midwest ISO is proposing, in its compliance filing, to delete its provisions that limit the five minute forecasts to one-twelfth of the highest demand. Accordingly, we find the rehearing requests of Alcoa and Midwest Transmission Customers are moot, and instead address the revised provisions in the compliance order being issued concurrently with this order.

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[113] *See* Midwest ISO Answer at 59.

[114] We do not consider a testing and data exchange process, as suggested by Alcoa, to be a viable substitute for offer commitments and real-time data and forecasts by market participants. The best information for determining the availability of reserves is provided by the offers of market participant and their real-time data and forecasts. In contrast, testing and data exchanges can only approximate the potential availability of demand response resources and therefore do not provide a real-time basis for determining the status of resources.

125. We also deny rehearing of the Commission's determination regarding batch-load demand response. The Midwest ISO dispatch interval forecast requires market participants to provide a forecast of their load and the amount of load they would be willing to reduce in order to provide reserves. Considering that the manufacturer is in control of its manufacturing process and has extensive knowledge of the operating characteristics of its facilities, we do not consider such a forecast speculative or difficult to determine. While Alcoa and Midwest Transmission Customers assert that demand resources can provide a set-point benefit and a benefit for consuming energy below a firm contract quantity, we do not have any information to conclude that these potential or hypothetical benefits result in an actual and measurable reduction in load – and thereby provide actual reserve MWs to the Midwest ISO system – and therefore we cannot find a basis for compensating demand response resources or avoiding the contingency reserve penalty for these benefits. However, we require the Midwest ISO to evaluate the recommendations of Alcoa and Midwest Transmission Customers and discuss the issue with stakeholders.

126. Responding to the Steel Producers, we consider the five-minute forecast interval for batch load demand response to be reasonable and deny its rehearing request. We do not expect that market participants in control of their manufacturing process and with extensive knowledge of the operational characteristics of their facilities will have difficulty forecasting in five-minute intervals, with updates allowed every five minutes, and we expect that such granularity will minimize forecast error. Given the magnitude of the response of the facilities discussed by Steel Producers, i.e., 50 MW- 125 MW, we consider a forecasting requirement reasonable and encourage the Midwest ISO to discuss with stakeholders ways to minimize the costs of forecasting. Because we have determined that the Midwest ISO method is reasonable, we find no reason to consider the adoption of a method used by PJM.

127. Market participants can provide either spinning reserves (Schedule 5) or supplemental reserves (Schedule 6) and there is no conditional requirement that market participants must offer both types of reserves. The Commission's determination cited by Alcoa applies only to the definition of the reserves market used by the IMM in his market power study.[115]

[115] We note the Midwest ISO in its 60-day compliance filing submitted on April 25, 2008 is addressing the concern of Alcoa that it cannot participate in the supplemental reserve market with a new proposal to facilitate the participation of demand resources in this market.

### I. Pseudo-Ties

#### 1. February 25 Order

128. The Midwest ISO proposal requires qualified reserve resources to be either physically located within the Midwest ISO Balancing Authority Area or the entire generation resource must be pseudo-tied into the Midwest ISO Balancing Authority Area or the resource must be an external asynchronous resource.[116]

#### 2. Requests for Rehearing

129. Midwest TDUs argue that the Commission did not address their protest that external resources that are synchronized with the Midwest ISO should be allowed to participate on the same basis as Western Interconnection resources.[117] Midwest TDUs object to the fact that external resources that are synchronized with the Midwest ISO must be pseudo-tied, whereas external resources that are not synchronized – since they are either outside the Eastern Interconnection or broken out from the Eastern Interconnection as an asynchronous island connected through DC ties – are eligible to be reserve resources if they are capable of receiving and responding to dispatch target and setpoint instructions from the Midwest ISO.

130. Midwest TDUs assert that there is no reason why replacing a DC tie with a synchronized AC connection would require the installation of a pseudo-tie. Midwest TDUs also claim that requiring a pseudo-tie can impose a significant burden and market friction since the pseudo-tie registration occurs quarterly and efficient use for the operating reserve capability of a resource may change intra-quarterly. According to Midwest TDUs, absent a reliability-based reason for a pseudo-tie, the Midwest ISO should give synchronous external resources the same flexible rights that it gives asynchronous external resources.

#### 3. Commission Determination

131. As a preliminary matter, we note that external asynchronous resources connected via DC ties are represented through a dynamic interchange schedule as an import schedule in the energy and reserve markets. As a schedule from a DC tie, there is only a single location of the energy from the DC tie connection. In contrast, external resources connected via AC connections through pseudo-ties can change the location of the resource and the amounts provided by various resources. Under these circumstances, the

[116] *See* February 25 Order, 122 FERC ¶ 61,172 at P 366.

[117] *See id.* P 373.

Midwest ISO needs to know the location of the source and the volumes being imported from various resources and therefore needs telemetering equipment to monitor these variables. We interpret Midwest TDUs' concern to be that they do not want their external synchronized resources pseudo-tied because they do not want to install the necessary telemetering equipment and they want the flexibility to offer their external resources into the ASM without waiting for the quarterly registration process. We reject arguments that the Midwest ISO pseudo-tie requirement is not reasonable. The pseudo-tie requirement ensures that the Midwest ISO knows the real-time status of external resources and this requirement is important to the management of a an efficient and reliable centralized ASM. Without the pseudo-tie, the Midwest ISO must estimate by other, less precise, means the status of external resources providing reserves and this loss of precision hinders the efficiency and reliability of the ASM.

132. We understand the quarterly registration process to be a function of the quarterly network model update. While we do not find a quarterly update process unreasonable, we encourage the Midwest ISO to work with stakeholders on a more flexible registration process to facilitate the maximum participation of resources in the ASM.

### J. Stakeholder Process

133. In the February 25 Order, the Commission considered the ongoing stakeholder task forces and continuing reviews of the ASM to be responsive to the concerns of market participants and the best approach for ensuring that remaining stakeholder issues are addressed.[118]

134. Alcoa asserts that the Midwest ISO stakeholder process is broken. Alcoa cites to the domination of task forces by traditional generating utilities and transmission service providers as the cause for lack of innovation or accommodation with respect to unique load profiles and new technologies. Alcoa claims that there is no reasonable basis to conclude that the Midwest ISO stakeholder process will produce just and reasonable outcomes.

135. We do not consider the Midwest ISO stakeholder process "broken" because the stakeholder committees reflect the traditional generating utilities and transmission service providers that make up the largest share of market participants. The Commission's finding that the stakeholder process was reasonable was based on the several-year stakeholder review process during which the ASM proposal was explained to all stakeholders and developed with their assistance. We do not consider it reasonable to require that the position of the stakeholder committees on important issues fully reflect the position of each market participant and therefore, similar to other unique market

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[118] *See id.* P 28.

participants with special circumstances, such as Manitoba Hydro and Detroit Edison, we encourage Alcoa to raise its concerns before this Commission to ensure its interests are understood and incorporated into the design of the Midwest ISO markets.

## K. Revenue Sufficiency Guarantee Charge

136. The Commission determined the issue of the definition of market participants liable for RSG charges to be beyond the scope of this proceeding and noted that the allocation of RSG costs is being evaluated by the Commission in other proceedings in Docket Nos. ER04-691, EL07-88, EL07-92 and EL07-96.[119]

137. Hoosier & Southern Illinois disagree with the Commission's determination, asserting that the Commission has never before accepted a tariff provision providing for the allocation of uplift costs resulting from the implementation of the ASM to only those market participants that withdraw energy. Therefore, they assert, it is incumbent on the Midwest ISO to demonstrate that its proposal was just and reasonable. Hoosier & Southern Illinois further note that the Midwest ISO has not made such a demonstration.

138. The RSG charge applicable to the ASM is the same charge applicable to the energy market, and this provision has been accepted by the Commission and in effect since the start of the energy markets. Therefore, we disagree with Hoosier & Southern Illinois that the RSG charge is a new provision being evaluated for the first time in this proceeding. We also do not consider a demonstration of the justness and reasonableness of the provision to be necessary. That determination was made in the Commission order accepting the provision at the start of the energy markets. The currently effective provision assesses RSG charges to market participants withdrawing energy, and therefore the continued applicability of the charge to these market participants is appropriate. The appropriate venue to challenge the currently-effective provision is in the complaint proceedings in Docket Nos. EL07-86, EL07-88 and EL07-92.

## L. Cost and Benefits of the Proposed ASM

139. The Commission determined in the February 25 Order that the task force set up by the Midwest ISO to work with stakeholders and state commission representatives to perform an ongoing analysis of costs is the appropriate venue for evaluating the costs and benefits of the ASM. The Commission noted that the task force provides stakeholders with the most relevant information available and provides a forum to allow stakeholders

[119] *See id.* P 554.

to raise their concerns. The Commission also stated that it is not required to condition its approval of the ASM proposal on Commission approval of cost-benefit studies.[120]

140. Hoosier & Southern Illinois argue that there is no basis for concluding that the design features of other ISOs have worked successfully or that reliability and efficiency benefits will be realized in the Midwest ISO ASM. Hoosier & Southern Illinois also assert that the Commission should not approve the ASM proposal if the Midwest ISO cannot demonstrate that the benefits will outweigh the costs, noting that the Federal Power Act affords consumers a complete and effective bond of protection from excessive rates and charges.

141. We deny rehearing of the Commission's finding that the best method for customers to ensure that the costs of the ASM are reasonable is the ongoing cost and benefit analysis being undertaken by the Midwest ISO for the stakeholder and state commission task force. Such a process provides the information relevant to the concerns of Hoosier & Southern Illinois with respect to excessive charges and also provides a forum for Hoosier & Southern Illinois to raise their concerns. Until the ASM begins operation, the Commission has no basis to conclude that the ASM charges are unjust and unreasonable. The Commission's statements in the February 25 Order on the operation of the Midwest ISO's ASM therefore represent its reasonable expectations. We find that it is reasonable to base those expectations on the performance of other ISOs with similar ASMs.

<u>The Commission orders</u>:

(A) The requests for rehearing are hereby granted in part and denied in part.

(B) The Midwest ISO is hereby directed to make a compliance filing, within 30 days of the date of this order, as discussed in the body of this order.

By the Commission. Commissioner Wellinghoff dissenting with a separate statement attached.

( S E A L )

Kimberly D. Bose,
Secretary.

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[120] *See id.* P 25-26.

**Appendix A**

**Parties who submitted rehearing requests:**

- Dynegy Power Marketing, Inc. (Dynegy)
- Organization of Midwest ISO States (OMS)
- Duke Energy Corporation (Duke)
- Ameren Services Company (Ameren)
- Michigan Public Power Agency (Michigan Public Power)
- Alcoa Inc. and Alcoa Power Generating, Inc. (Alcoa)
- Steel Producers
- Hoosier Energy Rural Electric Cooperative, Inc. & Southern Illinois Power Cooperative (Hoosier & Southern Illinois)
- Coalition of Midwest Transmission Customers (Midwest Transmission Customers)
- Midwest Transmission Dependent Utilities (Midwest TDUs)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Midwest Independent Transmission System Operator, Inc. Docket No. ER07-1372-003

(Issued June 23, 2008)

WELLINGHOFF, Commissioner, dissenting:

I dissented from the February 25 Order approving Midwest ISO's ancillary services market (ASM).[1] I expressed my concern that the ASM, as constructed, erects unnecessary barriers to the participation of demand response. As I described in detail, the obstacles faced by demand response providers include, among others, an expensive and unnecessary telemetering requirement, an overly restrictive 60-minute sustainability requirement, and inadequate compensation.

On rehearing, several parties further explain how the ASM's requirements will discourage, and may preclude, demand response providers from participating in the ASM. Parties raising such concerns include the Coalition of Midwest Transmission Customers, the Illinois Industrial Energy Customers, and the Midwest Industrial Customers (collectively, Midwest Transmission Customers); Alcoa Inc and Alcoa Power Generating Inc. (collectively, Alcoa); and Nucor Steel Marion Inc., Nucor Steel-Indiana, and SDI-Pittsboro (collectively, Steel Producers). Despite these parties' reasonable concerns, the majority fails to make any changes to Midwest ISO's proposals. Therefore, consistent with my previous statement in this proceeding, I respectfully dissent.

I also write separately to note that in EPAct 2005, the Congress stated that it is the policy of the United States to eliminate unnecessary barriers to demand response participation in the energy, capacity, and ancillary service markets.[2] The Congress further stated that it is the policy of the United States that demand response shall be encouraged, and that the deployment of demand response technology shall be facilitated.

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[1] *Midwest Independent Transmission System Operator, Inc.*, 122 FERC ¶ 61,172 (2008).

[2] EPAct 2005 §1252(f), 119 Stat. 966 (2005).

Unfortunately, the majority's actions in this proceeding fall far short of these goals.[3] We must do more to encourage and facilitate the participation of demand response in markets like the ASM, and to eliminate unnecessary barriers to that participation.

Jon Wellinghoff
Commissioner

[3] *Id.*