153 FERC ¶ 61,229
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, and Tony Clark.

Midwest Independent Transmission System Operator, Inc. — Docket No. ER11-4081-001

ORDER ON REHEARING

(Issued November 20, 2015)

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1. On June 11, 2012, the Commission conditionally accepted proposed revisions by Midwest Independent Transmission System Operator, Inc. (MISO) to its Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff).[1] The revisions were intended to comply, in part, with the Commission's order addressing concerns about the deliverability of capacity resources throughout the MISO region.[2] Several parties seek rehearing and clarification of the June 11 Order. As discussed further below, we deny rehearing and, in part, grant clarification.

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[1] *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 FERC ¶ 61,199 (2012) (June 11 Order). Effective April 26, 2013, MISO changed its name from "Midwest Independent Transmission System Operator, Inc." to "Midcontinent Independent System Operator, Inc."

[2] *Midwest Indep. Transmission Sys. Operator, Inc.*, 126 FERC ¶ 61,144 (2009) (Locational Requirements Order), *order rejecting compliance filing*, 131 FERC ¶ 61,228 (2010) (Locational Requirements Compliance Order), *order on clarification*, 135 FERC ¶ 61,081 (2011).

I. <u>Background</u>

2. The Commission conditionally approved MISO's previous resource adequacy construct in March 2008.[3] In the March 2008 Order, the Commission generally accepted MISO's plan to create a mandatory Planning Reserve Margin for each Load Serving Entity (LSE) and to require each LSE to bilaterally procure capacity to satisfy its Planning Reserve Margin.[4] In the March 2008 Order, the Commission required MISO to propose financial settlement provisions for the resource adequacy construct, which would assess a Financial Settlement Charge on LSEs that are deficient in meeting their resource adequacy requirements.[5] Observing the importance of resource deliverability, the Commission also required MISO to "clarify the method it [would] use to 'establish additional planning zones . . . to address regional issues,'" such as transmission constraints, and to include the details of its zonal methodology in the Tariff.[6]

3. MISO submitted a compliance filing with proposed financial settlement provisions in June 2008. At that time, MISO proposed to assess Financial Settlement Charges against LSEs that failed to satisfy the resource adequacy requirement.[7] In addition, MISO proposed to establish the current voluntary capacity auction "to allow LSEs with insufficient capacity to satisfy their resource adequacy requirements with planning resources from market participants that have excess planning resources."[8] In support of the voluntary construct, MISO argued that its proposal represented "a reasonable compromise position between those stakeholders that opposed any type of capacity auctions and those that advocated mandatory capacity auctions."[9] In the Financial

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[3] *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,283 (March 2008 Order), *reh'g denied*, 125 FERC ¶ 61,061 (2008).

[4] March 2008 Order, 122 FERC ¶ 61,283 at PP 360, 365, and 376.

[5] *Id.* P 179.

[6] *Id.* P 169.

[7] *Midwest Indep. Transmission Sys. Operator, Inc.*, 125 FERC ¶ 61,060, at P 9 (2008) (Financial Settlement Order), *order on reh'g and compliance*, 127 FERC ¶ 61,054 (2009) (Financial Settlement Rehearing Order), *order on reh'g and compliance,* 137 FERC ¶ 61,213 (2011) (Financial Settlement Second Rehearing Order).

[8] Financial Settlement Order, 125 FERC ¶ 61,060 at P 8.

[9] *Id.* P 32.

Settlement Order, the Commission accepted the voluntary construct because "[t]he voluntary auction will afford LSEs with an additional mechanism to procure needed capacity and increase transparency in the procurement of capacity."[10] The Commission further emphasized that its acceptance was based "solely on the reasonableness of the auction mechanism in providing a useful alternative option for obtaining capacity in the [MISO]."[11] The Commission further explained that it did not consider the voluntary auction as a precursor to a mandatory capacity auction.[12] The Commission also rejected arguments that a mandatory auction or a mandatory centralized capacity market is necessary to ensure resource adequacy.[13]

4. With respect to the development of additional planning zones as required by the March 2008 Order, the Commission conditionally accepted MISO's May 2008 compliance filing.[14] However, the Commission remained concerned with resource deliverability, as it has throughout the development of MISO's resource adequacy construct. The Commission observed that, "[a]ny congestion limits the ability of the system operator to import additional resources and those limitations must be reflected in the creation of additional zones."[15] Specifically, the Commission shared deliverability concerns raised by numerous stakeholders about a possible "disconnect between the deliverability analysis used in the creation of planning zones and the analysis used to evaluate designated capacity resources."[16] As a result, the 2008 Compliance Order required MISO to further "clarify . . . and/or align the deliverability requirements of planning reserve zones and capacity resources."[17]

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[10] *Id.* PP 36-38.

[11] *Id.* P 38.

[12] *Id.*

[13] *Id.* P 39. The Commission also declined to require MISO to "adopt a downward-sloping demand curve in the mold of PJM and the New York ISO." *Id.*

[14] *Midwest Indep. Transmission Sys. Operator, Inc.*, 125 FERC ¶ 61,062, at P 160 (2008) (2008 Compliance Order).

[15] *Id.*

[16] *Id.* P 162.

[17] *Id.*

5. The Commission once again expressed its concern that transmission constraints would limit aggregate deliverability in the Locational Requirements Order, which addressed rehearing of and compliance with the 2008 Compliance Order.[18] Despite conditionally accepting MISO's proposed clarification in response to the 2008 Compliance Order, the Commission explained "that a more robust and permanent approach to addressing congestion that limits aggregate deliverability is ultimately required."[19] In order to resolve these deliverability concerns, the Commission directed MISO to evaluate locational capacity requirements in other regions to ensure sufficient capacity is available in import-restricted zones to satisfy the Planning Reserve Margin. Further, the Locational Requirements Order directed MISO to "inform the Commission . . . what steps are being taken to develop a more permanent approach."[20] The Commission subsequently rejected MISO's filing submitted in compliance with the Locational Requirements Order because MISO had failed to address aggregate deliverability in the region.[21] Thus, the Commission clarified that the Locational Requirements Order requires MISO to "develop a plan that details the steps that will be taken to incorporate [locational] market mechanisms into the Resource Adequacy Plan."[22]

II. <u>June 11 Order</u>

6. In July 2011, MISO filed revisions to its resource adequacy construct. In the June 11 Order, the Commission accepted most of the features of MISO's resource adequacy proposal, including its proposal to allow LSEs to meet their planning resource requirements by: (1) participating in the Planning Resource Auction (auction); (2) self-scheduling resources into the auction; or (3) opting out of the auction by submitting a fixed resource adequacy plan. The Commission also accepted the major elements of MISO's resource adequacy construct for an annual Planning Year with a two-month forward period and a vertical demand curve. However, the Commission rejected MISO's proposed mandatory auction requirement because MISO had not met its burden that the proposal was just and reasonable because it had not demonstrated that a mandatory construct was necessary. The Commission also rejected MISO's Minimum Offer Price

[18] Locational Requirements Order, 126 FERC ¶ 61,144 at P 47.

[19] *Id.*

[20] *Id.*

[21] Locational Requirements Compliance Order, 131 FERC ¶ 61,228 at P 23.

[22] *Id.* P 24.

Rule (MOPR) proposal due to the lack of incentives for price suppression in MISO's market and the ineffectiveness of MISO's proposal.

7. In addition, the Commission accepted MISO's locational market mechanism that would provide for auctions in Local Resource Zones and the assessment of Zonal Deliverability Charges to reflect the impact of deliverability constraints between resources and loads. The Commission rejected MISO's proposal to exempt certain LSEs from Zonal Deliverability Charges to the extent these LSEs possess firm transmission service from their resources to their load since such an exemption would mute the locational price signal. However, in recognition of the fact that LSEs that have historically relied on remote generation may need a period of time to adjust resource portfolios and plan for additional resources, the Commission allowed these exemptions, called Grandmother Agreements, to be in effect during a transition period that phases out at the end of the 2014/2015 Planning Year. Finally, the Commission accepted the other elements of MISO's proposal with the exception of its proposal for load forecasting in retail choice regions.

III. Requests for Rehearing and Other Pleadings

8. Requests for rehearing were filed by MISO's Independent Market Monitor (Market Monitor); Wisconsin Public Service Corporation and Upper Peninsula Power Company (Wisconsin PSC); Capacity Suppliers;[23] NRG Companies (NRG);[24] Great River Energy; Midwest TDUs;[25] American Public Power Association (APPA); Demand Response Supporters;[26] and Dairyland Power Cooperative, Hoosier Energy Rural Electric

[23] Capacity Suppliers are Ameren Energy Marketing; Calpine Corporation; Dynegy Power Marketing, LLC; Dynegy Midwest Generation, LLC; Electric Power Supply Association; Exelon Corp. (Exelon); FirstEnergy Solutions Corp. and NextEra Energy Resources, LLC (NextEra).

[24] NRG Companies are Louisiana Generating LLC; Bayou Cove Peaking Power LLC; Big Cajun I Peaking Power LLC; Cottonwood Energy Company LP; NRG Sterlington Power LLC; and NRG Power Marketing, LLC.

[25] For purposes of this request for rehearing, Midwest TDUs consist of Indiana Municipal Power Agency, Madison Gas & Electric Company, Midwest Municipal Transmission Group, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, and WPPI Energy.

[26] Demand Response Supporters are Comverge, Inc.; EnergyConnect by Johnson Controls; EnerNoc, Inc.; and Energy Curtailment Specialists, Inc.

Cooperative, Inc. (Hoosier) and Southern Illinois Power Cooperative (Southern Illinois) (together, Dairyland). Ameren Services Company (Ameren) filed a request for rehearing and clarification. Wisconsin Electric Power Company (Wisconsin Electric), Illinois Municipal Electric Agency (Illinois Municipal), and the Coalition of MISO Transmission Customers (Coalition of MISO Customers) filed requests for clarification and alternate requests for rehearing. Michigan Citizens Against Rate Excess (Michigan Citizens) filed a request for rehearing or, in the alternative, request to file additional comments out-of-time. Louisiana Energy and Power Authority and Conway Corporation filed motions to intervene out-of-time and comments requesting that the Commission deny rehearing.

9. On July 26, 2012, Hoosier and Southern Illinois filed a motion for leave to answer and answer to Capacity Suppliers' and NRG's requests for rehearing. Also on July 26, 2012, Hoosier and Southern Illinois filed a motion to reject the Market Monitor's request for rehearing.

10. Motions to intervene out-of-time were filed by Arkansas Electric Cooperative Corporation (Arkansas Electric); National Rural Electric Cooperative Association (NRECA); Entergy Operating Companies[27] and Entergy Services, Inc. (together, Entergy); South Mississippi Electric Power Association (South Mississippi Association); the Municipal Energy Agency of Mississippi; Southwestern Electric Cooperative, Inc. (Southwestern); and the Mississippi Delta Energy Agency and its two members, the Clarksdale Public Utilities Commission of the City of Clarksdale, Mississippi and the Public Service Commission of the City of Yazoo City, Mississippi (Mississippi Delta Agency and Members).

11. On August 25, 2014, Indicated Capacity Suppliers[28] filed a motion for expedited action requesting that the Commission issue an order on rehearing in this proceeding as soon as possible. Indicated Capacity Suppliers argue that the results of a survey conducted in 2013 by MISO and the Organization of MISO States (MISO OMS Survey), coupled with MISO's colder than average weather during the winter of 2013-2014 that presented challenges to the electric and natural gas system, highlight the need for capacity market reform and the need for expedited consideration of the issues in this proceeding. Specifically, Indicated Capacity Suppliers contend that the MISO OMS Survey projected a shortfall of 2.3 GW in 2016 for MISO's Central and North regions and that more reasonable survey assumptions would reveal a higher shortfall than the

[27] Entergy Operating Companies are Entergy Arkansas, Inc.; Entergy Gulf States Louisiana, L.L.C.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; Entergy Texas, Inc.; and Entergy Services, Inc.

[28] Indicated Capacity Suppliers are Exelon; Dynegy, Inc.; and NextEra.

survey indicates. Indicated Capacity Suppliers assert that the North American Electric Reliability Corporation (NERC) also anticipates potential reserve requirement deficiencies in MISO, finding a potential capacity shortfall of 6.75 GW by 2016.[29] Indicated Capacity Suppliers generally urge the Commission to implement a capacity market construct as recommended by Capacity Suppliers in this proceeding.

12. Southern Indiana Gas and Electric Company (Southern Indiana), APPA and NRECA (APPA/NRECA), Joint Customers, Organization of MISO States, Coalition of Capacity Suppliers and Customers,[30] Midwest TDUs,[31] and Indiana Utility Regulatory Commission (Indiana Commission) filed answers in opposition to Indicated Capacity Suppliers' motion.

13. Ameren, Coalition of MISO Customers and Wisconsin Industrial Energy Group filed answers in support of Indicated Capacity Suppliers' motion.

14. MISO filed an answer to the Indicated Capacity Suppliers' motion, asking the Commission to consider relevant contextual information regarding the resource assessment survey and results discussed in the motion. MISO states that the survey is meant to provide transparency about what is currently known about future resource needs and supplies, to facilitate additional planning and actions. MISO states the Indicated Capacity Suppliers' motion could be construed to overstate the likelihood of a potential future reserve margin shortfall, based on the survey results. MISO states that, as is the case with all projections, there is a level of uncertainty associated with responses about demand and resources for future years, even if based on the best information known at the time. MISO states that LSEs are continuing to develop plans and make resource decisions for future years, including 2016, and therefore, the survey results should not be viewed as a definitive statement about what will happen in 2016 and beyond.

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[29] Indicated Capacity Suppliers Motion at 3 (citing NERC, *December 2013 Long-Term Reliability Assessment* 20, 52-70, *available at* www.nerc.com/pa/RAPA/ra/Reliabilty%20Asesments%20DL/2013_LTRA_FINAL.pdf.)

[30] The Coalition of Capacity Suppliers and Customers are NIPSCO, Duke Energy Indiana, Inc. (Duke), Hoosier and Southern Illinois, Alliant Energy Corp., and Xcel Energy, Inc.

[31] For purposes of this answer, Midwest TDUs consist of Great Lakes Utilities, Indiana Municipal Power Agency, Madison Gas & Electric Company, Midwest Municipal Transmission Group, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, and WPPI Energy.

15. On June 23, 2015, Great River Energy filed a motion for expedited action on its request for rehearing.

IV. **Briefing Procedures**

16. On August 12, 2013, the Commission issued an order initiating briefing procedures pursuant to Rule 713(d)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d)(2) (2013).[32] The Commission noted that the Market Monitor, in its request for rehearing, presented evidence suggesting that "a large share of the capacity requirements in MISO are satisfied via bilateral purchases, including purchases from outside MISO. Therefore, if capacity prices rise as capacity margins fall . . . states and regulated LSEs are likely to have the incentive to depress capacity prices."[33] The Commission also noted that Capacity Suppliers argued that approximately one-fourth of the generation in MISO is "merchant or non-utility affiliated."[34] The Commission found that it "would benefit in its further consideration of this matter by the receipt of briefs from parties in this proceeding addressing the matters raised in the requests for rehearing submitted by the Market Monitor and Capacity Suppliers with respect to the Commission's rejection of MISO's [MOPR]."[35]

17. Initial Briefs were filed by Capacity Suppliers; NRG; Midwest TDUs; Illinois Municipal; Indiana Commission; Southern Indiana; Organization of MISO States; Coalition of MISO Customers; Duke; Michigan Citizens; MidAmerican Energy Company (MidAmerican); American Municipal Power, Inc. (American Municipal) and the Michigan South Central Power Agency; Arkansas Electric, Mississippi Delta Agency and Members, the Municipal Energy Agency of Mississippi (Joint Customers); South Mississippi Association; Hoosier and Southern Illinois; APPA/NRECA; Indicated MISO Load Serving Entities;[36] Indianapolis Power & Light Company and Northern Indiana

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[32] *Midwest Indep. Transmission Sys. Operator, Inc.*, 144 FERC ¶ 61,125 (2013) (Order Initiating Briefing Procedures).

[33] *Id.* P 3 (quoting Market Monitor Request for Rehearing at 9).

[34] *Id.* (quoting Capacity Suppliers Request for Rehearing at 13).

[35] *Id.* at 4. The Organization of MISO States filed a request to extend the briefing schedule to provide 60 days for initial briefs and 45 days thereafter for reply briefs, which the Commission granted.

[36] The Indicated MISO Load Serving Entities are Alliant Energy Corporate Services, Inc.; Consumers Energy Company; Dairyland Power Cooperative; DTE Energy Company; Otter Tail Power Company; Wisconsin Electric; and Xcel Energy Services

(continued...)

Public Service Company (together, NIPSCO); and Southwestern. The Market Monitor filed an initial brief out-of-time and motion to accept initial brief out-of-time.

18. Reply Briefs were filed by MidAmerican; NRG; Coalition of MISO Customers; Midwest TDUs; Capacity Suppliers; Duke; Southern Indiana; the Organization of MISO States; Michigan Citizens; American Municipal and the Michigan South Central Power Agency; Joint Customers; Hoosier and Southern Illinois; APPA/NRECA; and NIPSCO.[37]

19. On November 26, 2013, the Independent Market Monitor for PJM Interconnection, LLC (PJM) filed an answer, motion for leave to answer, and motion to intervene out-of-time.[38]

V. <u>Procedural Matters</u>

20. We deny Hoosier and Southern Illinois's motion to reject the Market Monitor's request for rehearing. Hoosier and Southern Illinois argue that section 313 of the Federal Power Act (FPA) empowers only those entities that are aggrieved by an order issued by

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Inc.

[37] On December 3, 2013, NIPSCO filed an errata to its reply brief to clarify that a statement contained in its reply brief should be attributed to Dr. David Patton, MISO's Market Monitor, and not the Independent Market Monitor for PJM.

[38] The Independent Market Monitor for PJM states that the answer is solely for the purpose of clarifying the record. In particular, in its reply brief, NIPSCO attributed a statement from testimony at the September 25, 2013 technical conference in Docket No. AD13-7-000 to the Independent Market Monitor for PJM. The Independent Market Monitor for PJM clarifies that the testimony was provided by Dr. David Patton, MISO's Market Monitor, and not the Independent Market Monitor for PJM.

the Commission to apply for rehearing.[39] Hoosier and Southern Illinois contend that the Market Monitor is therefore prohibited from seeking rehearing in this case because the Market Monitor is not an aggrieved party as required by section 313.[40] According to Hoosier and Southern Illinois, the Commission has recently recognized that a party is aggrieved if it can show that it has both constitutional and prudential standing to challenge a Commission order.[41] According to Hoosier and Southern Illinois, the Market Monitor has not suffered an injury in fact that is concrete and particularized.[42] Specifically, Hoosier and Southern Illinois argue that the June 11 Order does not fix the Market Monitor's rights in any regard and does not command the Market Monitor to do or to refrain from doing anything.[43] Hoosier and Southern Illinois contend that the fact that the Market Monitor merely disagrees with the Commission's determination does not render the Market Monitor an aggrieved party.[44]

21. The Market Monitor is a party to this proceeding, having intervened in MISO's July 2011 filing. However, as noted by Hoosier and Southern Illinois, under section 313 of the FPA, only a party that has been aggrieved by a Commission order may file a request for rehearing.[45] In light of the Market Monitor's role in monitoring and evaluating the market outcomes and market rules to promote the efficiency and competitiveness of all markets in MISO, including the capacity market, and to ensure that we have considered all relevant factors that may have a bearing on our decision, we find it appropriate to consider the issues raised by the Market Monitor on rehearing.

22. When late intervention is sought after the issuance of a dispositive order, the prejudice to other parties and burden upon the Commission of granting the late intervention may be substantial. Thus, movants bear a higher burden to demonstrate good cause for granting such late intervention. We find that Arkansas Electric, NRECA,

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[39] Hoosier and Southern Illinois, Motion to Reject at 2 (citing 16 U.S.C. § 825l (2012)).

[40] *Id.* at 3.

[41] *Id.* (quoting *City of Tacoma, Wash.*, 135 FERC ¶ 61,155, at P 17 (2011)).

[42] *Id.* (citing *Tenneco, Inc. v. FERC*, 688 F.3d 1018 (5th Cir. 1982)).

[43] *Id.* at 4.

[44] *Id.* at 4-5.

[45] *See* 16 U.S.C. §§ 825*l*(a) and (b) (2012).

Entergy, South Mississippi Association, the Municipal Energy Agency of Mississippi, Southwestern, Mississippi Delta Agency and Members, Louisiana Energy and Power Authority, Conway Corporation, and the Independent Market Monitor for PJM have not met this higher burden of justifying their late interventions.[46]

23. In light of our decision to deny Louisiana Energy and Power Authority's and Conway Corporation's late motions to intervene, we will dismiss Louisiana Energy and Power Authority's and Conway Corporation's requests for rehearing. Because Louisiana Energy and Power Authority and Conway Corporation are not parties to this proceeding, they lack standing to seek rehearing of the June 11 Order under the FPA and the Commission's regulations.[47]

24. Rule 713(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d) (2015), prohibits answers to requests for rehearing. We will, therefore, reject the answer filed by Hoosier and Southern Illinois.

VI. Substantive Matters

25. The Commission denies rehearing and grants, in part, clarification, as discussed below, based on the record developed in this docket.[48]

A. Planning Resource Auction

1. June 11 Order

26. In the June 11 Order, the Commission rejected MISO's proposal to establish a mandatory forward capacity auction. The Commission explained that based on MISO's depiction of resource planning in the region as being founded upon bilateral arrangements, as well as MISO's stated intention of supplementing its existing resource adequacy construct, rather than replacing it, MISO had not justified the need for a

[46] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 102 FERC ¶ 61,250, at P 7 (2003).

[47] *See* 16 U.S.C. § 825(a) (2012); 18 C.F.R. § 385.713(b) (2015); *Southern Company Services, Inc*., 92 FERC ¶ 61,167 (2000).

[48] The determinations made by the Commission herein are based on the factual record developed in the present docket, and do not reflect developments that may have occurred subsequent to the time that the Commission was accepting pleadings and evidence in this docket.

mandatory auction. The Commission additionally directed MISO to address resource deficiencies without requiring a mandatory auction.[49] The Commission stated that, in order to encourage LSEs to procure sufficient resources, one option would be a deficiency charge designed to be similar to the currently effective Financial Settlement Charge in section 69.9 of Module E, which is based on the Cost of New Entry (CONE), with modifications to make the proposed charge appropriate for the annual term of the proposed auction.

2. **<u>Requests for Rehearing</u>**

27. Capacity Suppliers and NRG argue that the Commission failed to explain how the resource adequacy construct ultimately approved in the June 11 Order complies with the Commission's prior directives requiring MISO to "find a new 'permanent approach' 'that utilize[s] market mechanisms' 'to obtain sufficient local resources to ensure reliability.'"[50] Capacity Suppliers allege that the Commission has not provided a reasoned explanation of its decision to change course in the June 11 Order.[51] Capacity Suppliers also argue that the capacity construct approved by the Commission is unduly discriminatory because it requires sellers to participate but does not impose a reciprocal obligation on buyers.[52]

28. Capacity Suppliers further claim that, by approving a voluntary market in the MISO region based on the prominence of cost-of-service regulation, the Commission effectively abdicated its jurisdiction over the market to the various state regulatory agencies.[53] Capacity Suppliers contend that the Commission's jurisdiction is not discretionary, regardless of regional differences or the prevalence of cost-of-service regulation in the region. Capacity Suppliers state that, as a result, the Commission is statutorily obligated to ensure just and reasonable rates. Capacity Suppliers observe that,

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[49] June 11 Order, 139 FERC ¶ 61,199 at P 40.

[50] Capacity Suppliers Request for Rehearing at 32 (citing Locational Requirements Compliance Order, 131 FERC ¶ 61,228 at PP 23-24); NRG Request for Rehearing at 10.

[51] Capacity Suppliers Request for Rehearing at 32.

[52] *Id.* at 34.

[53] *Id.* at 39-41.

implicit in this obligation, is the requirement that the Commission protect states from the actions of other states.[54]

29. Capacity Suppliers and NRG also argue that the construct approved by the Commission "cannot fulfill the purposes of a capacity market, just like MISO's previous capacity markets."[55] Specifically, NRG contends that a voluntary capacity auction, paired with a vertical demand curve in the absence of buyer-side market power mitigation, will not produce economic signals to retain existing generation and incentivize new generation.[56] According to Capacity Suppliers, the primary purpose of a capacity market is to produce long-term economic signals that lead to the development of generating capacity sufficient to maintain system reliability. In order to achieve this end, Capacity Suppliers assert that clearing prices must average out over time to the CONE.[57] However, Capacity Suppliers state that the revenues in MISO's existing capacity construct have not achieved this measure and thus do not achieve the goal of making up the "missing money" for merchant resources.[58] In particular, Capacity Suppliers attribute this shortcoming to the voluntary nature of the auction approved by the Commission.[59] Capacity Suppliers further argue that the ultimate problem with the approved voluntary capacity construct is that resource adequacy will eventually be jeopardized.[60]

30. Capacity Suppliers also assert that any differences between MISO and other regions do not justify the Commission's holding in the June 11 Order.[61] Capacity Suppliers state that the Commission based its finding on the fact that MISO does not face the same degree of transmission and generation constraints as do other regions and LSEs in the MISO region utilize bilateral contracts and cost-of-service regulation to ensure

[54] *Id.* at 40-41 (citing *New York v. FERC*, 535 U.S. 1, 5-6 (2002); *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at P 3 (2011)).

[55] *Id.* at 33; NRG Request for Rehearing at 10.

[56] NRG Request for Rehearing at 10.

[57] Capacity Suppliers Request for Rehearing at 33.

[58] *Id.* at 34.

[59] *Id.* at 34-35.

[60] *Id.* at 35-36.

[61] *Id.* at 36-38.

resource adequacy, rather than retail-choice.[62] Capacity Suppliers urge that even the complete absence of any restraints in the MISO region would not justify approval of a voluntary auction because constraints are irrelevant to the most common gaming behavior.[63] Further, the share of capacity that is bilaterally procured is also irrelevant according to Capacity Suppliers.

31. Capacity Suppliers further assert that regional differences do not justify a voluntary capacity auction in MISO because, even if most of the capacity in the MISO region is subject to cost-of-service regulation, the Commission is still required by the FPA to ensure that suppliers in deregulated states and merchant generators are treated fairly.[64] Capacity Suppliers state that the Commission has historically recognized the benefits of competitive markets.[65] Moreover, Capacity Suppliers point out that some jurisdictions allow retail competition and that more states may adopt retail choice in the future. In this respect, Capacity Suppliers conclude that the June 11 Order "puts retail choice entities at a large disadvantage compared to utilities."[66]

32. NRG contends that the Commission erroneously substituted its preferred market construct in place of MISO's proposed construct in contravention of section 205 of the FPA.[67] NRG explains that pursuant to section 205, a filing utility has the burden of demonstrating that its proposal is just and reasonable and the Commission is prohibited from substituting a more just and reasonable provision in the place of a utility's just and reasonable proposal.[68] In particular, NRG states that the Commission rejected MISO's proposed mandatory auction without finding that the proposal was unjust and unreasonable, stating instead that the mandatory portion of the auction was unnecessary. Thus, NRG argues that the Commission unlawfully rejected MISO's proposal and substituted its judgment for that of the filing utility without bearing the burden of

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[62] *Id.* at 36 (citing June 11 Order, 139 FERC ¶ 61,199 at P 38).

[63] *Id.*

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

[65] *Id.* (citing *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 141 (2006)).

[66] *Id.* at 38.

[67] NRG Request for Rehearing at 9-10.

[68] *Id.* at 9.

demonstrating pursuant to section 206 of the FPA that the adopted proposal was just and reasonable.[69]

33. NRG and Capacity Suppliers contend that the Commission erred in approving a capacity construct that will allow capacity prices to close at or near zero.[70] Specifically, NRG argues that the Commission's rejection of MISO's proposed mandatory auction and MISO's proposed MOPR provisions, in conjunction with the Commission's approval of MISO's proposed vertical demand curve fails to meet the requirements of the FPA in two respects.[71] First, NRG contends that the Commission is obligated to approve a market designed with the goal of providing a reasonable opportunity to earn a return of, and on, equity.[72] NRG argues that by allowing clearing prices in MISO's planning resource auction to clear at levels at or near zero, the "capacity market in MISO does not meet the required market design."[73] In addition, NRG claims that the Commission's holding sanctions discrimination between traditional utilities and non-utility capacity suppliers. NRG explains that traditional utilities and non-affiliated capacity suppliers are both entitled to a reasonable opportunity to recover their full cost of service in addition to a reasonable return of equity.[74] However, NRG asserts that integrated utility sellers of capacity will receive a higher rate for capacity services than non-affiliated capacity suppliers because the former are guaranteed full cost-of-service rate recovery "backstopped by ratepayers."[75] Moreover, NRG contends that despite any differences in the composition of different regions, the requirement to ensure just and reasonable rates applies in all states.[76]

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[69] *Id.* (citing *W. Resources, Inc. v. FERC*, 9 F.3d 1568 (D.C. Cir. 1993)).

[70] *Id.* at 5-7; Capacity Suppliers Request for Rehearing at 25.

[71] NRG Request for Rehearing at 7-8.

[72] *Id.* at 7 (citing *Bridgeport Energy, LLC*, 113 FERC ¶ 61,311, at P 29 (2005) (Bridgeport) for the proposition that, with regard to the fixed capacity market, a just and reasonable fixed capacity market design requires that resources must be provided the opportunity to recover their costs).

[73] *Id.*

[74] *Id.* at 8.

[75] *Id.* at 7-8.

[76] *Id.* at 13.

34. NRG further argues that "the Commission failed to develop the requisite factual record to determine whether a capacity market with prices at or near zero, combined with an energy market with price caps, gives a supplier a reasonable opportunity to recover its capital investment and other fixed costs over its expected lifetime."[77]

3. Commission Determination

35. For the reasons discussed below, we deny rehearing. As a preliminary matter, we disagree with Capacity Suppliers' and NRG's assertion that the voluntary capacity construct approved in the June 11 Order was not in compliance with the Commission's directives. The prior Commission orders made no mention of the voluntary capacity construct, and therefore they are incorrect in stating that the Commission ordered MISO to change it.[78]

36. The Commission directive to develop a permanent approach, referenced by Capacity Suppliers, refers to a directive to address congestion that limits aggregate deliverability in the resource adequacy markets.[79] In response, MISO provided a locational market mechanism that evaluates deliverability in its July 2011 filing that the Commission accepted in the June 11 Order, thereby satisfying the Commission's compliance requirement,[80] as discussed more fully in this order.[81] We affirm the decision in the June 11 Order to reject MISO's proposed mandatory auction. As the Commission explained in the June 11 Order, MISO has the burden of supporting its proposal as just and reasonable and not unduly discriminatory or prejudicial.[82] The Commission determined that MISO had not met this burden.[83]

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[77] *Id.*

[78] Capacity Suppliers Request for Rehearing at 32.

[79] *See* Locational Requirements Order, 126 FERC ¶ 61,144 at P 47.

[80] June 11 Order, 139 FERC ¶ 61,199 at P 84.

[81] *See infra* section VI.F.

[82] June 11 Order, 139 FERC ¶ 61,199 at P 37.

[83] *Id*. P 40 ("Based on MISO's depiction of resource planning in its footprint to be based largely on bilateral arrangements [footnote deleted], as well as its intent to only supplement the current resource adequacy plan, rather than transform it into a mandatory forward capacity process [footnote deleted], MISO has not justified the need for a

(continued...)

37. More specifically to NRG's position, as we recently explained in the PJM MOPR Rehearing Order,[84] we recognize that under FPA section 205 and section 4, the comparable provision of the Natural Gas Act (NGA),[85] our authority permits us to accept or reject a proposal submitted by the utility depending upon whether the utility has carried its burden of proof to show that its proposal is just and reasonable. As such, we cannot impose on the utility significant changes, without satisfying our burden under section 206, or NGA section 5, to find the existing tariff provisions unjust and unreasonable.

38. Nonetheless, an applicant that fails to satisfy its burden to show that its FPA section 205, or NGA section 4, proposal is just and reasonable may prefer to implement its proposal with the changes necessary to make that proposal just and reasonable rather than continue to operate under its existing just and reasonable tariff. Accordingly, the Commission, in exercising its FPA section 205 and NGA section 4 authority, has utilized a long standing practice of accepting filings conditioned on the utility or pipeline revising its proposal, when the Commission finds the filing generally just and reasonable, but further determines that certain components of the filing are not just and reasonable. The Commission adopted this approach given the complexity of FPA section 205 and NGA section 4 filings, which, like the proposal submitted here by MISO, may consist of numerous inter-related tariff revisions. In these circumstances, a conditional acceptance serves the need for administrative efficiency by avoiding the necessity of rejecting the filing in its entirety.

39. However, as we emphasized in the PJM MOPR Order, the Commission is not improperly imposing those conditions under FPA section 205 or NGA section 4. The Commission, rather, is finding only that the filing has not been shown to be just and reasonable as filed, unless the utility or pipeline makes the revisions identified by the Commission. Accordingly, the utility or pipeline is free to indicate that it is unwilling to accede to the Commission's conditions by withdrawing its filing and returning to the use of its prior rate. As the U.S. Court of Appeals for the District of Columbia Circuit found in *City of Winnfield v. FERC*,[86] the Commission can revise a rate proposal under section

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mandatory auction.").

[84] *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,066, at P 15 (2015) (PJM MOPR Rehearing Order).

[85] 15 U.S.C. § 717c (2012).

[86] 744 F.2d 871 (D. C. Cir. 1984) (*City of Winnfield*).

205 as long as the utility "accepts" the change.[87] The court recognized, as has the Commission, the administrative convenience of not having to reject a filing only to have the utility refile to signify its acceptance later:

> It would be empty formalism to strike down those rates solely because they were initially introduced into the proceeding by Commission staff rather than the utility itself. And it would be wasteful to require, instead of the sensible procedure adopted here, that the Commission first deny LP&L's requested increase and that the utility then commence a separate § 205 proceeding proposing the acceptable increase of rates under the existing scheme that the Commission staff had suggested.[88]

In *Western Resources*, the court similarly recognized the Commission's ability to act under section 205 or section 4 when the utility or pipeline "consents" to the change.[89]

40. In line with the sensible procedure in *City of Winnfield*, the conditional acceptance process utilized by the Commission gives the utility or pipeline an opportunity, through a compliance filing, to cure the problems the Commission has found in its filing, without having its entire filing rejected. As long as the utility or pipeline accepts the condition, this process allows its section 205 or section 4 filing to take effect, without the delay and administrative difficulties attributable to the submission of a new FPA section 205 filing or NGA section 4 filing to cure the problems identified by the Commission.

41. The Commission has recognized that, with the consent of the public utility or interstate natural gas pipeline, it may implement, under FPA section 205 and NGA section 4, provisions that differ from those initially proposed. In a proceeding instituted by ISO New England Inc. (ISO-NE), for example, the Commission found that it had properly acted under section 205 in requiring ISO-NE to utilize one of three rate design options, as outlined in the pleadings, each of which ISO-NE had made clear it would accept.[90] The Commission noted that, "[w]hile ISO-NE [had] not propose[d] the three-

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[87] *Id.* at 875.

[88] *Id.*

[89] *See Western Resources, Inc. v. FERC*, 9 F.3d 1568, at 1579 (D.C. Cir. 1993) (*Western Resources*).

[90] *ISO New England, Inc.*, 106 FERC ¶ 61,294, *order on reh'g*, 108 FERC ¶ 61,138 (2004), *order on remand, ISO New England, Inc*., 113 FERC ¶ 61,055 (2005).

tiered rate design in its initial filing, [its] acceptance of this rate design . . . established that [it] has not been imposed unwillingly on the utility under section 206."[91]

42. The Commission similarly permits utilities and pipelines that are unwilling to consent to the Commission's conditional acceptance of their filings to withdraw those filings and thus retain the effectiveness of their existing tariffs. In *PJM Interconnection, L.L.C.*,[92] the Commission, after conditionally accepting a filing by American Electric Power Service Corporation (AEP), subject to hearing and settlement judge procedures, permitted AEP to withdraw its filing and terminate the proceeding, given that "AEP no longer support[ed] its [FPA] section 205 filing rate increase filing, and because no charges [had been] assessed . . . under the proposed formula rate filing."[93] Similarly, in *Columbia Gulf Transmission Company*,[94] the Commission accepted a filing subject to a technical conference and the pipeline later moved to withdraw the proposal, which the Commission accepted. The Commission explained: "since Applicants are not required to offer the proposed [rate] service, and are not prepared to support their proposed tariff sheets, applicants may withdraw the [relevant] tariff sheets."[95]

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[91] *Id.* P 27. *See also Municipal Defense Group v. FERC*, 170 F.3d 197, 201 (D.C. Cir. 1999) (finding that a pipeline, which had submitted multiple tariff options, but had not withdrawn its initial tariff option, which the Commission accepted, remained the proponent of that initial option under NGA section 4).

[92] 143 FERC ¶ 61,009 (2013).

[93] *Id*. P 3.

[94] 127 FERC ¶ 61,059 (2009).

[95] *Id*. P 19. *See also Texas Gas Transmission Corp.*, 100 FERC ¶ 61,126 (2002) (accepting and suspending filing subject to conditions and outcome of technical conference), *order on technical conference*, 101 FERC ¶ 61,408 (2002) (imposing conditions), Docket Nos. RP02-378-000 (July 18, 2003) (delegated letter order) (accepting withdrawal of tariff provisions); *Columbia Gas Transmission Corp.*, Docket No. RP00-374-002 (April 2, 2001) (delegated letter order) (accepting withdrawal of a tariff filing where the pipeline did not agree with the Commission's condition); *Columbia Gulf Transmission Co.*, 132 FERC ¶ 61,134 (2010) (permitting the pipeline to submit a new filing to reinstate its prior just and reasonable rates where the pipeline was unwilling to accept Commission's conditions, as applicable to the filing at issue, and thus elected to withdraw its filing). *See also Columbia Gulf Transmission Co.*, 134 FERC ¶ 61,194 (2011) (rejecting a filing when the pipeline filed for rehearing disagreeing with the Commission's interpretation of its tariff).

43. Here, MISO's Tariff, as of the date of MISO's filing, provided for a regional monthly resource adequacy construct, with MISO's filing proposing to establish a mandatory construct, including an annual zonal auction, among other changes. In the June 11 Order, the Commission determined that MISO had not demonstrated that its proposed mandatory auction for deficiencies was just and reasonable. In its filing, MISO stated that its proposal was only intended to supplement the current resource adequacy plan that the Commission had determined was just and reasonable. In light of the fact that LSEs would continue to meet their resource requirements mostly through owned resources or bilateral arrangements and the auction would continue to play a residual balancing role – just the same as under the existing voluntary construct – the Commission determined that MISO had not provided an adequate basis for such a significant change to the structure of the resource adequacy construct. The Commission therefore accepted MISO's filing conditioned on MISO's retention of its current just and reasonable voluntary construct.[96]

44. We clarify, however, that this action was not taken pursuant to section 206 given that the Commission did not find the then-existing regional monthly resource adequacy construct unjust and unreasonable. The conditional acceptance pursuant to section 205 provided MISO with the opportunity to move forward with the rest of its filing while retaining the just and reasonable voluntary resource adequacy construct. Based on the fact that MISO neither sought rehearing of the June 11 Order, nor submitted a request to withdraw its filing, and that MISO submitted its compliance filing to retain the voluntary resource adequacy construct, it appears that MISO has consented to the Commission's condition. Nonetheless, given the requests for rehearing on this issue and the unique facts and circumstances of this case, and to avoid any possible confusion as to MISO's acceptance of the voluntary construct condition, MISO must file a notice within 30 days of the date of this order if it determines to withdraw its filing.

45. We note that MISO's filing in Docket No. ER11-4081-000 fulfilled certain compliance obligations. Specifically, in the Locational Requirements Order, the Commission explained "that a more robust and permanent approach to addressing congestion that limits aggregate deliverability is ultimately required."[97] In order to

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[96] June 11 Order, 139 FERC ¶ 61,199 at PP 1, 40. *See also City of Winnfield*, 744 F.2d at 875 ("the structure of the [FPA]. . . is not 'undermined' or even threatened when, in a § 205 proceeding, the Commission declines to permit a new form of rate calculation but grants a rate increase under the form the utility had previously been using, which increase the utility accepts.").

[97] Locational Requirements Order, 126 FERC ¶ 61,144 at P 47.

resolve these deliverability concerns, the Commission directed MISO to evaluate locational capacity requirements in other regions to ensure sufficient capacity is available in import-restricted zones to satisfy the planning reserve margin. Further, in the Locational Requirements Order, the Commission directed MISO to "inform the Commission . . . what steps are being taken to develop a more permanent approach."[98] The Commission subsequently rejected MISO's filing submitted in compliance with the Locational Requirements Order because MISO had failed to address aggregate deliverability in the region.[99] Thus, the Commission clarified that the Locational Requirements Order requires MISO to "develop a plan that details the steps that will be taken to incorporate [locational] market mechanisms into the Resource Adequacy Plan."[100] Were MISO to file a notice noting its determination to withdraw its filing in Docket No. ER11-4081-000, it would still be obligated to fulfill these compliance obligations in a filing due to the Commission within 30 days of the date of this order, as the issue of the propriety of the earlier required compliance filings had not been raised.

46. We turn now to the merits of the rehearing arguments regarding the Commission's conditional acceptance of MISO's proposed reforms to its resource adequacy construct. As a threshold matter, we find that Capacity Suppliers and NRG have not demonstrated that the Commission should grant rehearing and require a mandatory capacity auction for the MISO region. We affirm that, based on the record before us, MISO's resource adequacy construct is appropriate for the primarily vertically-integrated MISO region, which does not require a forward mandatory capacity market to produce just and reasonable rates. The need for new capacity in MISO is driven by a variety of considerations, including, but not limited to, state resource planning and the opportunity to recover costs from the energy, ancillary services, and capacity markets. Accordingly, ensuring resource adequacy in the MISO region will be a product of a wide range of factors in addition to the auction clearing prices, such as market prices for other energy and reserve products, the terms of bilateral arrangements, and state regulatory resource planning. This market and regulatory framework, with the largely vertically-integrated nature of the MISO region, has provided the basis for resource sufficiency in MISO for a significant period of time, and therefore there appears to be no need on the basis of this record to require a mandatory auction to manage resource adequacy.

47. We disagree with Capacity Suppliers' claim that MISO's resource adequacy plan without a mandatory requirement is unduly discriminatory because it requires sellers to

[98] *Id.*

[99] Locational Requirements Compliance Order, 131 FERC ¶ 61,228 at P 23.

[100] *Id.* P 24.

participate but buyers do not have such an obligation. LSEs, as buyers of resources, must obtain sufficient resources to meet their planning resource margin requirement or pay a significant penalty of 2.748 times CONE.[101] We do not consider this requirement and its associated penalty to be a "free pass," as characterized by Capacity Suppliers, or that buyers have no incentive to purchase capacity, as NRG claims.[102]

48. We also disagree with Capacity Suppliers' claim that the Commission is abdicating its jurisdiction over the wholesale capacity market in MISO. As the discussion in the June 11 Order and this order makes clear, we have examined the justness and reasonableness of the MISO resource adequacy construct. The continuing role of state agencies in the planning process in no way constitutes an abdication of the Commission's obligations.

49. We interpret one of Capacity Suppliers' points to be that the Commission abdicated its jurisdiction by allowing for a continuation of a voluntary capacity auction that is unjust and unreasonable because it can be gamed by states and LSEs.[103] NRG makes a similar point when it argues that unmitigated market power will artificially lead to continued low capacity prices and unjust and unreasonable rates for independent power producers.[104] We consider these assertions to be unsupported on the record. As discussed more fully in section VI.B, the Commission found in the June 11 Order, and we affirm in this order, that the record does not reflect evidence of price suppression or an incentive to suppress prices such that buyer-side market power mitigation is required.

50. We are not persuaded that a mandatory centralized capacity auction construct is necessary to ensure resource adequacy in the MISO region. Such assertions are unsupported given that utilities in MISO have historically procured sufficient capacity to meet their needs.

51. Nor do we consider the MISO construct to be unjust or unreasonable because it does not provide a price equal to the CONE. As market prices, the zonal auction clearing prices reflect the supply-demand dynamics in MISO's region. The record in this case shows that the MISO region had a significant capacity surplus, as discussed above, and

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[101] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 153 FERC ¶ 61,230, at PP 25-30 (2015).

[102] NRG Request for Rehearing at 6.

[103] Capacity Suppliers Request for Rehearing at 41.

[104] NRG Request for Rehearing at 6.

the auction clearing prices reflect this reality. Accordingly, we do not consider these prices to necessarily be defective price signals simply because the MISO construct has not yielded prices equal to the CONE.

52. We disagree with Capacity Suppliers' contention that regional differences between the MISO region and other capacity markets do not justify the resource adequacy construct that the Commission approved for MISO. On the contrary, the predominance of vertically-integrated LSEs and long-term bilateral arrangements for obtaining capacity are key MISO region characteristics underlying the Commission's determination that there are no demonstrated incentives for the price-suppression behavior of concern to Capacity Suppliers and NRG. These regional factors therefore play a significant role in the Commission's determination that MISO's wholesale capacity market, as approved by the Commission, is just and reasonable. Also, the fact that many resources in MISO are receiving cost-of-service cost recovery in addition to compensation from wholesale markets is a factor in the Commission's determination that there are sufficient incentives to attract new resources, as discussed above.

53. We also find no basis for NRG's contention that the June 11 Order sanctions discrimination between traditional utilities and non-utility capacity suppliers. The record in this proceeding shows that non-utility capacity suppliers typically sell to local utilities via long-term power purchase agreements.[105] The cost of these agreements is being recovered by utilities in their cost-of-service filings with state regulators. Therefore, NRG receives similar opportunities for recovery that traditional utilities receive. Furthermore, NRG provides no explanation for its statement that utility sellers receive a higher rate for the capacity services they provide than non-affiliated capacity suppliers.[106] Accordingly, we consider the capacity construct approved by the Commission in the June 11 Order to be consistent with precedent.[107]

[105] *See* Midwest TDUs Initial Brief at 15-18.

[106] NRG Request for Rehearing at 8.

[107] *Bridgeport*, 113 FERC ¶ 61,311 at P 29 (stating that "in a competitive market, the Commission is responsible only for assuring that Bridgeport is provided the *opportunity* to recover its costs").

B. Buyer-Side Market Power Mitigation and the Minimum Offer Price Rule

1. June 11 Order

54. In the June 11 Order, the Commission rejected MISO's proposed MOPR, explaining that MISO had not demonstrated the need for buyer-side market power mitigation in the MISO region. Specifically, the Commission observed that traditional utilities in the region own the vast majority of capacity, and therefore, would not significantly benefit from lower prices in MISO's voluntary capacity market. The Commission observed that, as a result, states in MISO would not have the incentive to exercise buyer-side market power. Additionally, the Commission explained that, due to the numerous flaws in MISO's proposal, MISO's proposed MOPR provisions would be ineffective in deterring the exercise of buyer-side market power.[108]

2. Requests for Rehearing

55. Capacity Suppliers, Demand Response Supporters, and NRG argue that the Commission erred in directing MISO to remove its MOPR provisions.[109] The Market Monitor also encourages the Commission to reconsider its decision to require removal of the MOPR provisions.[110] Specifically, Capacity Suppliers argue that the Commission's rejection of the MOPR proposed by MISO contradicts the FPA, Commission precedent, and ignores record evidence.[111] Capacity Suppliers state that due to the direct effect of buyer-side market power on capacity rates, the Commission's rejection of the MOPR abdicates its statutory responsibility to ensure just and reasonable rates.[112] Capacity Suppliers assert that the Commission's rejection of the MOPR fails to treat buyer-side and seller-side market power equivalently.[113] Additionally, Capacity Suppliers and NRG

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[108] June 11 Order, 139 FERC ¶ 61,199 at PP 66-68.

[109] Capacity Suppliers Request for Rehearing at 8; Demand Response Supporters Request for Rehearing at 5-6; NRG Request for Rehearing at 12.

[110] Market Monitor Request for Rehearing at 9.

[111] Capacity Suppliers Request for Rehearing at 8.

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

[113] *Id.* at 9-10 (citing *Weyerhaeuser Co. v. Ross-Simmons Hardwood Lumber Co.*, 549 U.S. 312, 321-22 (2007); *Energy Transfer Partners, L.P.*, 120 FERC ¶ 61,086, at P 31 (2007)).

argue that the Commission failed to follow its own precedent imposing and enhancing buyer-side market power mitigation in neighboring regions.[114] NRG argues that the Commission has historically recognized that buyer-side market power mitigation rules are critical to developing a successful resource adequacy construct.[115] Capacity Suppliers argue that the Commission failed to consider substantial evidence in the record demonstrating the unjust and unreasonable effect on rates of unmitigated uneconomic entry.[116]

56. Capacity Suppliers also assert that regional differences do not justify the purported failure to mitigate buyer-side market power.[117] In particular, Capacity Suppliers argue that the Commission's reliance on regional differences ignores the obvious effect of capacity auction prices on bilateral prices. Thus, Capacity Suppliers point out that any entity which needs to procure more capacity than it sells will benefit from lower capacity prices in the capacity auction.

57. Furthermore, Capacity Suppliers contend that the Commission's ruling also ignores the impact of unmitigated capacity prices on the minority of parties that rely upon the capacity market.[118] Capacity Suppliers state that while the vast majority of capacity in MISO is owned by utilities that do not need to procure significant amounts of capacity from MISO's capacity market, a significant amount of capacity in MISO is not owned by traditional utilities. Capacity Suppliers submit that approximately one-fourth of the generation in MISO is "merchant or non-utility affiliated."[119]

58. Further, Capacity Suppliers argue that the FPA does not allow for discrimination against anyone, even if they are in the comparative minority.[120] Capacity Suppliers add

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[114] *Id.* at 10-11 (citing *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,022, at P 141 (2011)); NRG Request for Rehearing at 12.

[115] NRG Request for Rehearing at 12 (citing *ISO New England, Inc.* and New England Power Pool Participants Committee, 135 FERC ¶ 61,029, at P 158 (2011)).

[116] *Id.* at 11-12 (citing Capacity Suppliers' Motion to Intervene and Protest, Affidavit of Dr. Roy J. Shanker (Shanker Aff.), at 38).

[117] *Id.* at 12-13.

[118] *Id.* at 13-16.

[119] *Id.* at 13.

[120] *Id.* (citing *Dynegy Midwest Generation, Inc.*, 633 F.3d 1122, 1127 (D.C.

(continued...)

that the Commission's holding in this case is inconsistent with its treatment of the issue in the PJM region. Capacity Suppliers state that the Commission has previously rejected proposals to exempt state-sponsored uneconomic entry from mitigation because allowing the exercise of buyer-side market power would disrupt competitive price signals that the region, including other states, rely on.[121] Capacity Suppliers also point out that while it is unclear what effect the absence of buyer-side market power mitigation would have on capacity markets, strong mitigation provisions would have no effect on the market if no buyers actually attempt to exercise buyer-side market power.[122] On the other hand, Demand Response Supporters assert that permitting uneconomic new resources to offer into MISO's capacity auction will lead to market price distortions and suppressed market-wide clearing prices. As a result, according to Demand Response Supporters, the ability of demand response resources to participate at a reasonable price will be limited.[123]

59. Capacity Suppliers and Demand Response Supporters argue that the Commission should adopt just and reasonable tariff provisions that mitigate buyer-side market power. Demand Response Supporters urge the Commission to direct MISO to develop buyer-side market power mitigation provisions that will subject uneconomic new resources to mitigation and set the MOPR at 100 percent of net CONE.[124] Likewise, Capacity Suppliers argue that effective mitigation measures include the following features: (1) all new entry should be screened for offer prices below 100 percent of levelized net CONE; (2) mitigation should apply to all resource types; (3) any resources that fail the appropriate screens and are not otherwise exempt should be mitigated to 100 percent of the lesser of net CONE or unit-specific net CONE; (4) mitigation should apply to self-supply if it fails the above screens and the effective waiver for self-supply under the fixed resource adequacy plan should be eliminated; and (5) there should be a general exemption for all supply that either relies only on market revenues or that has received outside revenues only through a non-discriminatory procurement process.[125]

Cir. 2011)).

[121] *Id.* at 14.

[122] *Id.* at 15.

[123] Demand Response Supporters Request for Rehearing at 5-6.

[124] *Id.*

[125] Capacity Suppliers Request for Rehearing at 15-16.

60. According to the Market Monitor, the Commission's decision was based on findings that states and market participants in MISO will not have the incentive to lower capacity prices and that the MOPR provisions proposed by MISO were flawed in ways that would render them ineffective. The Market Monitor argues that market participants in fact may have incentive to depress prices as capacity prices rise and capacity margins fall. The Market Monitor also contends that such incentives will be magnified in a locational market structure because capacity prices in a local zone with limited surplus will be more sensitive.[126]

61. The Market Monitor also believes that the fact that the proposed MOPR provisions are flawed provides no basis for eliminating them unless the flaws cannot be remedied. The Market Monitor argues that the flaws in MISO's proposal can be remedied. The Market Monitor adds that the Commission has the authority to order modifications to the provisions that would fully address these concerns and that the record contained no evidence that would suggest that the MOPR provisions are unnecessary.[127]

3. Additional Briefing

a. Initial Briefs in Favor of MOPR

62. With respect to the MOPR, the Market Monitor asks the Commission to consider the question, "Is the purpose of the capacity market to provide price signals… to facilitate the efficient investment, retirement, and maintenance decisions that will satisfy MISO's resource adequacy needs?"[128] The Market Monitor asserts that if the answer is "no," the Commission has no reason to consider a MOPR in MISO. The Market Monitor argues that, if the answer is "yes," the MOPR alone will not achieve this objective.

63. NRG points out that part of the basis for the Commission's decision in the June 11 Order was "regional differences" between MISO and the Eastern regional transmission organizations (RTO). NRG notes that the 30 percent of MISO generation provided by merchant generators is critical to maintaining an acceptable reserve margin. It concludes that the current market structure lacks a robust and transparent means of incenting these resources to remain viable.[129]

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[126] Market Monitor Request for Rehearing at 9.

[127] *Id.* at 10-11.

[128] Market Monitor Initial Brief at 2.

[129] NRG Initial Brief at 3-4.

64. NRG argues that a well-designed wholesale market is indifferent to the underlying retail structure. NRG contends that ratepayers of integrated utilities are not disadvantaged by a competitive procurement mechanism that includes a MOPR. Further, it asserts that a functional resource adequacy market will increase competition and ensure the least-cost means of ensuring reliability. NRG asserts that arguments that ratepayers benefit from integrated utilities overspending for more expensive resources should be viewed with skepticism.[130]

65. NRG also contends that the June 11 Order did not address the interplay between the bilateral market and the Commission's centralized resource adequacy construct. NRG argues that by allowing LSEs to insert new, unmitigated entry into the market or take capacity out of the market by bidding in less than their total load, net long resources can exercise buyer-side market power. According to NRG, not only are competitive suppliers in MISO denied just and reasonable rates from the MISO centralized resource adequacy construct, but they are also denied any realistic opportunity to recover their costs in the bilateral market. In contrast, Capacity Suppliers argue that the amount of bilateral contracting is irrelevant to the decision of whether to mitigate buyer-side market power in the wholesale capacity market. They contend that even if entities buy only a small amount of capacity at auction, those prices still influence bilaterally-negotiated capacity prices.[131]

66. NRG and Capacity Suppliers also disagree with the contention that buyer-side market power mitigation rules are appropriate for Eastern RTOs, but not for MISO. NRG points out that, although PJM's footprint includes both integrated and non-integrated states, the Reliability Pricing Model rules apply to all market participants. NRG argues that the Commission should ensure some minimum level of consistency between key capacity market features in different markets.[132] NRG also asserts that the Commission has recognized the importance of buyer-side market power mitigation for successful markets.[133] Capacity Suppliers assert that there is no evidence from the experience of bilateral contracting in Eastern RTOs to suggest that a mandatory capacity market with

[130] *Id.* at 4.

[131] Capacity Suppliers Initial Brief at 5 (citing *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 95 FERC ¶ 61,418, at P 6 (2001)).

[132] NRG Initial Brief at 5.

[133] *Id.* at 6 (citing *ISO New England, Inc. and New England Power Pool Participants Committee,* 135 FERC ¶ 61,029 at P 158 and *PJM Interconnection L.L.C.*, 135 FERC ¶ 61,022, at P 195 (2011)).

strong buyer-side market power mitigation impedes bilateral contracting. To the contrary, Capacity Suppliers argue that a robust and efficient capacity market sends accurate price signals that assist efficient bilateral market contracting.[134]

67. NRG contends that allowing LSEs to purchase only a portion of their resource adequacy needs from the auction presents large buyer-side market power problems. NRG argues that, consequently, sellers are required to offer 100 percent of their capacity into the market, but buyers are not required to buy from the market at all, leading to the potential for buyer-side market power where there are a limited number of buyers and denying owners of merchant capacity any opportunity to earn a just and reasonable return.[135]

68. NRG argues that the current discrepancies between MISO and PJM market designs are creating inefficient outcomes. NRG states that entities in MISO are fleeing the market to sink capacity in PJM. NRG contends that the supply and demand conditions in the two markets are not markedly different; the market design accounts for the 27-fold difference in prices for capacity between the two RTOs. NRG asserts that this pricing paradigm causes societal waste because it results in generators in the areas south and west of PJM procuring firm transmission service into PJM through MISO in order to participate in PJM's market. NRG also contends that the capacity price vacuum in MISO is causing problems in PJM, which has expressed concern of whether it is capable of accepting a large number of cross-border capacity offers and maintaining a reliable and robust system.[136]

69. Finally, NRG contends that the entry of Entergy into MISO's footprint provides additional impetus for the Commission to revisit its decision. According to NRG, historically, the Entergy region has not been friendly to merchant developer interest, with most recent merchant generators in the region being sold to Entergy for "pennies on the dollar." NRG contends that providing Entergy the option to self-build new capacity and bid that capacity into the market at zero price would inhibit the ability of merchant generators to justify making additional large-scale capital investments into the Entergy region and result in inaccurate price signals in the broader MISO market.[137]

[134] Capacity Suppliers Initial Brief at 5.

[135] NRG Initial Brief at 10.

[136] *Id.* at 10-11.

[137] *Id.* at 12-13.

70. Capacity Suppliers argue that the Commission must prevent undue discrimination and ensure that prices are just and reasonable, regardless of the amount of merchant generation. Capacity Suppliers reiterate that about one-fourth of generation in MISO is non-regulated. Capacity Suppliers also contend that if the amount of merchant generation was so inconsequential as to need no protection from buyer-side market power, then it should also be too small to exert seller market power and there would be no need for seller market power mitigation.[138]

71. Capacity Suppliers agree that the Commission should not adopt MISO's originally proposed MOPR, but reiterate the argument in their rehearing request, described above, that the Commission should have revised the MOPR.[139]

72. Finally, Capacity Suppliers urge the Commission to act quickly to reform the MISO resource adequacy construct because of increasing resource adequacy concerns, including lower capacity margins.[140] They point to the near-zero capacity prices, increasing exports to PJM and the closure of the 556 MW Kewaunee nuclear plant, which relied on capacity revenues. Capacity Suppliers also contend that the few large resources in MISO that are ready to come online all appear to be state-sponsored resources or recipients of significant state subsidies and that, without a MOPR, these resources will suppress capacity prices paid to existing resources.[141]

b. Initial Briefs Opposing MOPR

73. Numerous parties support the Commission's rejection of MISO's proposed MOPR and ask the Commission to deny rehearing of that determination.[142] Generally, these parties allege that: (1) the MISO region is different than Eastern RTOs in which the

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[138] *Id.* at 6-7.

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

[140] *Id*. at 15 (citing MISO, *2013 Post Summer Assessment, Supply Adequacy Working Group Presentation* 3 (Oct. 3, 2013), https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2013/20131003/20131003%20SAWG%20Item%2005%202013%20Post%20Summer%20Assessment.pdf.).

[141] *Id.*

[142] American Municipal and the Michigan South Central Power Agency Initial Brief at 9; Southern Indiana Initial Brief; Duke Initial Brief.

Commission accepted MOPR proposals, as the MISO region is comprised primarily of traditional, vertically-integrated utilities; (2) these utilities lack an incentive to exercise buyer-side market power; (3) their construction of new generating facilities through their traditional, state-regulated processes does not constitute an exercise of buyer-side market power; and (4) the acceptance of a MOPR in the MISO capacity auction would cause significant harm to customers in the MISO footprint.

74. Several parties argue that the MISO region, unlike Eastern RTOs, is largely comprised of traditional obligation-to-serve utilities without restructured retail markets, which enables LSEs and regulators in the region to undertake longer-term commitments to generation resources, either in the form of direct construction by incumbent LSEs or through comparable long-term contracts.[143] For example, Midwest TDUs agree with the Commission's conclusion that LSEs in MISO continue to own the vast majority of the region's generation. They argue that LSEs typically procure long-term resources via contract, even where they do not directly own a generating facility.[144]

75. Parties also argue that the Commission, by rejecting the MOPR, properly recognized the scope of state and Commission authority over resource adequacy.[145] Numerous parties emphasize the critical role that state regulators play in ensuring resource adequacy in the MISO footprint through integrated resource planning, and note that regulators and LSEs in the region establish their portfolios to meet additional goals beyond simply lowest-cost reliability (e.g., managing fuel diversity and risk, reliability concerns, economies of scale, satisfying renewable portfolio requirements, and addressing locational and associated risks).[146] For example, Midwest TDUs argue that it is by design that LSEs in MISO are unlikely to find themselves significantly net short from a resource adequacy perspective.[147] Parties assert that adopting a MOPR would wrongly redefine capacity as a fungible commodity and diminish benefits that might

[143] *E.g.*, Organization of MISO States Initial Brief at 10-12.

[144] Midwest TDUs Initial Brief at 9-12; *see also* MidAmerican Initial Brief at 16-17.

[145] *E.g.*, Organization of MISO States Initial Brief at 7-10.

[146] *E.g.*, Midwest TDUs Initial Brief at 12; Organization of MISO States Initial Brief at 10-12.

[147] Midwest TDUs Initial Brief at 12.

drive an investment in a new generating facility, such as the ability to meet a renewable portfolio standard obligation.[148]

76. Parties further argue that the MISO capacity auction is residual in nature, which enables LSEs to economically address mismatches between their resource procurement and each year's zonal Planning Reserve Margin.[149] Several parties emphasize that the overwhelming majority of capacity needed to satisfy resource adequacy requirements is procured outside of the MISO capacity auction through either self-supply or bilateral contracts.[150] Parties similarly argue that there is no evidence that LSEs and their state regulators, who have historically addressed anticipated capacity shortages through the traditional regulatory model, have been rendered unable to reliably serve customers in the future.[151]

77. Many commenters question the accuracy or significance of Capacity Suppliers' assertion that approximately one-fourth of the generation in MISO is merchant or non-utility affiliated. NIPSCO notes that Capacity Suppliers fail to identify how much of this amount is supported by long-term bilateral contracts,[152] and Midwest TDUs argue that Capacity Suppliers have failed to provide any support for this assertion. Midwest TDUs further argue that it would be wrong to look at the amount of capacity owned by non-utility generators and assume that those resources are uncommitted merchant generation surviving on MISO capacity market revenues or short-term bilateral contracts. Midwest TDUs provide evidence that a substantial share of the non-utility generation in MISO, including a significant portion of Capacity Suppliers' own generation,[153] is under long-

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[148] *E.g.*, APPA/NRECA Initial Brief at 14-16.

[149] *E.g.*, MidAmerican Initial Brief at 22-24.

[150] *E.g.*, Indicated MISO Load Serving Entities Initial Brief at 6-10; NIPSCO Initial Brief at 13-14 (noting that, in the first Planning Resource Auction for the 2013-2014 Planning Year, 96 percent of offers were either submitted as part of a fixed resource adequacy plan or were self-scheduled (i.e., required to offer at $0/MW-day)); APPA/NRECA Initial Brief at 20.

[151] *E.g.*, MidAmerican Initial Brief at 19.

[152] NIPSCO Initial Brief at 21-22.

[153] Midwest TDUs note that Capacity Suppliers represent that they control 13,300 MW, or about 10 percent of the generation in MISO, which would be a substantial portion of the one-quarter of non-utility affiliated generation cited by Capacity Suppliers. Midwest TDUs reference information from NextEra establishing that almost all of

(continued...)

term contract with LSEs and therefore indistinguishable from utility generation. Midwest TDUs also note that much of the nameplate capacity of MISO's non-utility generation is wind-powered, for which long-term power purchase agreements are the norm. Finally, Midwest TDUs note that recent plant closures and sales have further reduced the amount of non-utility generation in MISO. Midwest TDUs conclude that, even assuming the accuracy of Capacity Suppliers' representation that one-quarter of the generation in MISO is non-utility owned, only a small fraction of MISO generation could be merchant facilities outside of Illinois that are not committed on a long-term basis.[154]

78. Several parties argue that LSEs in the MISO zone have no incentive to exercise buyer-side market power.[155] Parties explain that a price suppression strategy in the residual market makes no sense as a rationale for procuring "uneconomic" resources when the "in-auction" procurement is small, as the necessary circumstances to create such an incentive are absent in MISO.[156] Parties argue that LSEs have a legitimate business purpose in offering their capacity resources in the market at their incremental going forward cost, rather than at a net CONE level or anything close to a full cost-of-service rate, and assert that traditional state regulation, particularly with integrated

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NextEra's generation in MISO is sold under long-term contracts, and provide evidence that Calpine, Exelon, Ameren, and Dynegy also have significant resources in MISO under long-term contracts. In total, Midwest TDUs estimate that 5,548 MW of the Capacity Suppliers' MISO generating fleet is under long-term contract, wind generation for which a long-term contract is highly desirable, and/or was sold to a utility after the Capacity Suppliers filed their request for rehearing. Midwest TDUs Initial Brief at 15-20.

[154] *Id.* at 14-23

[155] *E.g.*, Organization of MISO States Initial Brief at 12-14; Indicated MISO Load Serving Entities Initial Brief at 10-14; APPA/NRECA Initial Brief at 12-14.

[156] *E.g.*, MidAmerican Initial Brief at 27-29. For example, the APPA/NRECA's witnesses explain that an exercise of buyer-side market power "can be profitable only for entities that are net purchasers of capacity, where the net purchases are large relative both to the buyer's needs and to the relevant total market . . . . Furthermore, any buyer who might consider investing in uneconomic capacity in an attempt to depress market-clearing prices must contemplate the substantial risks that other generation firms will react to uneconomic entry in ways that will make the price manipulation unsustainable for the many years of uneconomic capacity's lifetime. . . ." APPA/NRECA Initial Brief at 12-13 (quoting Kirsch/Morey Affidavit at 13-14 (citations omitted)); *see also* Midwest TDUs Initial Brief at 29 (citing and quoting Wilson Aff. ¶¶ 41-46, 53).

resource planning, leads regulated utilities *not* to be net short capacity.[157] For example, referencing the Commission's holding with respect to the ISO-NE capacity market, in which the Commission concluded that "a competitive offer for most existing resources would be expected to be quite low since the added costs for providing capacity in many cases is nearly zero,"[158] Midwest TDUs argue that new resources being offered into MISO's near-term capacity market are functionally "existing" resources, as the costs to construct them have already been sunk, and the costs that can be avoided if the capacity does not clear in the auction are near zero.

79. Accordingly, parties argue that it is fully rational to offer a new resource's capacity into the residual market at that capacity's going-forward, avoidable cost, which may well approach zero, and that the Commission has long recognized that sales at levels that recover avoidable costs, with some contribution to fixed costs, reflect "the normal competitive process at work."[159] Indeed, Coalition of MISO Customers argue that traditional utilities' profits will increase (all things else being equal) as the investment in new plant increases, so those utilities have an incentive to invest in new generation capacity to grow their earnings, regardless of what clearing prices may be in MISO's capacity market.[160] In addition, parties argue that the Commission has existing enforcement tools that could be used to address any manipulative conduct in the market.[161]

80. Numerous parties allege that the imposition of a MOPR, in the absence of buyer-side market power incentives, would irreparably harm MISO's established regulatory model and impair the region's ability to assure future resource adequacy.[162] Parties assert that imposing a MOPR in a traditionally-regulated region like MISO threatens to severely undermine long-term procurement decisions made by LSEs with state regulatory

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[157] *E.g.*, Midwest TDUs Initial Brief at 30-31; Organization of MISO States Initial Brief at 12; Duke Initial Brief at 11-12.

[158] Midwest TDUs Initial Brief at 31 (quoting *ISO New England, Inc. and New England Power Pool Participants Committee*, 138 FERC ¶ 61,027, at P 122 (2012)).

[159] *E.g.*, *id*. at 32-33 (quoting *Pub. Serv. Co. of Okla.*, 54 FERC ¶ 61,021, at 61,032 (1991)); *see also* Indicated MISO Load Serving Entities Initial Brief at 11-12.

[160] Coalition of MISO Customers Initial Brief at 5.

[161] *E.g.*, Organization of MISO States Initial Brief at 21-23.

[162] *E.g.*, NIPSCO Initial Brief at 20-21; APPA/NRECA Initial Brief at 24-26.

oversight through the retail ratemaking, siting, and integrated resource planning processes.[163] Parties argue that a MOPR could force LSEs to pay for capacity twice if a resource failed to clear the capacity market,[164] and are concerned that a MOPR would make traditional, long-term planning and procurement procedures highly risky, devastate state renewable programs (if applied beyond gas-fired units, as Capacity Suppliers request), and threaten the regulatory construct that gives LSEs in MISO an incentive to procure resources through cost-of-service recovery for prudent investment.[165] Midwest TDUs also note that MISO expressly intended that its "new one year voluntary resource adequacy mechanism will allow state regulators to meet policy goals in a way that ensures reliability and affordability," and that "MISO will continue to rely on state processes for resource planning," as its "new voluntary one-year capacity mechanism with self-schedule and opt-out provisions respects existing state regulatory processes."[166] Midwest TDUs further contend that it would be inconsistent with Commission policy to make it hazardous for LSEs in MISO to make long-term power supply commitments, and argue that section 217(b)(4) of the FPA commands the Commission to use its authority to support the planning and expansion of the transmission system and enable LSEs to secure transmission rights on a long-term basis for long-term power supply arrangements planned to meet LSE needs to meet their service obligations.[167]

81. Midwest TDUs and NIPSCO argue that even if there was a rational basis to impose a MOPR in MISO, the Commission should not do so at this time, as a MOPR would undermine LSE and state regulatory efforts to assure resource adequacy at a time when, according to MISO's projections, new resources will be needed as early as 2016, due to the retirements and retrofits resulting from EPA regulations.[168] To the extent additions are needed to replace retiring resources, Midwest TDUs state that there is every

[163] *E.g.*, Midwest TDUs Initial Brief at 37; Organization of MISO States Initial Brief at 15-17; APPA/NRECA Initial Brief at 28-29.

[164] *E.g.*, APPA/NRECA Initial Brief at 25.

[165] *E.g.*, Midwest TDUs Initial Brief at 38; NIPSCO Initial Brief at 39-42.

[166] Midwest TDUs Initial Brief at 38 (quoting MISO, *Resource Adequacy*, *available at* https://www.misoenergy.org/Library/Repository/Communication%20Material/One-Pagers/ResourceAdequacy.pdf).

[167] Midwest TDUs Initial Brief at 36-39; *see also* NIPSCO Initial Brief at 44.

[168] NIPSCO Initial Brief at 25.

reason to think that LSEs in MISO will do so under the traditional cost-of-service model; however, imposing a MOPR "would discourage LSEs from acting promptly to meet the resource adequacy challenge through the traditional planning processes, in the hope that MOPR-elevated spot capacity price might timely attract sufficient needed generation investment."[169] Midwest TDUs also provide evidence that several LSEs in MISO have already announced plans for new generation, but argue that there is no assurance that if efforts like these are discouraged by a MOPR, that the MISO capacity market would incent sufficient investment to meet forecasted load needs in 2016 or thereafter. Midwest TDUs also question whether non-utility generators would, in fact, jump at the chance to add resources to meet MISO's 2016 needs, as merchants with existing generation stand to benefit from scarcity.

82. Parties argue that a MOPR would not be pro-competitive and would be unsupported by relevant anti-trust law.[170] For example, Midwest TDUs characterize a MOPR as a "price floor," theoretically designed to ensure that prices are not suppressed below a competitive level, but question whether an administratively-determined price floor would be able to accurately determine that competitive level.[171] Parties note that the Commission's mission is to protect competition and consumers, not competitors,[172] and that price floors are disfavored, as "[l]ow prices benefit consumers regardless of how those prices are set" and buyers are entitled to set their own offers.[173] Midwest TDUs state that no party alleges that low offer prices in MISO's markets have been, or will be, the result of collusion, and argue that state-sponsored generation programs cannot be deemed collusion, as they seek to increase, rather than suppress, output. Midwest TDUs caution the Commission against inferring that simply because a price offered in the residual capacity market is low, it should be "mitigated" upwards as the result of an exercise of market power. Midwest TDUs note that Capacity Suppliers are not obligated to sell into MISO's near-term residual auction, as, among other options, they can sell earlier through long-term bilateral contracts, or sell to neighboring regions; given these fundamentals, Midwest TDUs argue that buyer-side market power cannot be inferred

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[169] Midwest TDUs Initial Brief at 40-43.

[170] *E.g.*, *id.* at 44; Organization of MISO States Initial Brief at 23-25.

[171] *E.g.*, Midwest TDUs Initial Brief at 43-45.

[172] *E.g.*, Organization of MISO States Initial Brief at 32-35.

[173] Midwest TDUs Initial Brief at 45 (quoting *Atlantic Richfield Co. v. USA Petroleum Co.*, 495 U.S. 328, 340 (1990)).

from the fact that in a given year's auction, some offers are low.[174] Midwest TDUs also challenge Capacity Suppliers' reliance on *Weyerhaeuser Co. v. Ross-Simmons Hardwood Lumber Co.*,[175] arguing that the case concerned over-bidding rather than under-bidding, and that, even under that precedent, capacity offers can be legitimately priced below net CONE.[176]

83. Finally, parties argue that the Commission's decision not to adopt a MOPR does not discriminate against merchant and retail choice providers as compared to utility-owned generation.[177] Responding to Capacity Suppliers' argument that MISO's Commission-approved mitigation rules fail to apply "equivalent" standards to buyer- and seller-side market power mitigation, Midwest TDUs argue that: (1) buyers and sellers are not similarly-situated, as LSEs are captive, with load-serving obligations, and must procure capacity, while merchant suppliers may decide what generation, if any, they wish to purchase, whether and where to build new generation, and where to market their capacity;[178] (2) it is entirely consistent with the FPA to be more assertive in preventing high prices than in preventing low ones, as guarding consumers – not guarding sellers from consumers – is a statutory objective;[179] (3) the Commission-approved rules make no distinctions that are adverse to merchant generators, as the obligation to offer energy from resources that elect to receive capacity credits applies to all generators;[180] (4) although Capacity Suppliers' argument equates "buyers" to LSEs and "sellers" to

[174] *Id.* at 43-50.

[175] 549 U.S. 312 (2007) (extending to the buyer market power context the U.S. Supreme Court's test for claims that a seller with market power has bid anticompetitively).

[176] Midwest TDUs Initial Brief at 50-57.

[177] *E.g.*, APPA/NRECA Initial Brief at 21-23.

[178] *See also* Indicated MISO Load Serving Entities Initial Brief at 17-18; APPA/NRECA Initial Brief at 22-23 (noting that the "absence of buyer-side market power mitigation mechanisms where there are seller-side mitigation mechanisms does not, in and of itself, indicate a problem").

[179] *See also* APPA/NRECA Initial Brief at 23.

[180] *See also* MidAmerican Initial Brief at 20 (noting that similarly-situated sellers are paid exactly the same amount under the MISO Tariff, regardless of their business model).

merchant generators, MOPRs do not restrict "bids" submitted by load, but rather the price of capacity resource offers, and as such they relate to market participants acting as sellers; (5) *Dynegy Midwest Generation, Inc. v. FERC*[181] did not concern market power mitigation, but rather whether each transmission pricing zone's transmission owner(s) should have the option to stop most cost-based reactive power payments to generators, an issue of zone-by-zone discretion that is not at issue here; (6) seller market power mitigation in MISO's market is more narrowly targeted than Capacity Suppliers' proposed MOPR, as the seller market power mitigation applies in limited circumstances, while the MOPR would apply regardless of any impact test; and (7) merchant generators, should they choose to do so, have opportunities to share the risk-reducing benefit of the MISO region's reliance on long-lived generation assets, financed by stable loads and long-term commitments.[182] Indicated Load-Serving Entities further argue that a MOPR is not needed to protect against undue discrimination between LSEs within MISO in states that have adopted retail choice and LSEs that continue to serve under traditional regulatory models, as MISO's Tariff does not treat generators or LSEs differently under its current rules.[183]

84. Should the Commission nonetheless require a MOPR, parties argue that the Commission should give MISO broad leeway to develop a MISO-specific approach, and should not require LSEs to purchase capacity that they do not need.[184] Parties also request that the Commission reject Capacity Suppliers' proposals to make MISO's MOPR more restrictive (e.g., 100 percent net CONE, applying the MOPR to all new resources) than in the eastern markets.[185]

c. Reply Briefs in Favor of MOPR

85. NRG and Capacity Suppliers disagree with assertions that a MOPR will cause inefficient outcomes. Specifically, NRG contends that the MOPR will benefit ratepayers

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[181] 633 F.3d 1122 (D.C. Cir. 2011).

[182] Midwest TDUs Initial Brief at 57-62; *see also* APPA/NRECA Initial Brief at 17-19 (arguing that the "missing money" problem for some generators is a consequence of their choosing to do business solely in MISO-run markets and ignore bilateral markets).

[183] Indicated MISO Load Serving Entities Initial Brief at 15-17.

[184] *E.g.*, MidAmerican Initial Brief at 30-32; Midwest TDUs Initial Brief at 63.

[185] *E.g.*, Midwest TDUs Initial Brief at 62-65; NIPSCO Initial Brief at 48-51.

by disciplining the desire for irrational investments in new resources. NRG contends that, contrary to the assertions of certain parties, in instances where no capacity is needed, but the LSE elects to build new capacity anyway to meet non-economic objectives and the resource fails to clear, capacity prices should be mitigated. NRG contends that the Commission should protect ratepayers from such premature or uneconomic investment.

86. NRG disagrees with the argument put forth by certain parties, including Midwest TDUs, that the Commission should not require a MOPR because LSEs would cease building resources because they would be at risk of purchasing the same resource twice.[186] NRG argues that such an argument ignores the "entire point of a capacity market" of influencing the behavior of market participants by providing them with transparent pricing information.[187] Building uneconomic generation, NRG reasons, would needlessly increase costs to ratepayers. Consequently, NRG reiterates its position that new resources should be unable to count resources that have not cleared in the auction towards their capacity requirements. Capacity Suppliers state that, contrary to the assertions of certain parties, a MOPR is not a barrier to new entry, only a barrier to uneconomic new entry.[188] NRG and Capacity Suppliers also respond to fears by parties that their resources would not clear, leading to double payment. NRG argues that the danger of trapped capacity that is procured as it is needed is exceedingly slim because a facility need only clear once in a capacity auction to be deemed existing capacity, and thus not subject to further price mitigation.[189] Capacity Suppliers argue that such a situation would be limited to uneconomic resources, which should not be allowed to suppress wholesale prices.[190]

87. NRG argues that there may need to be special accommodations for utilities that have already commenced construction prior to the Commission taking action in this proceeding.[191] NRG states that it would support an appropriate transition period to

[186] NRG Reply Brief at 2-4 (citing Midwest TDUs Initial Brief at 4).

[187] *Id.*

[188] Capacity Suppliers Reply Brief at 22 (citing NIPSCO Initial Brief at 26).

[189] NRG Reply Brief at 5 (citing MidAmerican Initial Brief at 12).

[190] Capacity Suppliers Reply Brief at 22 (citing Organization of MISO States Initial Brief at 9; Hoosier and Southern Illinois Initial Brief at 9; Conway Corporation Comments at 6-7).

[191] NRG Reply Brief at 6 (citing Louisiana Energy and Power Authority Comments at 7).

accommodate entities that have decided to build new resources prior to Entergy joining MISO or comparable situations.

88. NRG disagrees with parties who argue that LSEs should have the right to make economically inefficient investments because they make decisions on a multi-year time scale, and take a long-term view of their capacity needs.[192] NRG asserts that the MOPR in no way inhibits utilities from employing long-term planning to make economically efficient siting decisions. NRG explains that the MOPR allows an LSE concerned about a potential shortfall in resources to bid its new resources into the market and objectively test whether the new resource indeed represents the lowest cost increment of new capacity to meet its needs in the long run. NRG disagrees with the premise that an LSE would be harmed by delaying construction of a new resource until it is actually needed because there would be less expensive options available.[193]

89. NRG also responds to arguments that certain parties have a low cost of capital or other inherent advantage that allows them to build a new project at a cheaper cost.[194] NRG asserts that such arguments do not favor eliminating a MOPR but rather the use of competitive benchmarking following the adoption of the MOPR, which the Commission could direct MISO to address in a number of ways, as demonstrated by the Eastern RTOs.[195]

90. NRG and Capacity Suppliers disagree with arguments that a MOPR would create a price floor and fix prices at anti-competitive levels.[196] NRG argues that MOPRs only come into play when project sponsors attempt to bid capacity into the market at an artificially low price, rather than at the true cost. NRG explains that MOPR rules typically allow project sponsors to bid the lower of an administratively-determined threshold or the actual price. Consequently, there is no price floor. Capacity Suppliers also disagree with arguments that an effective MOPR would cause wholesale rates to rise

[192] *Id*. (citing Arkansas Electric Initial Brief at 15; APPA/NRECA Initial Brief at 14-16.)

[193] *Id*.

[194] *Id.* at 8 (citing Hoosier and Southern Illinois Initial Brief at 12).

[195] *Id*. at 7-8.

[196] *Id.* at 8 (citing Southwestern Initial Brief at 7; APPA/NRECA Initial Brief at 16); Capacity Suppliers Reply Brief at 22 (citing Organization of MISO States Initial Brief at 23; Midwest TDUs Initial Brief at 43).

to, and lock in at, the CONE.[197] However, they concede that under normal supply and demand conditions, capacity prices would be expected to equal the CONE.

91. NRG and Capacity Suppliers disagree with assertions that the preponderance of bilateral contracting in MISO is inconsistent with a MOPR.[198] NRG states that existing units are exempt from the MOPR, leaving only bilateral contracts for new resources subject to the MOPR. NRG contends that this structure leads to cost minimization. It also notes that sophisticated parties can structure bilateral contracts such that the construction and payment only begins if the project clears the auction. Capacity Suppliers contend that wholesale capacity prices drive bilateral market prices because rational buyers will not pay substantially more in the bilateral market than they can pay in the wholesale market. Capacity Suppliers state that buyers have not refuted the assertion that wholesale markets drive bilateral prices, creating an incentive to suppress prices in the wholesale market. Capacity Suppliers dismiss as unsupported claims that the longer terms of most bilateral contracts reduce this effect and argue that if buyers forecast wholesale prices at near zero, they will demand very low prices in the bilateral market.[199]

92. NRG and Capacity Suppliers also disagree with assertions that because generators in MISO are largely under long-term contracts, or because private entities are actively seeking out new contracting opportunities, the Commission has no need to ensure just and reasonable rates for merchant generation.[200] Such an argument, NRG asserts, ignores the more than 4,000 MW of uncontracted capacity that NRG owns in the new MISO South Zone. NRG further contends that this argument ignores the fact that bilateral contracting and a strong MOPR are not mutually exclusive – so long as the new resources are actually needed by the marketplace or the LSE wishes to make an uneconomic investment decision in support of some alternative goal.[201] Capacity Suppliers contend that capacity buyers in MISO have the incentive to suppress capacity prices, as admitted by certain buyers.[202] They point out that other parties deny such an incentive exists or

[197] Capacity Suppliers Reply Brief at 23 (citing Indicated MISO Load Serving Entities Initial Brief at 11).

[198] NRG Reply Brief at 9 (citing Southwestern Initial Brief at 7; Arkansas Electric Initial Brief at 15); Capacity Suppliers Reply Brief at 9-10.

[199] Capacity Suppliers Reply Brief at 9-10.

[200] NRG Reply Brief at 9-10; Capacity Suppliers Reply Brief at 5.

[201] NRG Reply Brief at 9-10.

[202] Capacity Suppliers Reply Brief at 5-6 (citing Hoosier and Southern Illinois

(continued...)

that there are even net buyers in MISO, but contend that such arguments are not credible because basic economics dictate that rational buyers prefer lower prices.[203] Further, such parties, according to Capacity Suppliers, fail to acknowledge that a well-functioning capacity market retains or attracts the least-cost, most reliable resources when and where needed. Capacity Suppliers contend that a utility-by-utility or state-by-state approach cannot achieve such benefits because their pools of resources are smaller.

93. Capacity Suppliers also disagree with arguments that price discrimination does not occur in the current wholesale market because similarly situated buyers are paid exactly the same amount under the Tariff.[204] Capacity Suppliers contend that such an assertion ignores out-of-market subsidies paid to new resources. Where such resources are uneconomic but clear in the market because of subsidies, they reduce the prices paid to existing resources. Capacity Suppliers contend that out-of-market payments result in market distortions because not all resources are paid the same price in the wholesale market.

94. Capacity Suppliers contend that certain parties have misinterpreted the result of the 2013-2014 Planning Year Capacity Auction, which resulted in an RTO-wide clearing price of $1.05 per MW-day. This amount translates into about $38.25 per MW-year, in contrast to the CONE, which ranges from $85,990 per MW-year to $91,610 per MW-year in MISO, according to Capacity Suppliers.[205] Capacity Suppliers insist that such prices reveal the flaws in the current market design, considering that MISO has forecasted capacity shortages as soon as 2016.[206] Such prices, according to Capacity Suppliers,

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Initial Brief at 10 ("[A] buyer always has an incentive to reduce the price of any goods or services it buys . . .")).

[203] *Id.* at 6 (citing NIPSCO Initial Brief at 23).

[204] *Id.* at 7-8 (citing MidAmerican Initial Brief at 20).

[205] *Id*. at 10 (citing Midcontinent Indep. Sys. Operator, Inc., Filing, Docket No. ER13-2310-000, at 8 (filed Sept. 3, 2013)).

[206] *Id.* (citing MISO Markets Committee of the Board of Directors, *Resource Adequacy Framework Presentation* 3 (Oct. 2013) (indicating that "[c]urrent forecasts project available resources to be below [P]lanning [R]eserve [M]argin requirements by 2016"), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/Markets%20Committee/2013/20131023/20131023%20Markets%20Committee%20of%20the%20BOD%20Item%2006%20Framework%20Resource%20Adequacy.pdf).

indicate that almost all existing generation should retire. Capacity Suppliers also assert that certain parties contradict themselves by simultaneously describing the need for new capacity while asserting that there is no evidence that the current capacity construct, combined with state planning processes, is insufficient to ensure reliability.[207]

95. Capacity Suppliers also disagree with arguments that LSEs have little incentive to suppress prices because the vast majority of offers were either self-scheduled or submitted as part of a fixed resource adequacy plan.[208] They believe that such lack of participation reflects that the flawed capacity market forces merchants into the suppressed bilateral market. Capacity Suppliers point out that the Commission has found that such opted-out resources, once "seasoned" by operating as part of a fixed resource adequacy plan in the first year, could be offered in the auction at a zero price the following year and be exempt from mitigation.[209]

96. Capacity Suppliers also contend that the relatively small amount of merchant generation in MISO does not, under the FPA, permit the Commission to allow undue discrimination against minority interests. Capacity Suppliers also take issue with arguments that so-called "gambling" generators who rely upon wholesale capacity market prices are not worthy of just and reasonable rates and may be discriminated against.[210] Capacity Suppliers contend that the Commission has never suggested that capacity markets should feature prices so low so as to be punitive in this manner. Capacity Suppliers also contend that prices in the wholesale market affect all existing generators and that a MOPR does not solely benefit participants in the wholesale market. Additionally, Capacity Suppliers argue that it is contradictory to argue that merchants are too small to require a MOPR but too large to avoid seller market power mitigation. Further, they disagree with assertions that the anti-manipulation rule alone is sufficient to deter the exercise of buyer-side market power. Capacity Suppliers contend that the more tailored approach of a MOPR is more effective than broad catch-all standards. Capacity Suppliers also disagree with arguments that asymmetric mitigation is permissible because generators can choose what market to participate in while LSEs are trapped. They contend that the capacity market is also "asymmetric" in that it is mandatory for sellers, but voluntary for buyers, and that generators can only sell in other markets under certain

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[207] *Id.* at 10-11.

[208] *Id.* at 12 (citing NIPSCO Initial Brief at 2).

[209] *Id*. (citing June 11 Order, 139 FERC ¶ 61,199 at P 68).

[210] *Id*. at 13-14 (citing Midwest TDUs Initial Brief at 4-5; APPA/NRECA Initial Brief at 18).

conditions.[211] They argue that neither side should be permitted to artificially influence prices.

97. Capacity Suppliers also contend that the FPA explicitly confers jurisdiction to the Commission over wholesale sales of electricity and transmission such that, pursuant to sections 205 and 206 of the FPA, the Commission is required to ensure that rates charged for jurisdictional transactions are just and reasonable.[212] Consequently, Capacity Suppliers contend that states cannot be allowed to determine the reasonableness of resource adequacy if such choices interfere with the Commission's determination of just and reasonable rates. In such cases, according to Capacity Suppliers, there is need for an independent market monitor or RTO to intrude on state decisional processes, contrary to the positions of certain buyers. Consequently, the Commission cannot permit states or other capacity buyers to suppress prices in the wholesale market. They further contend that it is instead the obvious side-effect of state-sponsored new entry that bids into the wholesale market are below costs. Capacity Suppliers assert that the elimination of merchant generation cannot be the by-product of traditional regulation, be it accidental or intentional. Capacity Suppliers also assert that, even with a MOPR, which only prevents discrimination in the wholesale market, states remain free to make decisions affecting generation, including siting and policies in favor of certain resources.

98. Capacity Suppliers also argue that Congress and the Commission have already decided that they prefer competition and markets over traditional regulation.[213] According to Capacity Suppliers, the Commission has found that PJM needs to protect against both buyer-side and seller-side market power. They argue that competition is more efficient, because factors other than efficiency, including utility desire to grow their rate bases, often drive traditional regulation. They also argue that uneconomic entry begets more required subsidized new entry to replace retiring resources that do not receive subsidies and that an effective MOPR would support the Commission's policy

[211] *Id.* at 15-17.

[212] *Id*. at 18 (citing *New York v. FERC*, 535 U.S. 1, 16-17 (2002); 16 U.S.C. §§ 824(b), 824d, 824e).

[213] *Id*. (citing *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001)).

objectives and statutory obligations in this regard by eliminating artificially suppressed prices and improving market signals.[214]

99. Capacity Suppliers reiterate their contention that the MISO proposal must be revised to effectively mitigate buyer-side market power, including to address manipulation enabled by the fixed resource adequacy plan. Contrary to the assertions of certain parties, the Commission cannot abrogate its statutory duty based on stakeholder preferences with respect to the MOPR, as advocated by certain parties.[215] Capacity Suppliers also note that although certain parties characterized Capacity Suppliers' preference for the MOPR to mitigate to 100 percent of net CONE as having been rejected by the Commission, the Commission has recently approved such mitigation in PJM.[216]

d. **Reply Briefs Opposing MOPR**

100. Several parties reiterate their opposition to the MOPR, both as proposed by MISO and as proposed to be revised by the Market Monitor, Capacity Suppliers, and NRG.[217]

101. Several commenters allege that the Market Monitor, by questioning the necessity of a MOPR depending on the purpose of the MISO capacity market, effectively concedes that a MOPR is not necessary in MISO.[218] For example, Midwest TDUs argue that the MISO capacity market serves only as a spot capacity balancing market, and that resource owners receive long-term price signals from bilateral markets and ownership reviews.[219] Similarly, MidAmerican argues that the Market Monitor misstates the purpose of the capacity market as providing "a mechanism for ensuring long-term resource adequacy in the MISO footprint." MidAmerican asserts that LSEs and their regulators, not MISO, are responsible for assuring resource adequacy in the MISO region, and that the MISO

[214] *Id.* at 23-24.

[215] *Id.* at 25-26 (citing Organization of MISO States Initial Brief at 20).

[216] *Id*. at 26 (citing *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,090, at PP 195-98 (2013)).

[217] For example, NIPSCO notes that nearly every party that submitted an Initial Brief supported the Commission's decision to reject the MOPR. NIPSCO Reply Brief at 2-3.

[218] *E.g.*, Midwest TDUs Reply Brief at 3-6; NIPSCO Reply Brief at 6-8.

[219] Midwest TDUs Reply Brief at 4.

resource adequacy construct, which is an incremental tool for acquiring short-term capacity, can assist in that effort, but cannot supplant or conflict with it.[220] The Organization of MISO States further alleges that the Market Monitor's question misses the point of the proceeding, as the question at issue is whether the Commission should impose a MOPR in pursuit of a goal to cause the price signal produced by the MISO capacity auction to become the predominant (or only) influence on investment, retirement, and maintenance decisions in MISO.[221] In addition, commenters argue that MOPR supporters provide no evidence that the MISO region's existing resource adequacy paradigm will incent the region's LSEs and states to exercise the buyer-side market power that the MOPR supposedly mitigates.[222] Duke, citing examples from Eastern RTOs, further argues that, because of the open and transparent nature of state regulatory action, even if a state did intend to exercise buyer-side market power through its LSEs, the Commission will have sufficient forewarning to prevent any actual attempt at price suppression.[223]

102. Commenters argue that MOPR supporters have failed to demonstrate that a MOPR is appropriate for the MISO region.[224] For example, MidAmerican alleges that NRG and Capacity Suppliers describe the necessity of a MOPR in a market that is very different than the MISO market. MidAmerican emphasizes that the MISO capacity construct is characterized by a preponderance of long-term bilateral contracting, a one-year auction occurring only two months in advance of the Planning Year, and an auction created for incremental capacity purposes.[225] MidAmerican also asserts that NRG promotes a wholesale market design that stands at odds with the typical state-regulated resource planning function that exists in most of the MISO region, and notes the opposition to a MOPR from both the Organization of MISO States and the Joint Consumer Advocates (i.e., the two groups with significant statutory obligations for regulating and advocating on behalf of consumers).[226] MidAmerican further argues that Capacity Suppliers'

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[220] MidAmerican Reply Brief at 7-8.

[221] Organization of MISO States Reply Brief at 3.

[222] Midwest TDUs Reply Brief at 11; Duke Reply Brief at 7-11.

[223] Duke Reply Brief at 4-7.

[224] *E.g.*, Midwest TDUs Reply Brief at 7-12.

[225] MidAmerican Reply Brief at 11.

[226] *Id.* at 14. The Joint Consumer Advocates are the Indiana Office of Utility Consumer Counselor, the Iowa Office of Consumer Advocate, the Minnesota Department

(continued...)

proposed revisions to the MOPR conflict with state regulation and arbitrarily eliminate self-supply unless regulators are held hostage to a "truly nondiscriminatory auction process."[227] Numerous parties allege that MOPR supporters have also failed to demonstrate that the existing MISO resource adequacy construct will be unable to address anticipated capacity shortages in coming years.[228]

103. Parties also argue that bilateral markets are unlikely to take their price signals from the MISO capacity auction, given the short-term nature of the purchase and the long-term nature of the bilateral market.[229] Numerous parties reiterate that there is no incentive to exercise buyer-side market power in the MISO market. NIPSCO further alleges that Capacity Suppliers incorrectly argue that neither the amount of bilateral contracting nor the amount or generation divestiture in the MISO footprint should have any bearing on whether a MOPR is instituted; to the contrary, they allege that adoption of a MOPR would inject unwarranted uncertainty into the traditional state-driven procurement process in MISO.[230] Other parties similarly argue that theoretical claims that a MOPR can accommodate self-supply or state integrated resource planning processes are unsupported.[231] Other commenters argue that MOPR supporters failed to substantiate their assertions about the amount of merchant generation in the MISO footprint.[232]

104. Several parties argue that certain MOPR supporters' initial briefs address issues that are beyond the scope of the Commission's briefing order, and ask the Commission to

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of Commerce, the Missouri Office of the Public Counsel, the Montana Consumer Counsel, and the Citizens Utility Board of Wisconsin. The Joint Consumer Advocates filed a motion to intervene and protest to MISO's July 2011 filing in which MISO proposed the MOPR. *See also*, *e.g.*, American Municipal and the Michigan South Central Power Agency Reply Brief at 5-7.

[227] MidAmerican Reply Brief at 16.

[228] *E.g.*, APPA/NRECA Reply Brief at 5-7.

[229] *E.g.*, MidAmerican Reply Brief at 17.

[230] NIPSCO Reply Brief at 11-13.

[231] *E.g.*, APPA/NRECA Reply Brief at 9-11.

[232] NIPSCO Reply Brief at 10-11.

adopt proposed revisions to the MOPR that are beyond what MISO proposed and the Commission rejected.[233]

4. Commission Determination

105. We deny rehearing of the decision to reject MISO's proposed MOPR. In brief and as noted above, in the June 11 Order, the Commission concluded that buyers lacked the incentive to suppress auction prices in the MISO capacity market. The Commission's reasoning was that most capacity in MISO is owned by traditionally-regulated utilities that would not need to purchase a significant amount of capacity through the auction, and thus, would not benefit significantly from lower auction prices. On rehearing, some parties argued that the Commission's rationale was flawed, because about one-fourth of capacity in MISO is not owned by traditionally-regulated utilities. After receiving further information, we continue to conclude that a MOPR is not needed at this time for the MISO capacity market. While some capacity in MISO is owned by merchants rather than traditionally-regulated utilities, the record before us indicates that most merchant capacity has been sold under long-term contracts. The purchasers of this capacity would not benefit significantly from suppressing prices in the MISO capacity market, because the purchasers do not purchase a significant amount of capacity through the auction, and thus, would not benefit significantly from lower auction prices. In its briefs, Midwest TDUs present data demonstrating that most merchant generators, including those owned by Capacity Suppliers, are under long-term contracts, a fact which is not disputed. LSEs in MISO that own or have long-term contractual rights to capacity for most or all of their capacity requirements are unlikely to be able to recoup the expense of subsidizing new resources through reduced prices in the organized capacity market, because such LSEs buy little or no capacity in the organized capacity market.

106. Capacity Suppliers do not dispute Midwest TDUs' conclusion that most merchant generators are under long-term contracts. In response, Capacity Suppliers argue that the extent of long-term contracting is irrelevant, because buyers always prefer lower prices. We agree that buyers prefer lower prices. However, Capacity Suppliers' argument ignores the fact that loads do not pay current capacity market prices for capacity that they have acquired in the past under long-term contracts, but rather a price agreed upon in the past. Subsidizing uneconomic entry that suppresses current capacity market prices would not suppress prices that have previously been locked in by long-term contract. Because, based on the record before us, the vast majority of capacity in MISO has been acquired by LSEs either through ownership or through long-term contracts, the potential benefits

[233] *E.g.*, Coalition of MISO Customers Reply Brief at 2-4; Midwest TDUs Reply Brief at 13; NIPSCO Reply Brief at 8; American Municipal and the Michigan South Central Power Agency Reply Brief at 3.

of, and thus incentive to engage in, price suppression are greatly diminished, which indicates that a MOPR is unnecessary.

107. NRG contends that the June 11 Order did not address the interplay between the bilateral market and the Commission's centralized resource adequacy construct. Similarly, Capacity Suppliers argue that a MOPR is necessary because prices in the capacity market heavily influence bilateral contract prices. We agree that the spot capacity market is an alternative to the bilateral market, so contracting parties are likely to consider expected future spot market prices when determining the prices they are willing to accept in bilateral contracts. But several factors mute the effect of spot market prices on bilateral prices. First, any price effects on long-term bilateral contracts would occur only slowly over time as contracts expire and new contracts are negotiated. Second, the MISO capacity auction involves one year of capacity auctioned two months before the start of the Planning Year, while bilateral capacity purchases generally are for longer terms. So, to the extent contracting parties consider spot market prices in negotiating long-term bilateral contracts, they are likely to consider expected spot market prices over time – not spot market prices in any single year.

108. As recognized by some of the parties, bilateral contracts negotiated in any one year are unlikely to reflect the prices in the MISO capacity auction in any one year. A substantial amount of uneconomic capacity over many years would be needed in order to have a significant effect on bilateral contract prices, and those price effects would not be felt on contracts that have not yet expired. The costs of such uneconomic entry would be substantial and any resulting reductions in bills due to lower bilateral contract prices would need to be discounted because they would occur in the future. NRG and Capacity Suppliers have provided no evidence that buyers in MISO or their agents could profitably engage in uneconomic investment in order to suppress prices. We also disagree with Capacity Suppliers that the amount of bilateral contracting is irrelevant. To the extent that the overall amount of bilateral contracting is relatively small (with most resources owned by the LSEs) the amount of resources whose prices would be influenced each year by changes in the auction prices diminishes, rendering profitable price suppression through uneconomic entry harder still.

109. We also disagree with the assertion that low auction participation rates indicate that prices are not just and reasonable. Certain LSEs may prefer the cost certainty of using their own resources or relying on long-term contracts. Further, contrary to NRG's and Capacity Suppliers' claims that buyer-side market power needs to be mitigated, there is no evidence in the record of any exercise of buyer-side market power in MISO auctions or bilateral prices.

110. Additionally, low prices, in and of themselves, do not demonstrate that a market is not just and reasonable. For instance, such prices are justified in instances where a region contains substantial excess capacity unrelated to intentional uneconomic entry. Similarly, we disagree with NRG's argument that the current MISO capacity market structure lacks

a robust and transparent means of incenting merchant generators to remain viable. Such resources could sell capacity as part of long-term bilateral contracts, locking in a level of capacity revenues based on their expected value over the life of the agreements or could sell their capacity in the auction each year. In neither case must rates, in order to be just and reasonable, assure viability of such resources, so long as the prices in the market reflect supply and demand conditions. Depending on these conditions, merchant generators, particularly those that elect to sell into the auction, could be considerably more or less profitable than resources whose costs are recovered through cost of service rates.

111. NRG points to the Commission's recognition of the importance of buyer-side mitigation in ISO-NE and PJM and disagrees with the contention that buyer-side mitigation rules are appropriate for Eastern RTOs but not for MISO. However, as noted in the June 11 Order and by several parties, unlike Eastern RTOs, the MISO region is largely comprised of traditional obligation-to-serve utilities without restructured retail markets. This composition enables LSEs and regulators in the region to undertake longer-term commitments to generation resources, either in the form of direct construction by incumbent LSEs or through comparable long-term contracts.

112. Capacity Suppliers also disagree with arguments that, because similarly situated buyers are paid exactly the same amount under the Tariff, price discrimination does not occur in the current wholesale market.[234] Capacity Suppliers contend that out-of-market subsidies result in market distortions because not all resources are paid the same price in the wholesale market. We do not find this argument persuasive in this context because, in MISO, the lower auction price that may result from this strategy would provide little benefit because auction volumes are so small. While such a strategy may be theoretically possible, it would require the new resource to offer all or most of its capacity in the auction and the LSE buyer to buy a significant amount in the auction in order to be of benefit. There is no evidence in the record of such market behavior by LSE buyers. Such a strategy of out of market payments would not impact the cost of other supplies that are also owned or under long-term contract. Also, differences between the price in the MISO capacity market in any given year and prices in bilateral contracts do not necessarily reflect undue discrimination, in part because the term lengths are different. The MISO capacity market commits the resource for one year, and the prices in the MISO auction thereby reflect market conditions during that year. By contrast, bilateral contracts in MISO are often for much longer than one year, and the prices in these contracts reflect expected market conditions over these longer periods.

[234] Capacity Suppliers Reply Brief at 7-8 (citing MidAmerican Initial Brief at 20).

113. We also disagree with Capacity Suppliers' argument that the absence of a MOPR unduly discriminates against the minority of parties that rely on the capacity market. As discussed above, we find no evidence in the record of price suppression in the auction or of the ability of LSEs to profit from a price suppression strategy.

114. Capacity Suppliers also argue that the Commission must prevent undue discrimination against merchant generators that arises because the capacity market is mandatory for sellers, but voluntary for buyers. We find that there need not be symmetry between mitigation for buyers and sellers because of differences in how they could exercise market power. As discussed above in this section, based on the record before us, LSEs do not appear to have the incentive to exercise buyer-side market power, and thus, buyer-side market power mitigation through mandatory participation in an auction with a MOPR is not necessary. By contrast, exercising seller market power requires no multi-year time horizon or upfront investment, only the withholding of existing resources, rendering it easier to execute.

115. Capacity Suppliers also claim that it is the obvious side-effect of state-sponsored new entry that bids into the wholesale market are made below costs. However, they fail to provide evidence of their claim and therefore do not demonstrate that a MOPR is necessary at this time. Additionally, Capacity Suppliers argue that sections 205 and 206 of the FPA require the Commission to assert jurisdiction over wholesale sales of electricity, such that the Commission cannot abdicate such a role to the states for MISO's capacity market. We disagree with the contention that a continued planning role for states is mutually exclusive with the Commission assuring just and reasonable prices for the capacity market. We are not allowing states to determine the reasonableness of resource adequacy, as Capacity Suppliers argue. LSEs must still satisfy their capacity obligations, as determined by MISO's FERC-jurisdictional tariff.

116. As the Commission previously found with respect to the MISO resource adequacy requirement,[235] we generally accept the role for state regulatory authorities in resource adequacy requirements set forth in MISO's proposal. However, the role for state authorities cannot undercut this Commission's authority to review resource adequacy and reserve margins that affect matters within our jurisdiction, i.e., provisions that affect our authority under sections 201, 205, and 206 of the FPA to ensure that the provisions of the tariff will result in just and reasonable and not unduly discriminatory or preferential rates. The Commission has in other instances also addressed its jurisdiction over resource adequacy requirements.[236]

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[235] March 2008 Order, 122 FERC ¶ 61,283 at P 52.

[236] *See ISO New England Inc.*, 119 FERC ¶ 61,161, at PP 27-29 (2007); *Cal.*

(continued...)

117. Capacity Suppliers also argue that Congress and the Commission have already decided that they prefer competition and markets over traditional regulation and that an effective MOPR would support the Commission's policy objectives and statutory obligations in this regard by eliminating artificially suppressed prices and improving market signals. We agree with Capacity Suppliers with regard to the value of competition, but find that Capacity Suppliers have not demonstrated that a MOPR is needed in MISO to protect competition. Further, although the Commission has supported market-based capacity constructs, it has given regions substantial discretion to design their resource adequacy constructs based on their conditions and stakeholder preferences. While Capacity Suppliers cite Order No. 2000 to support their statement that the Congress and the Commission have expressed a preference for competition over traditional regulation, we note that Order No. 2000 did not endorse specific capacity market constructs.

118. Because, as described above, we find that it has not been demonstrated that a MOPR is needed in MISO, we need not address arguments on how elements of the MISO resource adequacy requirement, including the partial opt-out through the fixed resource adequacy plan, allow circumvention of a potential MOPR. For the same reason, we will not address arguments regarding how to improve the proposed MOPR to make it more effective.

119. Further, arguments that recent developments in MISO, including the entry of Entergy into MISO's footprint, demonstrate the need for a more robust capacity construct with a MOPR are speculative. In particular, NRG has not demonstrated that Entergy has exercised buyer-side market power or could do so profitably within the MISO resource adequacy construct. Further, we find that Indicated Capacity Suppliers have not demonstrated a causal link between the results of the MISO OMS Survey and the lack of a MOPR in MISO.

120. Also speculative are Capacity Suppliers' claims that MISO's current capacity construct without a MOPR will lead to market price distortions and suppressed market-wide clearing prices. Although NRG argues that ratepayers of integrated utilities are in no way disadvantaged by a competitive capacity procurement mechanism that includes buyer-side market power mitigation rules and that establishing a MOPR-type mechanism is consistent with allowing states with integrated resource planning programs to plan their systems, for the reasons discussed above, we do not find that a MOPR is necessary to

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Indep. Sys. Operator Corp., 119 FERC ¶ 61,076, at PP 540-564 (2007); *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, at PP 1112-1120 (2007) (citing *Cal. Indep. Sys. Operator Corp.*, 115 FERC ¶ 61,172, at P 36 (2006); *Gainesville Utils. Dep't. v. Florida Power Corp.*, 402 U.S. 515, 529 (1971)).

ensure just and reasonable rates in the MISO region, as we have in other regions.[237] For the reasons discussed above, we deny rehearing on these issues. We also do not address explanations of how a theoretical MOPR would work,[238] since they are beyond the scope of this proceeding.

C. Fixed Resource Adequacy Plan

1. June 11 Order

121. In its July 2011 filing, MISO proposed that LSEs can "opt out" of the auction by submitting a fixed resource adequacy plan demonstrating that they have sufficient resources to cover all or a portion of their resource requirements. The Commission accepted MISO's proposed opt-out provisions, observing that the proposal would enable LSEs to manage how they fulfill their capacity requirements. Additionally, the Commission noted that MISO's opt-out provisions would ensure that MISO's resource adequacy construct would retain the voluntary nature of Module E.[239]

2. Requests for Rehearing

122. Capacity Suppliers and Demand Response Supporters both argue that the fixed resource adequacy plan is inconsistent with precedent.[240] According to Demand Response Supporters, the Commission has observed that the goal of eliciting a reliable,

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[237] With respect to various points raised by parties regarding the features of a competitive and functional capacity market, and comparisons between the MISO resource adequacy construct and resource adequacy constructs in other RTOs, we consider these arguments to be generally applicable to the MISO resource adequacy construct rather than the reasonableness of the MOPR. Accordingly, we do not address these issues here but instead address them elsewhere in this order.

[238] *See* NRG Reply Brief at 5.

[239] June 11 Order, 139 FERC ¶ 61,199 at PP 19, 41.

[240] Capacity Suppliers Request for Rehearing at 18 (citing *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145 at P 175 ("PJM . . .explains that, due to the nature of [PJM's Reliability Pricing Model] and the [Fixed Resource Requirements] option, [LSEs] should not be able to serve their load partially through [PJM's Reliability Pricing Model] and partially through the [Fixed Resource Requirements] option. PJM argues that such an allowance could give rise to gaming opportunities.")); Demand Response Supporters Request for Rehearing at 4.

long-term supply of capacity would not be compromised by an opt-out mechanism so long as the LSE commits to procure a specified amount of capacity for an extended period of time.[241] Demand Response Supporters also assert that the Commission's approval of the fixed resource adequacy plan contradicts the Energy Policy Act of 2005 and contradicts the Commission's prior statements by creating a barrier to participation by demand response resources.[242]

123. Capacity Suppliers also state that the Commission's approval of the fixed resource adequacy plan erroneously relies on regional differences. Capacity Suppliers argue that any regional differences that may exist do not justify the Commission's "approval of an opt-out mechanism that …can easily suppress prices."[243] Specifically, Capacity Suppliers contend that, regardless of whether entities purchase the majority of their capacity bilaterally or through an auction, suppressed prices at auction will affect all capacity prices and allow buyers to "price squeeze competitors out of the market."[244]

124. Capacity Suppliers contend that the Commission failed to consider evidence in the record. Specifically, Capacity Suppliers assert that evidence in the record supports the notion that there is no need for an opt-out mechanism.[245] However, Capacity Suppliers state that the affidavit of Dr. Shanker describes "key details of any workable opt-out," which should include: (1) designation of specific generation in the opt-out at least as far in advance as the rest of the market; (2) opt-out resources must meet locational requirements for the LSE; (3) recognition that LSEs that opt-out may be carrying lower levels of reserves and thus have lower levels of reliability than in-market resources; and (4) a deficiency charge above the CONE.[246]

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[241] Demand Response Supporters Request for Rehearing at 4 (citing *PJM Interconnection, L.L.C.,* 115 FERC ¶ 61,079, at P 102 (2006)).

[242] *Id.*

[243] Capacity Suppliers Request for Rehearing at 19.

[244] *Id*

[245] *Id.* at 20 (citing Capacity Suppliers Motion to Intervene and Protest, Shanker Aff. at 25).

[246] *Id.* (citing Capacity Suppliers Motion to Intervene and Protest, Shanker Aff. at 31-33).

125. Capacity Suppliers and Demand Response Supporters both urge the Commission to reverse its approval of MISO's fixed resource adequacy plan provisions. Capacity Supplies argue that the fixed resource adequacy plan would allow load to game the capacity market. According to Capacity Suppliers, the June 11 Order recognizes as much in its discussion of the MOPR.[247] Demand Response Supporters state that permitting LSEs to partially opt-out of the capacity auction in one year, and participate in the next, will create pricing distortions. As an example, Demand Response Supporters note that LSEs may choose to self-supply high cost resources while offering low cost resources in the auction. Such distortions, in turn, impair the ability of other participants to evaluate and participate in the market. Demand Response Supporters note that this impairment is particularly important to demand response resources that must register prior to the LSE opt-out deadline.[248]

126. Alternatively, if the Commission does not grant rehearing of its determination with respect to the opt-out, Capacity Suppliers argue that the opt-out mechanism must be changed to "an all-in or all-out mechanism with a minimum duration requirement."[249] Moreover, Capacity Suppliers state that any opt-out must include the aforementioned features described by Dr. Shanker.

3. <u>Commission Determination</u>

127. We deny requests for rehearing with respect to the fixed resource adequacy plan. The Commission's discussion in the June 11 Order of potential gaming behavior that results from the fixed resource adequacy plan was a hypothetical example only. The Commission found in the June 11 Order, cited by Capacity Suppliers, that LSEs do not have an incentive to exercise market power in the MISO region. Therefore, in this context in which the Commission determined that the possibility for market manipulation was unlikely, our acceptance of the fixed resource adequacy plan option is reasonable. We are not persuaded by Capacity Suppliers' and Demand Response Supporters' assertions and hypothetical examples that LSEs could game capacity by "price squeezing" behavior to push competitors out of MISO's market. Specifically, we have no evidence in the record of the "price squeezing" behavior that Capacity Suppliers

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[247] Capacity Suppliers Request for Rehearing at 17-18 (citing June 11 Order, 139 FERC ¶ 61,199 at P 68) ("If an LSE wanted to suppress the price in the capacity auction through uneconomic entry, it could do so by any of the [fixed resource adequacy plan] opt-out provisions.").

[248] Demand Response Supporters Request for Rehearing at 5.

[249] Capacity Suppliers Request for Rehearing at 20.

reference, nor do we see evidence of competitors being pushed out of the market and a resultant decrease in reserve margins due to "price squeezing". Furthermore, as discussed in section VI.B.4, Capacity Suppliers and Demand Response Supporters have not demonstrated how LSEs could recoup the expense of subsidizing new resources through reduced capacity prices and thereby exercise market power in the manner discussed in their hypothetical examples.[250]

128. For the same reasons, we see no need to revise the fixed resource adequacy plan so that it is an all-in or all-out mechanism with a minimum duration requirement or other various restrictions on fixed resource adequacy plan participation. LSEs have little to be gained by attempting to suppress prices in the MISO auction,[251] and therefore there is no basis for Capacity Suppliers' and Demand Response Supporters' assumption that LSEs would shift their designations and purchases of capacity resources between the fixed resource adequacy plan and the auction and between zones in order to exercise market power. With respect to the other elements of Capacity Suppliers' proposed workable opt-out, Capacity Suppliers have not demonstrated that such provisions are necessary. Given MISO's vertical demand curve, LSEs cannot manipulate the result of the auction through either opting in and out between years or partially opting out in a given year. Every MW that an LSE includes in a fixed resource adequacy plan correspondingly reduces the amount of MW that must be procured from the auction. Assuming the opted out MWs would be self-scheduled, which logic dictates would be the case to keep the LSE indifferent to market results, the supply and demand curves shift in tandem as a result of opting out, leaving the auction clearing price unchanged.

129. Our task in this proceeding is to evaluate whether MISO's proposal is just and reasonable. Accordingly, our determination must be based on the record in this proceeding. It is not our task here to determine if other RTOs have identical options, as Capacity Suppliers contend, and for this reason we deny the request for rehearing on this basis. We do not agree with Capacity Suppliers' conclusion that the record of this proceeding shows that there is no need for a fixed resource adequacy plan mechanism. The evidence cited by Capacity Suppliers - a statement in the affidavit of their witness Dr. Shanker that opt-out mechanisms are not desirable because of their impact on price signals – has no bearing on the necessity for a fixed resource adequacy plan mechanism.

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[250] *See supra* section VI.B.4.

[251] *See supra* section VI.B.4.

D. Annual Planning Resource Auction and Forward Period

1. June 11 Order

130. In the June 11 Order, the Commission accepted MISO's proposed one-year auction term and two-month forward period.[252] The Commission explained that MISO's proposal reasonably tied the one-year auction term to MISO's Planning Year. Moreover, the Commission found that MISO's proposal reasonably requires resources participating in the auction to be committed two months before the Planning Year. The Commission also rejected alternative frameworks proposed by protestors, observing that it need not choose the most reasonable alternative amongst a series of proposals.[253]

2. Requests for Rehearing

131. Ameren and Capacity Suppliers contend that the Commission erred in approving MISO's proposed two-month forward period and should require MISO to adopt a longer-term forward period. Ameren argues that the Commission's failure to respond to arguments raised by Ameren and others that the two-month forward commitment period would result in poor price signals and an ineffective market renders the Commission's findings arbitrary, capricious, and inconsistent with reasoned decision-making.[254] Similarly, Capacity Suppliers contend that the June 11 Order offers "scant support" for the Commission's approval of the two-month forward period and the Commission's statement that the proposal is reasonable is insufficient to rebut the record evidence to the contrary.[255] For instance, Ameren argues that the Commission failed to respond to Ameren's claims that the two-month forward period proposed by MISO would provide market participants with insufficient time to respond to the auction's price signals.[256] Ameren and Capacity Suppliers argue that, due to this shortcoming, the auction will not effectively encourage long-term capital investment. Ameren further states that the Commission failed to respond to its assertions that failure to adopt a forward period that

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[252] June 11 Order, 139 FERC ¶ 61,199 at P 187.

[253] *Id.* (citing *ISO New England, Inc.*, 138 FERC ¶ 61,042, at P 84 n.97 (2012); *ISO New England, Inc.*, 138 FERC ¶ 61,027 at P 75 n.109; *Oxy USA, Inc. v. FERC*, 64 F.3d at 692).

[254] Ameren Request for Rehearing at 8-14.

[255] Capacity Suppliers Request for Rehearing at 23.

[256] Ameren Request for Rehearing at 8-9.

would send the proper price signals could impair reliability. Capacity Suppliers assert that new resources "will have to look elsewhere, and one of the fundamental purposes of a capacity market construct—attracting economic new entry at the time and place in which it is needed—will be lost."[257] Capacity Suppliers also argue that the affidavit of Dr. Shanker demonstrates that a two-month forward period fails to provide the forward price signal needed by existing merchant resources to consider making capital intensive upgrades.[258] Capacity Suppliers suggest that record evidence demonstrates that a two-month forward period will prevent transmission solutions from competing in the capacity auctions on equal footing with generation and demand response. In addition, Capacity Suppliers argue that Dr. Shanker's affidavit shows that a two-month forward period will result in an extremely volatile market with "no merchant entry into the market."[259] Further, Capacity Suppliers highlight evidence suggesting that such volatility "makes it difficult to address fast-moving market changes—such as coal retirements caused by new environmental regulations."[260]

132. Ameren and Capacity Suppliers also contend that the Commission neglected to respond to protestors' assertions that MISO's proposed resource adequacy construct would be inconsistent with MISO's earlier recognition that a longer forward period was necessary to give LSEs time to plan to upgrade or retire facilities, and that the pending integration of the Entergy companies necessitated a longer and more rational planning period.[261]

133. Ameren also argues that the Commission's findings are contrary to its prior determination that a three-year forward commitment is necessary for adequate consideration of both generation and transmission options for achieving resource adequacy.[262] Ameren states that the Commission has "specifically found '[t]he purpose of holding [PJM's Reliability Pricing Model] three years in advance of the Delivery Year

[257] Capacity Suppliers Request for Rehearing at 23 (citing *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,318, at P 92 (2007)).

[258] *Id.* at 24.

[259] *Id.* at 25.

[260] *Id.* at 27-29.

[261] Ameren Request for Rehearing at 9 (citing Capacity Suppliers Protest at 23; NRG Protest at 10); Capacity Suppliers Request for Rehearing at 29-30.

[262] Ameren Request for Rehearing at 11.

is to ensure that both new generation and transmission can be considered in determining reliability.'"[263] Ameren argues that under a two-month commitment period, a resource that has not yet been built cannot participate in time to be available for the Planning Year. As a result, Ameren concludes that the Commission has failed to explain this departure from precedent.

134. Ameren further argues that the Commission failed to engage in reasoned decision-making by basing its findings on the presumption that most LSEs will continue to obtain most or all of their capacity resources outside of the auction.[264] Ameren states that such a finding ignores the fact that "[t]he MISO region is not static and may become less vertically-integrated [sic] over time."[265] Ameren also asserts that the Commission's finding with respect to the two-month forward period ignores the fact that changes in environmental regulations require a longer forward commitment period in order to get generation built and ensure resource adequacy.[266]

135. Additionally, Ameren argues that the June 11 Order is internally inconsistent.[267] Ameren states that on the one hand, the Commission recognized that capacity portability is a key issue that needs to be addressed. However, on the other hand, Ameren states that the Commission's failure to require a three- to five-year forward commitment period will maintain a seam between MISO and PJM. Ameren states that the maintenance of such a seam is contrary to the Commission's policy in favor of interregional coordination and could interfere with the development of system enhancements to improve resource adequacy.[268]

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[263] *Id.* (quoting *PJM Interconnection, L.L.C.*, 128 FERC ¶ 61,157, at P 125 (2009)).

[264] *Id*. at 12.

[265] *Id*.

[266] *Id.* at 13.

[267] *Id.* at 14.

[268] *Id.* (citing *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323, at PP 368-70 (2011), *order on reh'g and clarification*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014)).

136. If the Commission does not grant Ameren's request for rehearing, Ameren states that the Commission should direct MISO to evaluate the effectiveness of its capacity markets once they have commenced and to determine whether the use of a three-to-five-year forward period would be more effective.[269] Ameren suggests that such a requirement would be consistent with the Commission's recognition of the need to address capacity portability and seams between MISO and other regions.[270]

137. Ameren also requests that the Commission clarify that the deficiency charge required by the Commission in the June 11 Order should take into account any additional costs the market participant faces to bring resources to market due to the abbreviated two-month forward period.[271]

3. Commission Determination

138. We deny rehearing. We disagree with Ameren's and Capacity Suppliers' claims that the two-month forward period proposed by MISO is not just and reasonable because it would provide insufficient time to respond to the auction's price signals and thus fail to encourage sufficient long-term investment to ensure reliability. While a forward auction can be helpful in encouraging long-term investment, especially in restructured markets, there is nothing in the record to demonstrate that an auction with a long forward period is necessary to encourage long-term investment in markets such as in MISO, where traditionally-regulated utilities predominate. In MISO, most generation is either under long-term contract or owned by utilities regulated under cost-of-service regulation. Either of these models provides long-term revenue assurances of cost recovery to new resources. Revenue from the capacity market is not necessary in MISO to finance needed new generation, and thus, ensuring reliability does not require an auction with a long forward period. The flaw in Ameren's and Capacity Suppliers' argument is the assumption that market participants wait for the two-month forward period to make their supply arrangements. In fact, most market participants in MISO are making long-term supply arrangements continually as they negotiate bilateral arrangements and develop owned-resources. By the time the two-month forward period commences, many LSEs have already made their plans and decided their strategy for obtaining capacity. Accordingly, the only new meaningful activity occurring during the two-month forward period is wrapping up any final sales and purchases prior to the auction.

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[269] *Id.* at 14-15.

[270] *Id.* at 15.

[271] *Id.* at 15-16.

139. Inasmuch as the two-month forward period does not play a significant role in resource planning in MISO, we do not see a basis for assuming that a longer forward period is needed to encourage long-term capacity investment. Nor do we consider the two-month forward period to be unreasonable because planned resources cannot compete against existing resources in the auction. Planned resources and existing resources are competing in the negotiation process for long-term bilateral arrangements and development plans of LSEs. The competition for residual capacity not already committed to long-term arrangements is not significant, and therefore not a basis for faulting the lack of competition in the MISO resource adequacy construct. In this framework, we dispute Capacity Suppliers' contention that the forward period requires new resources to look elsewhere in order to sell their capacity.

140. Ameren states that the Commission failed to respond to its assertions that failure to adopt a forward period would not send the proper price signals and could impair reliability. In the June 11 Order, the Commission disagreed that the proposed annual auction term will harm long-term reliability. The Commission stated that under MISO's resource plan framework, most LSEs will continue to obtain most of their supplies outside the auction and we have no basis for assuming that a longer auction term is needed to ensure resource sufficiency.[272] We affirm that finding, as discussed in the previous paragraph. In any case, Ameren's claims are speculative, as Ameren has provided no compelling evidence that failure to provide a longer forward period will harm reliability.

141. Although Ameren and Capacity Suppliers argue that the Commission neglected to respond to protestors' assertions that MISO's proposed resource adequacy construct would be inconsistent with MISO's earlier recognition that a longer forward period was necessary, as noted in the June 11 Order, MISO's planning period was the outcome of MISO's stakeholder process.[273] Differences between what MISO proposed in the stakeholder process, to that ultimately proposed to the Commission, represents a compromise among MISO stakeholders. While MISO and some stakeholders may have favored longer-term frameworks, when faced with competing proposals, the Commission may approve a proposal as just and reasonable.[274]

142. Ameren also points to a PJM capacity market order to argue that the Commission's findings are contrary to its prior determination that a three-year forward

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[272] *See* June 11 Order, 139 FERC ¶ 61,199 at P 187.

[273] *Id.* P 182.

[274] *Id.* n.300.

commitment is necessary for adequate consideration of both generation and transmission options for achieving resource adequacy. However, as the Commission stated in its order on PJM's proposed capacity market mechanism, "there is not a single just and reasonable method for satisfying capacity obligations."[275] In a market, such as PJM, where the vast majority of generation resources are not owned by utilities, a longer forward period may be appropriate to ensure the consideration of both generation and transmission solutions for maintaining reliability. However, in MISO, the overwhelming majority of load is served by vertically integrated utilities who, through integrated resource planning, consider both transmission upgrades and building or acquiring generation capacity to maintain reliability. Additionally, Ameren has not substantiated its contention that the closure of generation resources in MISO due to environmental regulations will render insufficient the existing processes for maintaining reliability.

143. With respect to Ameren's argument that the June 11 Order is internally inconsistent because the Commission recognized that capacity portability needs to be addressed, but that the Commission's determination will maintain a seam between MISO and PJM, we disagree. The two-month forward commitment period is an aspect of MISO's resource adequacy proposal. As the Commission noted in the order, capacity issues that are not part of MISO's proposed resource adequacy requirement revisions to the Tariff are beyond the scope of this proceeding. Further, Ameren has not demonstrated that capacity portability problems between MISO and PJM due to inefficiencies in the seam between them substantively stems from differences in forward periods.

144. We decline to grant Ameren's request to direct MISO to evaluate the effectiveness of its capacity markets once they have commenced. Although we recognize the need to address capacity portability and seams between MISO and other regions, these issues are under discussion elsewhere.[276] Additionally, we decline to grant Ameren's request to modify the deficiency charge to take into account any additional costs the market participant faces to bring resources to market due to the abbreviated two-month forward period. The design of the deficiency charge is addressed in the compliance proceeding in Docket No. ER11-4081-002[277]

145. We also disagree with Capacity Suppliers' assertion that a two-month forward period would prevent transmission solutions from competing on even footing with

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[275] *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 at P 103.

[276] *See, e.g.*, Docket Nos. AD12-16-000 and AD14-3-000.

[277] *Midwest Indep. Transmission Sys. Operator, Inc.*, 153 FERC ¶ 61,230.

generation and demand response resources. Most capacity in MISO is obtained via long-term bilateral arrangements. Among other processes, it is during the negotiations and planning for these long-term commitments, that various resource and transmission options are considered – not during a two-month forward period. We also disagree with Capacity Suppliers' contention that a two-month forward period would result in high volatility and "no merchant entry into the market."[278] As described above, the entry of merchant generators into a market is reflected in the negotiation of long-term bilateral arrangements. Despite Capacity Suppliers' assertions, MISO has featured ongoing merchant entry and the development of utility-owned resources.[279] The flaw in Capacity Suppliers' argument is the premise that the annual capacity auction is the primary mechanism for LSEs to adjust their resource planning for significant changes. Based on the history of resource planning in MISO, this assumption is incorrect. Further, high volatility does not necessarily render a market unjust and unreasonable if such volatility accurately reflects underlying supply and demand conditions.

146. We consider Capacity Suppliers' argument that MISO's forward period and vertical demand curve prevent new resources from fully competing in the auction[280] to be an argument that the forward period alone is the cause of this result. Capacity Suppliers' discussion – i.e., new resources take longer than two months to plan and build – applies only to the two-month forward period. Our discussion earlier in this section addresses this concern.

E. Vertical Demand Curve

1. June 11 Order

147. In the June 11 Order, the Commission accepted MISO's proposal to establish a fixed reliability target expressed as a single MW value, otherwise known as a vertical demand curve.[281] The Commission explained that it has historically allowed RTOs substantial latitude in determining their reliability requirements. Additionally the Commission explained that there is not a single just and reasonable method of satisfying capacity obligations and, in fact, the Commission has approved the use of both downward

[278] Capacity Suppliers Request for Rehearing at 23.

[279] *See supra* section VI.B.3.b (Midwest TDUs recitation of new resource development).

[280] Capacity Suppliers Request for Rehearing at 23.

[281] *See* June 11 Order, 139 FERC ¶ 61,199 at PP 238, 245.

sloping and vertical demand curves in different regions.[282] The Commission noted that MISO proposed to retain its fixed reliability target for resource planning and its methodology for determining the planning resource requirement contained in its existing resource adequacy construct. Consequently, the Commission accepted MISO's proposal because it was consistent with MISO's previously approved tariff provisions.

2. Requests for Rehearing

148. The Market Monitor, Capacity Suppliers, and NRG argue that the Commission erred in approving this component of MISO's proposal and in rejecting an administrative, sloped demand curve. While conceding that the Commission has previously approved a vertical demand curve in MISO, the Market Monitor argues that this fact does not suggest that it is reasonable to carry this framework forward under the new resource adequacy construct.[283] The Market Monitor asserts that the performance of the existing resource adequacy construct has not been demonstrated to have produced reasonable market outcomes.[284] According to the Market Monitor, capacity prices in MISO have consistently remained close to zero, even in months with very little surplus capacity.[285] The Market Monitor states that this problem would be exacerbated in the construct approved by the Commission.

149. The Market Monitor explains that the clearing prices in MISO's existing capacity auctions are attributable to the presence of a vertical demand curve, which is inconsistent with the underlying reliability value provided by capacity.[286] According to the Market Monitor, a vertical demand curve implies that the last MW of capacity needed to satisfy the reserve requirement has a value equal to the deficiency price and the first MW of surplus has a value of zero. The Market Monitor explains that this interpretation is incorrect because in reality, each unit of surplus will improve reliability and lower costs for consumers.

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[282] *Id.* P 245 (citing *N.Y. Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201, *reh'g denied*, 105 FERC ¶ 61,108 (2003)).

[283] Market Monitor Request for Rehearing at 4-5.

[284] *Id.* at 5.

[285] *Id.*

[286] *Id.* at 6-7.

150. The Market Monitor additionally argues that the presence of a vertical demand curve is significant despite the fact that very little capacity clears through MISO's auction because the auction price provides a transparent spot price that should influence bilateral prices.[287] Further, the Market Monitor states that the performance of MISO's capacity auction will become increasingly significant over the next few years as environmental regulations are likely to cause a large quantity of coal resources to become uneconomic and result in a significant amount of retirements.

151. The Market Monitor contends that the approved market structure would be particularly devastating for investment in demand response resources. The Market Monitor states that without efficient market signals in the capacity market, demand response resources will not have efficient incentives to develop new resources.[288]

152. The Market Monitor also claims that the record contains no evidence that contradicts its findings or otherwise suggests that the vertical demand curve proposed by MISO will produce just and reasonable clearing prices.[289] In particular, absent sloped demand curves, the Market Monitor states that locational capacity prices will not distinguish the zones where capacity margins are falling and capacity shortages may be expected in the short-term.[290] Similarly, Capacity Suppliers assert that the June 11 Order failed to respond to record evidence concerning the volatility and flawed price signals created by a vertical demand curve. Capacity Suppliers assert that the Commission did not meaningfully respond to recommendations from the Market Monitor and others in favor of a sloped demand curve.[291] Capacity Suppliers contend that a sloped demand curve is essential to reduce the price volatility that will be caused by MISO's two-month forward period.[292]

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[287] *Id.* at 7.

[288] *Id.* at 8.

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

[290] *Id*. at 5.

[291] Capacity Suppliers Request for Rehearing at 29.

[292] *Id.* at 25. Capacity Suppliers point out that a sloped demand curve is coupled with a short forward period in the markets administered by New York Independent System Operator, Inc. in order to reduce volatility. *Id.* at 26.

153. NRG and the Market Monitor argue that the Commission's decision to accept MISO's proposed vertical demand curve deviates from the Commission's precedent. Specifically, the Market Monitor points out that the adverse effects of a vertical demand curve are mitigated in ISO-NE by a series of price floors that effectively establish horizontal demand curves.[293] Similarly, NRG argues that the presence of features such as the de-list process, a mandatory auction, and buyer-side mitigation in ISO-NE are designed to ameliorate the adverse impacts of a vertical demand curve, all of which are absent in the MISO's construct.[294] NRG further states that the Commission has previously recognized the benefits of sloped demand curves.[295] In particular, NRG contends that sloped demand curves: (1) provide a better estimate of the true value of capacity; (2) allow capacity procured above the installed reserve margin to have value; and (3) reduce the incentives for net buyers of capacity to bring new capacity resources into the market or strategically selecting a portion of load to remove from the auction via the opt-out mechanism. NRG asserts that the June 11 Order ignores these benefits in approving a construct that will "exacerbate the inability of the market to provide capacity prices above the current near-zero prices."[296]

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

154. We deny the requests for rehearing of the Market Monitor, NRG, and Capacity Suppliers with respect to the Commission's acceptance of MISO's use of a vertical demand curve.

155. We disagree with the Market Monitor's claim that the MISO resource adequacy plan is producing unreasonable market outcomes that can be attributed to the vertical demand curve. Based on the supply and demand conditions in the 2013/2014 Planning Resource Auction, whose results are part of the record in this proceeding, we do not consider the clearing prices in this auction to be unreasonable, nor do we consider the results of this auction to be an indication that the auction clearing prices are not providing accurate information on the value of reliability. The record in this proceeding provides no evidence of insufficient resource development where it is needed to ensure reliability. We do not dispute the Market Monitor's position that a sloped demand curve can provide

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[293] Market Monitor Request for Rehearing at 4.

[294] NRG Request for Rehearing at 12.

[295] *Id.* at 11 (citing *PJM Interconnection L.L.C.*, 119 FERC ¶ 61,318 at PP 76, 94, 99).

[296] *Id.* at 11-12.

additional information on the value of capacity or NRG's position that sloped demand curves can provide benefits. However, we find that an administratively-determined sloped demand curve would inappropriately diminish the deference given to states in the MISO capacity construct, which the Commission has previously recognized.[297] Even if states in MISO have not yet exercised their right to do so, the MISO resource adequacy construct allows them to determine the demand curve based on their own reserve requirements. An administratively-determined demand curve would inhibit states from doing so. Additionally, we have found that the vertical demand curve is a reasonable method for ensuring that LSEs procure sufficient capacity and our task here is not to choose among several reasonable alternatives.[298]

156. In response to Capacity Suppliers' argument that the June 11 Order did not address the Market Monitor's comments on the MISO resource adequacy proposal, we disagree.[299] The one issue not explicitly addressed in the June 11 Order was the Market Monitor's concern that a vertical demand curve provides an incentive for withholding of capacity.[300] We do not consider this concern to be a basis for rejecting MISO's proposal as unreasonable. As the Market Monitor admits, a sloped demand curve does not eliminate the potential for the exercise of market power, and therefore mitigation measures are necessary for both vertical and sloped demand curves.

157. As discussed in section VI.D.3, the possibility that capacity prices may be more volatile is not a basis to reject MISO's proposal as unreasonable. In the event that capacity prices are volatile in MISO, they are capped at CONE, a price the Commission has determined to be reasonable.

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[297] *Consumers Energy Co.*, 150 FERC ¶ 61,125, at P 78 (2014).

[298] *See ISO New England, Inc.*, 138 FERC ¶ 61,042 at P 84 n. 97 ("Faced with competing proposals, the Commission may approve a proposal as just and reasonable; it need not be the only reasonable proposal or even the most accurate."); *ISO New England, Inc.*, 138 FERC ¶ 61,027 at P 75 n.109; *Oxy USA, Inc. v. FERC*, 64 F.3d at 692 (finding that under the FPA, as long as the Commission finds a methodology to be just and reasonable, that methodology "need not be the only reasonable methodology, or even the most accurate one.").

[299] June 11 Order, 130 FERC ¶ 61,199 at PP 239, 245.

[300] Market Monitor Comments, Docket No. ER11-4081-000, at 9 (filed Sept. 16, 2011).

158. We disagree with the claim by Capacity Suppliers that a sloped demand curve is essential to ensure just and reasonable compensation and to provide incentives for new entry. As discussed above, the record shows that LSEs in MISO rely heavily on long-term power purchase agreements and owned resources for their capacity needs. The price of capacity under these long-term arrangements is not based on the auction price, and therefore the slope of the demand curve for auction prices is not essential to ensure just and reasonable compensation, nor would a sloped demand curve provide an incentive for new entry for generation with long-term bilateral contracts.

159. With respect to NRG's claim that the Commission has recognized that vertical demand curves reduce the incentive for net buyers of capacity to bring new resources into the auction, thereby reducing prices to zero, or strategically selecting a portion of load to remove from the auction via the opt-out, again forcing prices to zero the Commission has provided substantial flexibility to regions in determining their capacity construct demand curves. The Commission's support of a sloped demand curve in PJM does not therefore *de facto* require a sloped demand curve in MISO.

160. We disagree with the Market Monitor's contention that the vertical demand curve is not reasonable in a locational capacity market.[301] The vertical demand curves in each of the Local Resource Zones provide price signals that indicate the supply-demand balance in each zone, taking into account deliverability constraints. Accordingly, the vertical demand curve does not hinder the efficient operation of locational price signals.

161. We dispute the characterization of the Market Monitor and NRG that the June 11 Order relied solely on previous approvals of vertical demand curves for ISO-NE to justify a vertical demand curve in MISO. The primary point made in the June 11 Order was that there is not a single just and reasonable method for satisfying capacity obligations. We affirm this finding and we have found no basis in the pleadings made by parties to conclude that sloped demand curves are the only reasonable option.

F. Locational Market Mechanisms

1. Local Resource Zones

a. June 11 Order

162. In the June 11 Order, the Commission accepted MISO's proposal to establish zones based on the best available deliverability analysis and evaluation of, among other things, the electrical boundaries of local balancing authorities, state boundaries, the

[301] Market Monitor Request for Rehearing at 5.

relative strength of transmission interconnections between local balancing authorities, the result of loss of load expectation studies, the relative size of the Local Resource Zones, and natural geographic boundaries.[302] However, because the location of the zonal boundaries will significantly impact jurisdictional rates and the costs LSEs will incur in order to achieve resource adequacy, the Commission required MISO to incorporate a map of the zonal boundaries into the Tariff. The Commission also required that, as part of that filing, MISO provide a justification for the proposed zonal boundaries and explain any analysis it relied upon as a basis for its proposal.[303]

b. Requests for Rehearing

163. Ameren generally supports the Commission's decision to approve MISO's proposal to establish Local Resource Zones subject to the requirement that MISO file the initial boundaries as well as future modifications of those boundaries with the Commission.[304] Ameren requests that the Commission direct MISO to take additional steps in order to ensure that market participants have adequate time to respond to changes in the zonal boundaries in light of the two-month forward period. Ameren asserts that MISO should develop a minimum notice period before any changes to the zonal boundaries are implemented. For instance, Ameren proffers that MISO could be prohibited from proposing boundary adjustments that would take effect less than one year before the annual auction for the applicable Planning Year. Ameren contends that if the Commission or MISO adopts a longer forward period, the notice period should be no less than the length of the forward period adopted.[305] Additionally, Ameren proposes that MISO develop a minimum period in which the zonal boundaries will remain in effect. Ameren asserts that such a procedure would "help planning and provide financial certainty to market participants and other stakeholders."[306]

164. Midwest TDUs argue that "[i]f and to the extent that" the Commission accepted MISO's proposals to establish capacity zones based primarily on the electrical boundaries of local balancing authority areas, the Commission erred in failing to address the undue

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[302] June 11 Order, 139 FERC ¶ 61,199 at P 84.

[303] *Id.* P 86.

[304] Ameren Request for Rehearing at 19.

[305] *Id.* at 19-20.

[306] *Id.* at 20.

discrimination that would result.[307] Midwest TDUs state that, under MISO's proposal, the "first line-drawing parameter" is the electrical boundaries of local balancing authorities. In turn, Midwest TDUs state that the local balancing authority boundaries are based on the pre-MISO boundaries between transmission ownership areas.[308] According to Midwest TDUs, those boundaries were designed to encompass the generation plant sites of major vertically-integrated transmission owners, and not transmission-dependent utilities. Thus, Midwest TDUs argue that transmission owners' loads and long-term capacity resources are contained primarily within their local balancing authorities, and by extension, their Local Resource Zones. Midwest TDUs state that, in comparison, transmission dependent utilities typically straddle one or more zonal boundaries.[309] Consequently, transmission dependent utilities would be more likely to become subject to Zonal Deliverability Charges than major transmission owners.[310] Midwest TDUs state that the Commission has recognized that "transmission pricing designed to charge more for crossing legacy transmission ownership boundaries is unduly discriminatory, and that the market distortion introduced by this discrimination weakens regional markets."[311]

c. Commission Determination

165. We deny rehearing. Requiring MISO to adhere to a minimum notice period for zone changes longer than that required under the FPA is not necessary to ensure that the rates paid by LSEs for capacity are just and reasonable. Section 205 mandates that public utilities file proposed tariff revisions at least 60 days before such revisions are to take effect.[312] Although Ameren is correct in observing that MISO's designation and modification of zonal boundaries will affect the rates that LSEs pay, Ameren has failed to

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[307] Midwest TDUs Request for Rehearing at 10, 42-44, 58. Notably, Midwest TDUs claim that MISO's proposal will have a discriminatory effect both against LSEs' "capacity resources post-dating the July 2011 Grandmother cut-off," *see id.* at 58, as well as LSEs' capacity resources that would otherwise qualify for treatment as Grandmother Agreements. *Id.* at 42-44.

[308] *Id.* at 42.

[309] *Id.*

[310] *Id.* at 43.

[311] *Id.* (citing *Alliance Cos.*, 89 FERC ¶ 61,298, at 61,928 (1999), *order on reh'g*, 91 FERC ¶ 61,152 (2000), *reh'g denied*, 94 FERC ¶ 61,070 (2001)).

[312] 16 U.S.C. § 824d(d) (2012).

explain why more notice is required to ensure just and reasonable rates. Based on the residual role played by the voluntary auction, as discussed,[313] we do not find it necessary to require a minimum notice period tied to the auction's forward period. Further, Ameren's suggested one-year notice period would itself conflict with the Commission's regulations, which require that tariff revisions be filed no more than 120 days before they are to become effective.[314]

166. Such an additional notice period is also unnecessary because all future modifications to the zonal boundaries will be subject to the Commission's approval. In the June 11 Order, the Commission explained that the specification of zonal boundaries will significantly impact jurisdictional rates.[315] As a result, MISO is statutorily required to file all future modifications with the Commission, at which time interested parties will have the opportunity to intervene and submit comments supporting or opposing MISO's proposal.

167. Moreover, a notice period equal to the minimum notice required by the FPA is reasonable under the circumstances. As witness Moeller points out in his testimony, MISO anticipates that the zonal boundaries will largely remain static over time.[316] Thus, market participants will not be subject to constantly shifting boundaries. However, when circumstances require that zonal boundaries be modified to ensure reliability, limiting the notice period for effecting such changes could be advantageous. Specifically, MISO's proposal enables MISO to retain the flexibility to seek regulatory approval of the necessary modifications to file zonal modifications as necessary.

168. Ameren's proposal to establish a minimum period during which the zonal boundaries would remain in effect would fundamentally conflict with the statutory framework of the FPA. Under section 205, transmission providers such as MISO have discretion to determine not only what to propose in its filing, but also when to submit such a filing.[317] By effectively prohibiting MISO from proposing modifications to the

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[313] *See infra* section VI.A.

[314] 18 C.F.R. § 35.3 (2015).

[315] June 11 Order, 139 FERC ¶ 61,199 at P 86.

[316] MISO Filing, Docket No. ER11-4081-000, at Moeller Aff. ¶ 23 (filed July 20, 2011).

[317] *See Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252, at P 117 (2010) (citing *W. Mass. Elec. Co.*, 23 FERC ¶ 61,025 (1983), *aff'd sub nom. Commonwealth of Mass. v. FERC*, 729 F.2d 886 (1st Cir. 1984) (indicating that under section 205, public utilities

(continued...)

Tariff for a specified period of time, Ameren's proposal would infringe upon MISO's statutory prerogative under the FPA. Therefore, we deny Ameren's requests for clarification.

169. We disagree with Midwest TDUs that MISO's proposal to establish Local Resource Zones will unduly discriminate against transmission dependent utilities. In its July 2011 filing, MISO proposed to consider six factors in developing the boundaries of its Local Resource Zones. One of those six factors is the electrical boundaries of local balancing authorities.[318] The Commission accepted this proposal in the June 11 Order and expressly declined to require MISO to specify the weight it would assign to each factor.[319] With respect to Midwest TDUs' argument that the location of MISO's zonal boundaries will more often expose transmission dependent utilities to the Zonal Deliverability Charge, Midwest TDUs erroneously assume that the zonal boundaries will be solely or primarily based on the electrical boundaries of local balancing authorities. Accordingly, we affirm that the factors considered in the specification of zonal boundaries in MISO's proposal are just and reasonable and are not unduly discriminatory.

170. Furthermore, we note that the location of the zonal boundaries themselves were not at issue in the June 11 Order. Rather, the Commission accepted the factors that MISO proposed to consider in formulating the zonal boundaries. Therefore, it is premature to take issue with the effect of the zonal boundaries on transmission dependent utilities' exposure to the Zonal Deliverability Charge. In the event that Midwest TDUs come to believe that the zonal boundaries implemented by MISO unduly discriminate against transmission dependent utilities, those issues are properly addressed in the compliance proceeding in Docket No. ER11-4081-002 and in the proceedings addressing future zonal boundary revisions.

2. <u>Zonal Deliverability Charge and Grandmother Agreements</u>

a. <u>June 11 Order</u>

171. In the June 11 Order, the Commission conditionally accepted MISO's proposal to conduct auctions in each Local Resource Zone to ensure that LSEs purchase their

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have the discretion to choose whether or not to file)).

[318] June 11 Order, 139 FERC ¶ 61,199 at P 84; MISO Filing, Docket No. ER11-4081-000, at 8 (filed July 20, 2011).

[319] June 11 Order, 139 FERC ¶ 61,199 at P 84.

resources at prices that reflect the locational price differences embodied in the auction clearing price of the zone in which the load is located. Under MISO's proposal, all planning resources that clear in the auction receive the auction clearing price for the Local Resource Zone during the applicable forward Planning Year on a daily basis. MISO explains that LSEs with load in higher cost zones will pay a higher price than they are receiving for their resources in the lower cost zones. MISO refers to this difference as a Zonal Deliverability Charge since it reflects locational price differences. In its acceptance, the Commission noted that the Zonal Deliverability Charge recognizes transmission constraints in resource planning and will help to ensure reliability.[320]

172. The Commission determined that section 217 of the FPA does not bar implementation of the Zonal Deliverability Charge since the Zonal Deliverability Charge does not implicate the operation of transmission service under Module B of the Tariff or preclude LSEs from obtaining long-term firm transmission rights under FPA section 217.[321] The Commission also rejected protestors' arguments that Zonal Deliverability Charges violate Order No. 681.[322] The Commission found that Order No. 681 is not germane to MISO's proposal in general or to the Zonal Deliverability Charge in particular.

173. The Commission found that MISO's proposed Grandmother Agreement provisions, which would exempt LSEs from paying the Zonal Deliverability Charge if they possess firm transmission service from their resources to their load, were not compliant with the Commission's prior directives to establish locational market mechanisms in its resource adequacy construct.[323] The Commission stated that MISO's proposal would have the effect of exempting from the Zonal Deliverability Charge all LSEs' resources with long-term firm transmission agreements. The Commission therefore concluded that MISO's proposal would render the other components of its locational market mechanism meaningless. Nevertheless, the Commission recognized that LSEs in the MISO region that have historically relied on remote generation may benefit from a period of time to adjust their resource portfolios and to plan for additional

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[320] *Id.* P 101 (citing Locational Requirements Order, 126 FERC ¶ 61,144 at P 47; Locational Requirements Compliance Order, 131 FERC ¶ 61,228 at P 23).

[321] *Id.* P 104 (citing 16 U.S.C. § 824q (2012)).

[322] *Id.* P 106 (citing *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, FERC Stats. & Regs. ¶ 31,226, at P 24, *reh'g denied*, Order No. 681-A, 117 FERC ¶ 61,201 (2006)).

[323] *Id.* P 113.

resources in light of the impending effect of the Zonal Deliverability Charge.[324] Consequently, the Commission accepted MISO's proposed Grandmother Agreements subject to the condition they will only be effective during a two-year transition period, concluding at the end of the 2014/2015 Planning Year.

174. The Commission further subjected its acceptance of MISO's proposal to two additional compliance requirements.[325] First, the Commission stated that intrazonal capacity transactions that become interzonal transactions as a result of MISO's modifying the zonal boundaries should qualify as Grandmother Agreements. Further, the Commission explained that a combination of contracts that together provide for the delivery of capacity throughout the Planning Year meets the same purpose as a single contract that remains effective for the Planning Year. Consequently, the Commission directed MISO to file tariff revisions that would allow two or more contracts, which would in the aggregate otherwise satisfy the criteria for Grandmother Agreements, to be exempt from the Zonal Deliverability Charge during the two-year transition period.

b. Requests for Rehearing

i. Grandmother Agreements

175. Several parties contend that the Commission failed to adequately consider the penal effect of the Zonal Deliverability Charge on LSEs that procure capacity from inter-zonal resources.[326] For instance, Midwest TDUs assert that price signals are most appropriately sent before LSEs commit to capacity resources and that application of the unhedged Zonal Deliverability Charge to resources that would otherwise be treated as Grandmother Agreements would be unreasonable because LSEs have already procured their inter-zonal resources.[327] Among others, Wisconsin PSC suggests that LSEs cannot alter those contractual obligations.[328] In this respect, Midwest TDUs add that the

[324] *Id.*

[325] *Id.* PP 114-115.

[326] *See, e.g.*, Great River Energy Request for Rehearing at 4-5; Dairyland Request for Rehearing at 5; Midwest TDUs Request for Rehearing at 39-41; Wisconsin PSC Request for Rehearing at 7.

[327] Midwest TDUs Request for Rehearing at 39-41; *cf.* Wisconsin PSC Request for Rehearing at 5, 14-15.

[328] Wisconsin PSC Request for Rehearing at 15; *cf.* Great River Energy Request for Rehearing at 6-8.

Commission's holding would fail to honor LSEs' investment-backed capacity acquisitions that pre-dated MISO's proposal.[329]

176. Similarly, Ameren argues that the June 11 Order fails to address Ameren's assertion that Grandmother Agreements are necessary to protect market participants from being harmed unfairly.[330] Ameren states that the Commission also ignored the fact that in states where an LSE's resource was constructed pursuant to state integrated resource planning, the costs of that resource would be included in the LSE's retail rate base.[331] Consequently, retail customers could be forced to pay for the cost of the resource as well as any applicable Zonal Deliverability Charge. Furthermore, Ameren states that "generation facilities that are owned, constructed or acquired by an LSE pursuant to a state-mandated or state-approved [integrated resource plan] and reflected in an LSE's retail rate base should remain exempt from the Zonal [Deliverability] Charge if construction of the facility commenced prior to the submission of the [July 2011 filing]."[332]

177. Several parties also argue that the Commission erred in finding that approval of MISO's proposed Grandmother Agreements would allow LSEs to avoid using deliverability as part of their resource planning analyses and therefore negate the purpose and reliability benefits of the proposed locational market mechanism.[333] Midwest TDUs and Wisconsin PSC both contend that LSEs' reliance on network transmission service does not allow LSEs to ignore deliverability.[334] Rather, Midwest TDUs explain that LSEs have taken deliverability into account in procuring capacity resources because deliverability affects the cost of transmission service that an LSE must acquire to deliver capacity from a resource to load.[335] Wisconsin PSC suggests that application of the

[329] Midwest TDUs Request for Rehearing at 46-48.

[330] Ameren Request for Rehearing at 17.

[331] *Id.*

[332] *Id.* at 18.

[333] *See, e.g.*, Midwest TDUs Request for Rehearing at 39-46; Wisconsin PSC Request for Rehearing at 5, 14-15; Great River Energy Request for Rehearing at 4-11; Dairyland Request for Rehearing at 3-5; Ameren Request for Rehearing at 17.

[334] Midwest TDUs Request for Rehearing at 41; Wisconsin PSC Request for Rehearing at 24-27.

[335] Midwest TDUs Request for Rehearing at 41.

unhedged Zonal Deliverability Charge to preexisting capacity transactions is unnecessary because firm transmission service guarantees the deliverability of inter-zonal resources.[336] Dairyland adds that LSEs have already accounted for deliverability resources by funding transmission upgrades.[337] Midwest TDUs additionally challenge the benefits provided by an unhedged Zonal Deliverability Charge.[338] For example, Midwest TDUs suggest that the Zonal Deliverability Charge cannot influence procurement decisions to which MISO's proposed Grandmother Agreements would apply because those decisions have already been made and cannot be revised.[339]

178. Additionally, Midwest TDUs assert that Order Nos. 888,[340] 890,[341] 2000,[342] and their progeny fundamentally require MISO to provide long-term, firm delivery of customers' long-term-firm capacity resources.[343] Midwest TDUs contend that, pursuant

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[336] Wisconsin PSC Request for Rehearing at 24-27. Wisconsin PSC notably suggests that because firm transmission service is sufficient to ensure deliverability, the Commission further erred in failing to require MISO to provide a hedge for all capacity resources, including those resources acquired or developed after July 20, 2011, that would otherwise qualify for Grandmother Agreement status under MISO's proposal. *Id.*

[337] Dairyland Request for Rehearing at 5.

[338] Midwest TDUs Request for Rehearing at 44-46.

[339] *Id.* at 44-45.

[340] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[341] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[342] Order No. 2000, FERC Stats. & Regs. ¶ 31,089.

[343] Midwest TDUs Request for Rehearing at 21-24.

to these authorities, the Commission has already established a contingency for addressing binding transmission constraints. Namely, Midwest TDUs state that "MISO . . . has had since its founding, and should retain, a fundamental open-access obligation to . . . . plan and build the MISO Transmission System so as to maintain the long-term deliverability of resources to load."[344] Midwest TDUs argue that, where the MISO transmission system cannot provide firm service to all firm customers, Commission precedent requires the consequences to be spread among all firm customers on a nondiscriminatory basis.[345] Midwest TDUs observes that "[s]uch spreading of consequences generally takes the form of redispatch at shared cost, thus effecting a short-term, pro rata curtailment of all energy deliveries affecting the relevant constraint."[346] Midwest TDUs proceed to point out that the consequences of a transmission constraint are not to be imposed on a few disfavored customers.[347] Midwest TDUs add that curtailment pursuant to the Tariff and the resulting short-term loss of delivery is preferable to a loss of a generating resource's capacity value. In this respect, Midwest TDUs claim that under their proposal, transmission customers are protected against bearing the consequences of transmission constraints that become known after committing to a long-term resource. Moreover, Midwest TDUs assert that this is a defining feature of firm transmission service.[348]

179. Midwest TDUs further assert that the Commission erred in failing to require MISO's transmission planning and development to be oriented towards maintaining the feasibility of existing firm capacity delivery commitments by resolving unhedged capacity congestion charges.[349] Midwest TDUs state that the Commission imposed an

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[344] *Id.* at 22-24 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 121 FERC ¶ 61,062, at PP 46-49 (2007)).

[345] *Id.* at 26-27.

[346] *Id.* at 27 (footnote omitted).

[347] *Id.* Midwest TDUs urge the Commission to consider why an LSE that acquires a capacity resource that is later determined to be transmission constrained as a result of another LSE's fleet change should be "singled out to bear the deliverability consequences." *Id.* at 33 (citing *Fla. Mun. Power Agency v. Fla. Power & Light Co.*, 67 FERC ¶ 61,167, at 61,481 (1994); *Midwest Indep. Transmission Sys. Operator, Inc.*, 137 FERC ¶ 61,074, at PP 125-126 (2011)).

[348] *Id.* at 27-28 (citing *Louisville Gas & Elec. Co., et al.*, 114 FERC ¶ 61,282, at P 125 (2006); Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 24 (discussing section 217 of the FPA)).

[349] *Id.* at 52-53.

analogous obligation on MISO in the context of energy congestion.[350] Similarly, Wisconsin PSC argues MISO failed to explain why its proposed capacity market does not include an adequate long-term hedge against congestion such as that provided in Module C of the Tariff.[351] Midwest TDUs add that MISO should be directed to publish long-term forecasts of the Zonal Deliverability Charge and, where those charges are substantial, to identify and construct transmission upgrades to relieve the underlying congestion.[352]

180. Midwest TDUs further contend that the ongoing turnover of the generation fleet in the MISO region does not justify application of the Zonal Deliverability Charge.[353] According to Midwest TDUs, the Commission's apparent intent to make particular entities disproportionately responsible for the consequences of the transmission owners' failure to develop sufficient infrastructure to accommodate future generation mixes is "neither necessary nor helpful to meet[] the ongoing challenge."[354] Instead, Midwest TDUs argue that the Commission should have retained and reinforced the obligation of MISO and the transmission owners to plan and build transmission sufficient to accommodate changing transmission flows. For instance, Midwest TDUs state that reformation of the transmission planning process to take into consideration the source-to-sink deliverability of resources can resolve the impact of fleet turnover.[355]

181. Great River Energy and Dairyland argue that the Commission's rejection of MISO's proposed Grandmother Agreements is particularly unreasonable in comparison to the Commission's approval of the Zonal Deliverability Hedge.[356] Great River Energy

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[350] *Id.* at 53 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,143, at P 193, *order on reh'g*, 121 FERC ¶ 61,063 (2007), *order on reh'g*, 123 FERC ¶ 61,178 (2008)).

[351] Wisconsin PSC Request for Rehearing at 26-27.

[352] Midwest TDUs Request for Rehearing at 53. According to Midwest TDUs, the decision of whether such an upgrade is necessary should be based on a comparison of the net present value cost of the upgrade to the benefits of the upgrade. *Id.*

[353] *Id.* at 65-70.

[354] *Id.* at 65-66.

[355] *Id.* at 67-70.

[356] Great River Energy Request for Rehearing at 9; Dairyland Request for Rehearing at 5.

posits that it is unclear why LSEs should not be granted a similar hedge reflecting their investment in existing transmission infrastructure.

182. Wisconsin PSC argues that the Commission's rejection of MISO's Grandmother Agreements violates the rule against retroactive ratemaking.[357] Wisconsin PSC asserts that "'[p]redictability is an underlying purpose of both the filed rate doctrine and the rule against retroactive ratemaking'" and the test of predictability is whether the ratepayer had sufficient notice that a new charge is likely to be imposed and whether the ratepayer was able to know the consequences of its power procurements decisions."[358] Wisconsin PSC states that the June 11 Order violates the prohibition of retroactive ratemaking by exposing LSEs that have made long-term resource commitments predicated on MISO's existing Tariff provisions to the unhedged Zonal Deliverability Charge. Wisconsin PSC explains that although the Zonal Deliverability Charge applies prospectively, it applies a new charge for the delivery of capacity to resource commitments that were made in the past.[359] Wisconsin PSC adds that LSEs had no notice that their capacity procurements would be subject to a "whole new layer of charges."[360] Wisconsin PSC argues that, among other things, the Commission's determination that the Zonal Deliverability Charge is not a transmission rate and the Commission's decision to grant a two-year grace period in which LSEs may hedge against the Zonal Deliverability Charge by using Grandmother Agreements each illustrate the Zonal Deliverability Charge's retroactive character.[361] As an example, Wisconsin PSC describes a partnership with another LSE in the ownership of the 550 MW Weston power project. Wisconsin PSC argues that the two LSEs share equally pro rata to their respective ownership shares in burdens and benefits, but the partner located in the Weston power project Local Resource Zone continues to pay the same costs while the second partner cannot access its capacity without payment of the Zonal Deliverability Charge.[362]

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[357] Wisconsin PSC Request for Rehearing at 6-14.

[358] *Id.* at 9 (citing *Pub. Utils. Comm'n of Cal. v. FERC*, 988 F.2d 154, at 163-64 (D.C. Cir. 1985); *Towns of Concord v. FERC*, 955 F.2d 67, at 75 (D.C. Cir. 1992)).

[359] *Id.* at 8.

[360] *Id.* at 10.

[361] *Id.* at 11-14.

[362] *Id.* at 11.

183. In further support of the contention that the Commission erred in finding that MISO's proposed Grandmother Agreements would negate the proposed locational market mechanism, parties such as Dairyland and Ameren point out that the Grandmother Agreement exemption proposed by MISO was resource specific.[363] Dairyland states that Grandmother Agreements would be limited to resources for which an LSE has already secured ownership or contractual rights and maintained annual firm transmission service. Going forward, Dairyland states that all new capacity resources would be subject to the Zonal Deliverability Charge. Ameren similarly explains that power supply agreements that would qualify as Grandmother Agreements remain in place for a limited term and expire. Thus, in Ameren's view, the Commission's holding is based on the erroneous presumption that "there are a significant amount of contracts that qualify as Grandmother Agreements that will remain in force indefinitely."[364]

184. A number of parties also challenge the Commission's decision to permit MISO's proposed Grandmother Agreements for a period of two years.[365] For instance, Wisconsin PSC observes that the two-year transition period established by the June 11 Order would not be available to LSEs whose commitments extend beyond two years.[366] Midwest TDUs and APPA argue that the transition period should be lengthened to 10 years.[367] Midwest TDUs explain that such a transition period would be commensurate with the minimum 10-year duration of long-term transmission rights.[368] Midwest TDUs add that such a transition would mitigate any power supply disruption that would result from the Commission's rejection of MISO's proposed Grandmother Agreements. Great River Energy agrees that a 10-year transition period is more appropriate because a two-year transition would not provide LSEs with a sufficient opportunity to observe the effect of

[363] *See, e.g.*, Dairyland Request for Rehearing at 3-5; Ameren Request for Rehearing at 17; Midwest TDUs Request for Rehearing at 44.

[364] Ameren Request for Rehearing at 17.

[365] *See, e.g.*, *id.* at 18; Great River Energy Request for Rehearing at 10-11; Wisconsin PSC Request for Rehearing at 5, 16; APPA Request for Rehearing at 5; Midwest TDUs Request for Rehearing at 51-52.

[366] Wisconsin PSC Request for Rehearing at 16.

[367] Midwest TDUs Request for Rehearing at 51-52; APPA Request for Rehearing at 5.

[368] Midwest TDUs Request for Rehearing at 51-52.

the zonal auction and to properly adjust their resource portfolios.[369] Additionally, Ameren states that the Commission failed to support its decision to set the transition period and that a longer time period would be appropriate.[370] Rather, Ameren states that Grandmother Agreements should remain exempt from the Zonal Deliverability Charge until the agreement expires.

185. Moreover, Midwest TDUs argue that the Commission's rejection of MISO's Grandmother Agreements would constitute an unexplained departure from precedent. Midwest TDUs explain that such a decision would "contrast sharply with the procedural and substantive treatment of baseload resources and 'Grandfather Agreement' rights in hedging energy congestion."[371] Midwest TDUs additionally argue that this injustice would be compounded by the fact that LSEs would have no other way to hedge against the Zonal Deliverability Charge.[372]

ii. <u>Impact on New Network Resources</u>

186. Wisconsin PSC and Midwest TDUs each argue that the Commission's purported failure to extend the Grandmother Agreements to capacity resources developed after the July 2011 cut-off date will adversely affect competition in capacity markets. Notably, Wisconsin PSC contends that the Commission failed to address the destructive effects of an unhedged Zonal Deliverability Charge on competition, the existence of adequate mechanisms other than the Zonal Deliverability Charge to address deliverability concerns, and the need for the Zonal Deliverability Charge in light of those concerns.[373] Wisconsin PSC adds that denying a hedge against the Zonal Deliverability Charge for capacity resources acquired after July 20, 2011 conflicts with the purposes of Multi-

[369] Great River Energy Request for Rehearing at 10-11. Great River Energy adds that the two-year transition period set by the Commission is especially inadequate in light of the long lead time for generation development. *Id.*

[370] Ameren Request for Rehearing at 18.

[371] Midwest TDUs Request for Rehearing at 48 (citing *Wis. Pub. Power Inc. v. FERC*, 493 F.3d 239, 249-50, 269-70 (D.C. Cir. 2007); *Niagara Mohawk Power Corp.*, 100 FERC ¶ 61,247 (2002); *Central Hudson Gas & Elec. Corp.*, 86 FERC ¶ 61,062, at 61,217-18 (1999)).

[372] *Id.* at 48-49. Midwest TDUs add that the Locational Requirements Order does not foreclose such an outcome.

[373] Wisconsin PSC Request for Rehearing at 17-18.

Value Project cost allocation, Attachment X and Module B of the Tariff, and Order No. 1000, all of which Wisconsin PSC suggests are designed to promote regional and interregional delivery.[374]

187. Regarding the effect of the June 11 Order on competition, Midwest TDUs additionally argue that the Commission's purported failure to extend the Grandmother Agreements to capacity resources developed after the July 2011 cut-off date will wrongly balkanize and truncate the capacity market in the MISO region.[375] Midwest TDUs contend that the Zonal Deliverability Charge could cause a disconnect whereby resources are characterized as deliverable throughout MISO for purposes of determining market-based rate authority, "while constraints that effectively require local purchasing confer market power within more narrow markets."[376] Such a disconnect would cause power supply costs to rise, according to Midwest TDUs, by encouraging local, short-term capacity transactions. Midwest TDUs add that allowing LSEs to become exposed to the Zonal Deliverability Charge as a result of future modifications of the zonal boundaries will exacerbate this result.

188. Moreover, Wisconsin PSC contends that the unhedged application of the Zonal Deliverability Charge against any capacity resource will impair the ability of smaller LSEs to share risk associated with developing new capacity resources. Wisconsin PSC states that the Zonal Deliverability Charge will limit the number of potential partners to those LSEs residing in the same Local Resource Zone. Further, Wisconsin PSC adds that the Zonal Deliverability Charge would limit "the likelihood of a timely convergence of capacity needs that is a prerequisite to [such] a joint venture."[377]

iii. <u>General Impacts: Discrimination, Markets, and Rates</u>

189. Because the Zonal Deliverability Charge applies to interzonal transactions, but not to intrazonal transactions, Wisconsin PSC concludes that the Commission's holding approves "plain and simple 'old-school' discrimination."[378]

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[374] *Id.* at 19-20 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323).

[375] Midwest TDUs Request for Rehearing at 55-58.

[376] *Id.* at 55.

[377] Wisconsin PSC Request for Rehearing at 22.

[378] *Id.* at 21-22.

190. Midwest TDUs explain that until now, the MISO capacity resource construct has been founded upon Order Nos. 888's and 890's first-come, first-served physical rights. Midwest TDUs fault the Commission for adopting a construct in which transmission customers are asked to take existing and later-arising transmission constraints as unyielding parameters and modify their resource selections to live within them. Midwest TDUs contend that the Commission-approved construct encourages MISO and its transmission owners to visit the consequences of transmission inadequacy on transmission-dependent utilities and to transfer to transmission owners the capacity cost savings that transmission dependent utilities would otherwise enjoy from lower cost capacity resources located in neighboring zones. Midwest TDUs argue that market participant transmission owners will therefore profit on the generation side if they apply their influence over transmission planning so as to maintain import constraints into their zones.[379]

191. Wisconsin PSC and Midwest TDUs assert that the Zonal Deliverability Charge "is a 'pancake' on top of the base network charge," in violation of the Commission's statement in Order No. 2000 that tariffs must not result in customers paying multiple access charges to recover capital costs.[380] Wisconsin PSC also contends that locational marginal pricing is the market mechanism for clearing congestion and ensuring deliverability.[381] According to Wisconsin PSC, MISO has thus failed to justify application of the Zonal Deliverability Charge on top of the basic network charge and the locational marginal price.

iv. <u>Implications for Commission's Ratemaking Authority</u>

192. Wisconsin PSC also argues that the Commission should grant rehearing because the Zonal Deliverability Charge is ultra vires of sections 205 and 206 of the FPA because it is a charge that is "divorced from any service."[382] According to Wisconsin PSC, the June 11 Order states that the Zonal Deliverability Charge is not a payment for firm transmission service.[383] Further, Wisconsin PSC states that the Zonal Deliverability

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[379] Midwest TDUs Request for Rehearing at 31-32.

[380] Wisconsin PSC Request for Rehearing at 20 (citing Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,174); Midwest TDUs Request for Rehearing at 44.

[381] Wisconsin PSC Request for Rehearing at 26-27.

[382] *Id.* at 28.

[383] *Id.* (citing June 11 Order, 139 FERC ¶ 61,199 at P 105).

Charge does not compensate recipients for any generation or ancillary services. Rather, Wisconsin PSC notes that the Zonal Deliverability Charge is intended to indicate the relative valuation of resources in zones and to provide a price signal to LSEs.[384] However, Wisconsin PSC asserts that the FPA does not authorize MISO to impose charges based on the value of a service it does not provide.[385] Additionally, Wisconsin PSC claims that there is no direct correlation between the cost of transmission between Local Resource Zones and the price separation between zones, upon which the Zonal Deliverability Charge is based.[386] As a result, Wisconsin PSC concludes that the Zonal Deliverability Charge does not fall within the authority conferred by the FPA.[387]

v. <u>Section 217 and Order No. 681 Implications</u>

193. A number of parties argue that the Commission's approval of MISO's Zonal Deliverability Charge and the rejection of MISO's proposed Grandmother Agreements contravenes both section 217 of the FPA and Order No. 681.[388] For instance, Midwest TDUs aver that application of the Zonal Deliverability Charge to LSEs without the protection of the proposed Grandmother Agreements will abrogate what would otherwise be firm transmission service in violation of section 217 of the FPA.[389] According to Midwest TDUs, in order to qualify as firm transmission service under section 217, the Commission has previously stated that such service must be firm as to both the physical and financial components.[390] Specifically, Midwest TDUs claim that the Commission's rejection of the proposed treatment of Grandmother Agreements jeopardizes the financial

[384] *Id.* at 29 (citing June 11 Order, 139 FERC ¶ 61,199 at P 105).

[385] *Id.*

[386] *Id.*

[387] *Id.* at 30.

[388] *See, e.g.*, Midwest TDUs Request for Rehearing at 29; Wisconsin PSC Request for Rehearing at 21-22; APPA Request for Rehearing at 4-5; Great River Energy Request for Rehearing at 8.

[389] Midwest TDUs Request for Rehearing at 29.

[390] *Id.* (citing Order No. 681, FERC Stats. & Regs. ¶ 31,226 at P 82).

component of customers' firm transmission rights[391] and further requires LSEs to take existing and later-arising transmission constraints as unyielding parameters.[392]

194. Midwest TDUs further note that the right of delivery includes the right of delivery of capacity, not just energy, and capacity is a component of firm physical rights for LSEs' long-term power arrangements.[393] Midwest TDUs assert that section 217 obligates the Commission to exercise its authorities that take into account the policies expressed in sections 217(b)(1), (b)(2), and (b)(3) with respect to the many long-held resources that will be submitted for capacity resource credit under MISO's new resource adequacy construct. Midwest TDUs argue that by vitiating the firm transmission rights that Congress expressly called for the Commission to preserve, and making no provision for equivalent financial or tradable rights in their place, the June 11 Order violates this requirement.[394]

195. APPA adds that capacity is a component of both physical firm transmission rights as well as LSEs' service obligations.[395] Furthermore, Midwest TDUs and Wisconsin PSC each posit that section 217 and Order No. 681 require that MISO's proposed Grandmother Agreements should have been extended to all capacity resources, rather than only resources under construction prior to July 20, 2011.[396]

196. Midwest TDUs fault the June 11 Order for stating that LSEs remain eligible for Auction Revenue Rights while also stating that Order No. 681 is not germane to MISO's proposal.[397] Midwest TDUs consider these statements to be contradictory and therefore unsustainable.

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[391] *Id.*

[392] *Id.* at 31.

[393] *Id.* at 16-17 (citing section 28.3 of the MISO Tariff).

[394] *Id.* at 19.

[395] APPA Request for Rehearing at 4-5.

[396] Midwest TDUs Request for Rehearing at 53-54; Wisconsin PSC Request for Rehearing at 21-22.

[397] Midwest TDUs Request for Rehearing at 20.

vi. Compliance

197. Midwest TDUs contend that MISO's proposal complied with the Commission's prior directives in the Locational Requirements Order and the Locational Requirements Compliance Order.[398] According to Midwest TDUs, the June 11 Order relied heavily on the proposition that under the Locational Requirements Order and the Locational Requirements Compliance Order, MISO was left with no choice but to impose the unhedged Zonal Deliverability Charge.[399] To the contrary, Midwest TDUs state that the Commission's prior directives did not require such a proposal by MISO or otherwise prohibit Grandmother Agreements. Building on the premise that the Commission could not reject the proposed Grandmother Agreements without first making a reasoned finding that the proposal failed to satisfy the requirements of section 205 of the FPA, Midwest TDUs conclude that the June 11 Order must be overturned because the Commission made no such reasoned finding.[400]

198. Specifically, Midwest TDUs allege that the Commission engaged in "unjustifiable revisionism" rather than reasoned decision-making in holding that the MISO's proposed Grandmother Agreements were inconsistent with the Commission's prior directives in the Locational Requirements Order and the Locational Requirements Compliance Order.[401] Midwest TDUs state that the Locational Requirements Order is the sole authority that may be considered in determining whether MISO's Grandmother Agreements fell within the range allowed by the Locational Requirements Order.[402] Midwest TDUs proceed to argue that on its face, the Locational Requirements Order did not require MISO to assess the unhedged Zonal Deliverability Charge.[403] Midwest TDUs add that the Commission subsequently mischaracterized the Locational Requirements Order as requiring MISO to establish "market mechanisms such as locational pricing and locational market rules that provide incentives for market participants to obtain sufficient local resources to ensure reliability."[404] According to Midwest TDUs, the Commission clarified this

[398] *Id*. at 33-39.

[399] *Id.* at 33.

[400] *Id.*

[401] *Id.* at 38.

[402] *Id.* at 37.

[403] *Id.* at 34-37.

[404] *Id.* at 37 (quoting Locational Requirements Compliance Order, 131 FERC ¶

(continued...)

mischaracterization on rehearing when it observed that "[n]othing in the Commission's [Locational Requirements] Compliance Order was intended to modify [MISO's] obligations under the [Locational Requirements Order]."[405] As a result of that clarification, Midwest TDUs reason that the Locational Requirements Order was not subsequently revised by the Commission and was left "unchanged and extant as the only statement" of MISO's compliance requirement.[406]

c. Commission Determination

199. We deny rehearing and affirm the Commission's findings in the June 11 Order for the reasons discussed below.

i. Grandmother Agreements

200. We do not agree that the Zonal Deliverability Charge that results from locational market prices is an arbitrary punishment or an inappropriate penalty on LSEs that have made long-term commitments to resources, as well as obtaining firm transmission service to guarantee deliverability of the resource's capacity to the LSE. The Commission determined in the June 11 Order, and we affirm here, that locational market prices are just and reasonable. None of the parties raising issues regarding Grandmother Agreements argue that locational market prices are an unreasonable basis for determining the cost of capacity. Rather, parties argue that they should receive an exemption from the impact of locational market prices because of special circumstances. The premise of their request for exemption is that LSEs with long-term resource commitments have firm transmission service that ensures deliverability of capacity from the resource to the load. We do not see this premise to be relevant to what constitutes a reasonable cost of capacity. Locational market prices ensure that LSEs pay for reliability based on the cost of reliability where that service is provided, namely at the load location. The resource location is not where the reliability service is being provided, and therefore the cost of the resource – at the resource location – under long-term commitment does not constitute the cost of capacity. MISO's annual local reliability analysis for each Planning Year is not based on long-term firm transmission rights. Rather, MISO annually evaluates the local clearing requirements in each zone based on an assessment of the local clearing requirement for resources, local capacity import limits and local capacity export limits.

61,228 at P 24).

[405] *Id.* (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 135 FERC ¶ 61,081, at PP 6, 9 (2008)).

[406] *Id.* at 38.

201. As the foregoing makes clear, the fact that LSEs have already paid for deliverability in the firm transmission service charge is not germane to the cost of capacity. When LSEs pay locational market prices, they are not paying for transmission service. Instead, they are paying a locational market price based on the market-clearing price for capacity in the local zone. Therefore, the locational market price is not another layer of costs or "pancaked costs" on top of the transmission service charge. Also, the fact that MISO undertakes transmission planning is not germane to MISO's resource adequacy construct, contrary to Midwest TDUs' assertion.[407] The Commission has determined that the relevant reliability analysis in MISO's resource adequacy construct is the annual reliability analysis of local clearing requirements, capacity import limits and capacity export limits discussed above. Accordingly, in response to Midwest TDUs, we do not consider it an error that the June 11 Order did not require modifications to the transmission planning process to account for the MISO resource adequacy construct. With regard to Midwest TDUs' interest in an enhanced transmission planning process that would be implemented instead of locational market prices and a Zonal Deliverability Charge, our task in this proceeding is not to determine the reasonableness of alternative proposals. Rather, the Commission's task in the June 11 Order was to evaluate the reasonableness of MISO's proposal, which it did, and therefore we see no need for consideration of further options. We also find Midwest TDUs' concern with who is responsible for transmission planning and who must bear the costs of transmission construction to be beyond the scope of this proceeding.

202. While Great River Energy asserts that the proposed Grandmother Agreement exemption is reasonable because it reflects the investment of LSEs in the transmission infrastructure,[408] that is not the basis of the proposed exemption. Rather, the proposed exemption is based on the maintenance of firm transmission service.[409] As discussed, firm transmission rights are not the basis for analyzing reliability requirements and therefore have no bearing on the cost of capacity. Accordingly, Great River Energy's

[407] *Id.* at 47.

[408] Great River Energy Request for Rehearing at 9.

[409] *See* MISO FERC Electric Tariff, Module A, Grandmother Agreements ("Ownership of, or executed contractual rights to Planning Resources (including generating facilities under construction prior to July 20, 2011 that subsequently become Planning Resources) that are in place prior to July 20, 2011 and maintain annual firm transmission service from such Resources to load in a different [Local Resource Zone] which will provide an LSE with an exemption from the Zonal Deliverability Charge for the volume of such Planning Resources.")

analogy between the Grandmother Agreement exemption and the Zonal Deliverability Charge Hedge is misplaced. Whereas the Zonal Deliverability Charge Hedge is based on the capacity import limit impacts of a transmission expansion, the Grandmother Agreement exemption has no such analysis but rather provides an exemption for any firm transmission service held by an LSE. The Zonal Deliverability Charge Hedge will only allow an LSE to avoid the Zonal Deliverability Charge if a market participant funds a transmission system upgrade that increases the capacity import limit for a Local Resource Zone where the sink is located.[410] As discussed in section VI.F.3.c below, the Commission approved this aspect of MISO's proposal because the Zonal Deliverability Charge Hedge would appropriately recognize the economic value of transmission development that relieves constraints. In comparison, MISO's proposal would not require Grandmother Agreements to have funded transmission upgrades that increase capacity import limits. Thus, while the Commission's acceptance of the Zonal Deliverability Charge Hedge was appropriate to incentivize the development of new transmission capacity because it explicitly required such development, the agreements for which MISO proposes to give Grandmother treatment include no such criterion justifying similar treatment.

203. We do not consider Ameren's argument that retail customers would have to pay additional costs for the Zonal Deliverability Charge to be a basis for a Grandmother Agreement exemption. Ameren's contention rests on the premise that retail customers should not have to pay any more for reliability services than they pay currently and therefore the Zonal Deliverability Charge is unreasonable, a position with which we disagree, as discussed. The locational market prices that result in Zonal Deliverability Charges are reasonable rates for the provision of reliability that benefits load.

204. With respect to Wisconsin PSC's arguments that the Commission's holding approves "plain and simple 'old-school' discrimination," the Commission has consistently recognized that undue discrimination is present where two or more similarly situated entities are treated differently.[411] In fact, the Commission has broad discretion in determining when discrimination is undue.[412] The two partners in Wisconsin PSC's Weston power project example are not similarly situated, contrary to Wisconsin PSC's assertion. One partner is near the power project and therefore is paying the same local zone price for reliability that the resource is receiving. The other partner that is distant

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[410] June 11 Order, 139 FERC ¶ 61,199 at P 116.

[411] *See, e.g.*, *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076 at P 369.

[412] *Transmission Access Policy Study Gr. v. FERC*, 225 F.3d 667, 721 (D.C. Cir. 2000); *Cities of Bethany v. FERC*, 727 F.2d 1131, 1138 (D.C. Cir. 1984).

from the power project is paying a different price for reliability based on the cost of capacity in its local zone. The basis for the difference in the cost of capacity is reasonable since it reflects the locational cost of capacity.

205. We consider Midwest TDUs' arguments that transmission owners are better positioned to avoid the Zonal Deliverability Charge than transmission dependent utilities because of their ability to rate-base transmission solutions and to build baseload units in their load zone[413] to be speculative at this point. In this proceeding we have found no potential for undue discrimination and no record evidence that transmission dependent utilities are being discriminated against.

206. Midwest TDUs additionally mischaracterize the Commission's statement regarding the ongoing turnover of the generation fleet in the MISO region as the concern underlying the Commission's approval of the Zonal Deliverability Charge.[414] In introducing the Commission's discussion of the locational market mechanism proposed by MISO, the Commission explained in the June 11 Order that MISO's proposal would ensure that sufficient capacity is available in import-restricted regions.[415] The Commission then proceeded to highlight its historic concern with ensuring capacity deliverability in MISO. Notably, the Commission elaborated on this concern, stating that although "MISO has previously argued that its transmission planning processes have been sufficient to date in addressing constraints . . . the Commission's concern has been that MISO's existing processes may be inadequate to ensure continued deliverability."[416] In this context, the Commission observed that future changes to the generation mix may create new constraints. Thus, taken in its proper context, it is clear that the Commission did not rely on the ongoing turnover of generation resources in the region as the basis for approving the Zonal Deliverability Charge.

207. Wisconsin PSC's argument that the imposition of a Zonal Deliverability Charge constitutes unlawful retroactive ratemaking is based on the premise that "LSEs have made long term Incumbent Resource commitments predicated on MISO's then existing Tariff mechanisms for transmission service at the time the commitment was made," and "The retroactive application of the [Zonal Deliverability Charge] changes the rules of the

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[413] Midwest TDUs Request for Rehearing at 43.

[414] *See id.* at 65-70.

[415] June 11 Order, 139 FERC ¶ 61,199 at P 72.

[416] *Id.*

game after it has already started."[417] However, changing the rules prospectively does not mean that the Zonal Deliverability Charge was applied retroactively.

208. The filed rate doctrine and the corresponding prohibition of retroactive rate making bars a regulated seller from collecting a rate other than the one on file with the Commission and prohibits imposing a rate increase for service already provided.[418] The rule generally prohibits entities from altering a rate retroactively or adjusting current rates to make-up for a utility's over-collection or under-collection.[419] No such alteration of a previous rate is presented by the new Zonal Deliverability Charge, which undisputedly will be applied only prospectively after the Commission determines its justness and reasonableness. Wisconsin PSC's position – that LSEs did not have notice of the Zonal Deliverability Charge at the time their resources went into service, and therefore the Commission engaged in retroactive ratemaking when it accepted the Zonal Deliverability Charge and rejected the Grandmother Agreement exemption – is an argument for a guaranteed cost of capacity for the life of a resource, which is clearly not required by the filed rate doctrine or the rule against retroactive ratemaking. The relevant factor is that the LSEs had notice of the Zonal Deliverability Charge when it was proposed and before it goes into effect. Wisconsin PSC's position is an unreasonable standard inasmuch as such a definition would bar any changes in rates that may impact the cost of these resources to the LSE over the life of the resources. As discussed more fully above, the Commission determined in the June 11 Order and we are affirming here that the Zonal Deliverability Charge is just and reasonable because it accurately reflects the locational cost of capacity. We consider it appropriate that the cost of capacity reflect the locational cost of capacity, and therefore it is unreasonable to suspend locational reliability prices for the entire life of a resource. For these reasons, we reject Wisconsin PSC's interpretation of the filed rate doctrine and retroactive ratemaking.

209. We are not persuaded by the arguments of parties that Grandmother Agreements should be exempted from the Zonal Deliverability Charge because they do not cover all the resources committed by LSEs and that they will eventually terminate. No party has provided any evidence to dispute the Commission's finding in the June 11 Order that the Grandmother Agreement proposal would exempt most resources from the Zonal Deliverability Charge.[420] The only information we have received in this regard are

[417] Wisconsin PSC Request for Rehearing at 8.

[418] *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 577-78 (1981).

[419] *See, e.g.*, *Towns of Concord*, 955 F.2d 67 at 71 & n.2.

[420] June 11 Order, 139 FERC ¶ 61,199 at P 113.

concerns that the Zonal Deliverability Charge will result in supply disruptions and harm the competitive conditions in MISO. We can only infer from these concerns that the long-term resources committed under Grandmother Agreements are at least a significant portion of the resources in MISO. In any case, the position of parties does not provide a basis for an exemption – whatever the portion of resources affected by the June 11 Order. The Commission found locational market prices to be reasonable in the June 11 Order, and found no basis for an exemption. We affirm those findings in this order and accordingly we reject the requests for rehearing.

210. We also affirm the two-year transition for Grandmother Agreements in the June 11 Order. We have no basis in the record of this proceeding for assuming that locational market prices and the Zonal Deliverability Charge will cause supply disruptions, as Midwest TDUs claim in their argument that the transition period needs to be longer, and therefore we are not persuaded to extend the transition period on this basis. We also do not consider the 10-year term for long-term transmission rights cited by Midwest TDUs to be a basis for extending the transition period since long-term transmission rights do not apply to capacity, as discussed above. Responding to Great River Energy, we affirm the June 11 Order's determination that two years is sufficient for market participants to adjust their resource portfolios and plan for additional resources. By setting a two-year transition, the Commission was not expecting market participants to build new generation resources during the transition period. Rather, the transition period objective for new resources was that market participants would *plan* for additional resources only, as the Commission stated.

211. We clarify for Ameren that, as stated in the June 11 Order, the purpose of the transition is to provide time for adjusting portfolios and planning for additional resources. We consider two years to be a reasonable period of time to accomplish these tasks.

212. We also disagree with Midwest TDUs' position that the June 11 Order constitutes an unexplained departure from precedent.[421] As an initial matter, none of the precedent cited by Midwest TDUs is binding in this case because none of those decisions exempted LSEs from a locational market mechanism such as the Zonal Deliverability Charge.

213. Also, unlike the Grandmother Agreements at issue in this proceeding, the *Wisconsin Public Power* precedent cited by Midwest TDUs addressed the modification of agreements with *Mobile-Sierra*[422] clauses that prohibit the Commission from abrogation

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[421] *See* Midwest TDUs Request for Rehearing at 48 (citing *Wis. Pub. Power Inc. v. FERC*, 493 F.3d 239 at 249-50, 269-70; *Niagara Mohawk Power Corp.*, 100 FERC ¶ 61,247; *Central Hudson Gas & Elec. Corp.*, 86 FERC at 61,217-18).

[422] *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956);

(continued...)

or modification of freely negotiated private contracts setting service rates unless required by the public interest, since the tariff would have altered Grandfather Agreement parties' bargain by causing cost shifts between them due to pervasive disruption of their scheduling practices. By contrast, the Commission's determination with respect to Grandmother Agreements does not modify any existing agreements and thus does not involve the same *Mobile-Sierra* considerations. Accordingly, we consider the *Wisconsin Public Power* precedent cited by Midwest TDUs to be distinguishable from the Grandmother Agreements at issue in this proceeding.

ii. <u>Impacts on New Network Resources</u>

214. Wisconsin PSC's and Midwest TDUs' concerns regarding the competitive impacts of locational market pricing must be assessed in the context of the purpose of a resource adequacy construct, namely reliability. The relevant analysis for reliability in MISO's resource adequacy construct is the annual local reliability analysis of local clearing requirements, capacity import limits and capacity export limits. This analysis goes beyond simply providing firm transmission service and transmission planning, as discussed. While Wisconsin PSC's and Midwest TDU's position would encourage competition across all network resources, it would not account for local resource availability or local zone capacity limits, thereby negating the purpose of a resource adequacy construct to ensure reliability on the peak day. For this reason, we affirm the Commission's determination in the June 11 Order that the Zonal Deliverability Charge is reasonable.

215. Furthermore, such arguments fail to take account of the fact that all market participants will continue to have equal access to the transmission facilities in the MISO region. In this respect, the Zonal Deliverability Charge, absent the exemption offered by MISO's proposed Grandmother Agreements, is not at odds with Attachment X or Module B of the Tariff, or with MISO's proposed Multi-Value Project cost allocation provisions. Wisconsin PSC's unsubstantiated allegations that the June 11 Order conflicts with these authorities is unpersuasive.

216. Nor are we persuaded by Wisconsin PSC's and Midwest TDUs' assertion that the Zonal Deliverability Charge will discourage the planning and construction of transmission between zones. The Commission's requirements in support of regional transmission planning in Order Nos. 890 and 1000 remain in effect. Wisconsin PSC and Midwest TDUs provide no explanation of how these requirements would no longer be effective, and therefore we have no basis for concluding that the Zonal Deliverability Charge would negate the impact of these orders. In fact, the Zonal Deliverability Charge

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FPC v. Sierra Pac. Power Co., 350 U.S. 348 (1956).

Hedge encourages the planning and construction of transmission between zones because it ensures that an LSE can avoid the Zonal Deliverability Charge if the LSE builds capacity that increases the import limit into a zone.

217. The new network resource in Wisconsin PSC's example[423] will receive a Zonal Deliverability Charge Hedge, and therefore will not be impacted by the Zonal Deliverability Charge, if it upgrades a transmission line to relieve a constraint when it applies for firm transmission service. However, obtaining a Generator Interconnection Agreement and receiving a designation as a network resource only indicates that the resource can access the MISO transmission network. The fact that a new network resource has firm transmission service, such as network integration service as noted by Midwest TDUs,[424] or that MISO undertakes transmission planning, only has a bearing on the locational price paid for reliability to the extent that they impact the designation of zones and the locational price paid for reliability. Neither firm transmission nor MISO transmission planning are guarantees that there will be no price separation between a new network resource and load.

218. With regard to Wisconsin PSC's concerns with the practical effects of a Zonal Deliverability Charge without a hedge for new network resources,[425] we do not dispute the claim that such a charge may have an impact on the participation of LSEs in various resource projects, particularly those that are outside constrained zones. However, participation in any and all projects is not an appropriate goal.

iii. General Impacts: Discrimination, Markets and Rates

219. In MISO's resource adequacy construct, all LSEs pay a locational market price based on the location of the LSE's load where the reliability benefit of resource adequacy is being provided. Therefore, we see no basis for Wisconsin PSC's claim that the Zonal Deliverability Charge discriminates against inter-zonal transactions. The Zonal Deliverability Charge simply ensures that LSEs with resources outside a constrained zone are paying a price for reliability that reflects the cost of capacity where reliability is being provided. Contrary to Wisconsin PSC's characterization, the Zonal Deliverability Charge is not a transmission service charge and therefore payment of the Zonal Deliverability Charge does not constitute paying a dissimilar rate for similar service.

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[423] Wisconsin PSC Request for Rehearing at 24.

[424] Midwest TDUs Request for Rehearing at 41.

[425] Wisconsin PSC Request for Rehearing at 23.

220. Wisconsin PSC's and Midwest TDUs' reliance on Order Nos. 888, 890, and 2000 is misplaced. Each of the cited authorities ensures that transmission customers have non-discriminatory access to transmission service.[426]

221. Midwest TDUs argue that the Zonal Deliverability Charge could provide an incentive for vertically-integrated transmission owners to profit from constraints. But the Commission has established policies to counteract the incentives of transmission owners to exercise market power. For example, the revenues and profits of transmission owners are regulated under cost-of-service regulation, so transmission owners cannot profit in the long run from constraints created from failing to expand transmission capacity. Moreover, Order No. 1000 provides a process to expand transmission capacity when and where additional transmission capacity is needed. Such behavior would not be rational when there are programs and provisions encouraging transmission construction, as discussed above. Accordingly, we consider Midwest TDUs' concern to be speculative.

222. We find no basis for Wisconsin PSC's and Midwest TDUs' claim that the Zonal Deliverability Charge is a "pancake" rate on top of network transmission charges. As discussed, the Zonal Deliverability Charge is not a transmission charge, and therefore it is not possible for the Zonal Deliverability Charge to be added to network transmission charges, and therefore there are no implications for Order No. 2000. The Zonal Deliverability Charge does not undermine the basis for treating the MISO region as a single market for market-based rate purposes since it is not a transmission charge. As for the locational marginal price congestion charge, that charge applies to the cost of congestion for the delivery of energy whereas the Zonal Deliverability Charge is a capacity cost based on the locational value of resources.

iv. Implications for Commission's Ratemaking Authority

223. With respect to Wisconsin PSC's assertion that the Zonal Deliverability Charge is ultra vires of section 205 and 206, we note that Wisconsin PSC did not argue that the Zonal Deliverability Charge is contrary to sections 205 and 206 of the FPA in either its initial comments or its subsequent answer prior to the issuance of the June 11 Order. The Commission has previously noted that a request for rehearing is not the appropriate venue

[426] *See* Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 30,995 (describing the goal of Order No. 888 and Order No. 889 as ensuring "that customers have the benefits of competitively priced generation" through access to non-discriminatory open access transmission services); Order No. 890, FERC Stats & Regs. ¶ 31,241 at P 1.

to protest such issues in the first instance.[427] Raising such issues for the first time on rehearing is disruptive to the administrative process and denies parties the opportunity to respond.[428]

224. While we are rejecting the rehearing request on this issue based on procedural grounds, we will nonetheless respond to the merits of Wisconsin PSC's position. The Zonal Deliverability Charge ensures that an LSE's payment for capacity is based on the locational cost of capacity where the reliability service is being provided to load. LSEs that designate a resource in their fixed resource adequacy plan in each Planning Year are designating resources that have been interconnected and have been determined to have deliverability to the MISO network. However, the cost of capacity is appropriately based on the locational cost of capacity in the load zone – where the reliability service is being provided – as reflected in a market-based charge that recognizes the impact of transmission constraints and local reliability requirements. While Wisconsin PSC may argue that an LSE in a constrained zone only purchased capacity from a resource outside the zone and therefore should only pay the cost of that resource, nonetheless the LSE is being provided reliability at its load location, not at the resource location. A price based solely on the cost of this resource ignores the cost of capacity where the reliability service is provided and therefore ignores the impacts of transmission constraints and local reliability requirements that impact reliability where it is provided.

v. <u>Section 217 and Order No. 681 Implications</u>

225. We affirm the Commission's determination in the June 11 Order that the implementation of Zonal Deliverability Charges have no implications for the operation of transmission service under Module B and do not preclude LSEs from obtaining long-term firm transmission rights under FPA section 217.[429] Generally, section 217 protects firm transmission rights to serve native load customers. While Midwest TDUs challenge the Commission's determination on the grounds that it violates section 217, the basis for their challenge is their interpretation of Order No. 681, specifically the statement in Order No. 681 that such service must be firm as to both the physical and financial components. Midwest TDUs assert that the Zonal Deliverability Charge violates this requirement by imposing an additional, unavoidable price for delivering capacity across zonal borders

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[427] *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,030 (2009).

[428] *Enron Power Marketing, Inc., et al.*, 122 FERC ¶ 61,015, at P 64 n.98 (2008); *Midwest Indep. Transmission Sys. Operator, Inc.*, 117 FERC ¶ 61,113, at P 188 (2006) (denying rehearing of new issues as outside the proper scope of the proceeding).

[429] June 11 Order, 139 FERC ¶ 61,199 at P 104.

that makes the transmission right to delivery of these resources non-firm. However, as pointed out in the June 11 Order, Order No. 681 is restricted to congestion management in energy and ancillary services markets and their impacts on long-term firm transmission rights.[430] Therefore, Order No. 681 does not provide a basis for a hedge from capacity costs. Thus, we find no basis for Midwest TDUs' position that section 217 applies to the Zonal Deliverability Charge and requires the Commission to make provision for financial or tradable rights.

226. Nor do we find any basis for Wisconsin PSC's claim that Order No. 681 defines financial transmission rights as not only an energy market instrument, but any of various forms of financial transmission rights that exist in organized electricity markets[431] – implying that Order No. 681 applies to capacity transactions. The cited paragraph in Order No. 681 makes clear that it only applies to energy market transactions, the impacts of locational marginal pricing and the use of various forms of financial transmission rights in energy markets. In a similar vein, we clarify that, in the June 11 Order, the Commission found that energy hedging is not germane to MISO's proposal including the Zonal Deliverability Charge.[432] While LSEs can continue to obtain Auction Revenue Rights, those rights apply only to congestion in energy markets.

vi. Compliance

227. We find Midwest TDUs' assertion that Grandmother Agreements are consistent with the Commission's prior directives to be inapposite. The only issues in this proceeding are whether MISO's proposed locational mechanism is in compliance with those directives and whether the MISO proposal is just and reasonable. The Commission found that the Grandmother Agreements feature in MISO's proposal was not reasonable because it exempts LSEs from taking into account congestion that limits aggregate deliverability – contrary to the purpose of MISO's proposed locational mechanism. The Commission did not have before it a range of compliance options to evaluate, nor was it the Commission's task in the June 11 Order to consider a range of potential compliance options.

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[430] *Id.* P 106 (citing Order No. 681, FERC Stats. & Regs. ¶ 31,226 at P 24).

[431] Wisconsin PSC Request for Rehearing at 22 (citing Order No. 681, FERC Stats. & Regs. ¶ 31,226 at P 5, n.11).

[432] June 11 Order, 139 FERC ¶ 61,199 at PP 104, 106.

3. Zonal Deliverability Charge Hedge

a. June 11 Order

228. In the June 11 Order, the Commission accepted MISO's proposed Zonal Deliverability Charge Hedge.[433] The Commission found that MISO's proposal appropriately recognizes the economic value of new capacity that mitigates constraints, thereby improving deliverability of resources to serve peak demand in constrained zones. The Commission explained that market participants who fund Network Upgrades that increase the import capability into a Local Resource Zone should have priority in receiving the financial benefit stemming from their investments.

b. Requests for Rehearing

229. Midwest TDUs argue that the Commission erred in rejecting Midwest TDUs' proposal to require MISO to hedge then-existing resource commitments against the financial consequences of MISO's modifying the zonal boundaries. Further, Midwest TDUs contend that the Commission wrongly rejected its proposal as a collateral attack on the Locational Requirements Order and the Locational Requirements Compliance Order.[434]

230. Midwest TDUs further assert that Zonal Deliverability Charge Hedges should not be tied to participant-funded network upgrades.[435] First, Midwest TDUs contend that the Commission failed to adequately address their argument that MISO's proposed Zonal Deliverability Charge Hedge is illusory. Midwest TDUs explain that, in its protest, it argued that MISO studies new network resources only for aggregate deliverability, and does not consider resources' source-to-sink deliverability. As a result, Midwest TDUs state that an LSE's request for transmission service would not trigger a study of whether to add import capacity. Thus, Midwest TDUs conclude that, under the circumstances, an LSE will never be able to acquire a Zonal Deliverability Charge Hedge because such a

[433] *Id.* PP 134-140. The Zonal Deliverability Charge Hedge is a mechanism that permits an LSE to avoid Zonal Deliverability Charge assessments through investment in new or upgraded Transmission System facilities which are a result of approved firm transmission service requests where the LSE's Planning Resource and load are in separate Local Resource Zones. MISO, Tariff, Definitions, § 30.0.

[434] Midwest TDUs Request for Rehearing at 57-58.

[435] *Id.* at 58-65.

request would not ever lead to an increase in the Capacity Import Limit.[436] According to Midwest TDUs, the Commission dismissed this argument on the ground that "if a network resource designation request somehow does lead to a Network Upgrade identified to that request, then MISO will measure the resulting Capacity Import Limit . . . increase."[437] Midwest TDUs assert that the Commission's response is a non sequitur.

231. Second, Midwest TDUs contend that the Commission erroneously approved MISO's proposal to tie Zonal Deliverability Charge Hedges to participant-funded upgrades.[438] Midwest TDUs state that they argued in their protest that tying Zonal Deliverability Charge Hedges to participant-funded upgrades does not result in hedging proportionate to transmission service payments. However, Midwest TDUs argue that the Commission dismissed this concern "on the spurious ground that 'MISO's statement was in reference to the zonal deliverability benefit and its pro rata allocation—not the Zonal Deliverability Charge Hedge. This is clear from the language in . . . Hillman's affidavit.'"[439] Midwest TDUs therefore conclude that the language at issue "really does assert that [Zonal Deliverability Charge] Hedges should be tied to incremental transmission payments" and the Commission was wrong to dismiss Midwest TDUs' substantive arguments by contending otherwise.[440] Midwest TDUs urge the Commission to find that Zonal Deliverability Charge Hedges are, in fact, illusory.

232. Midwest TDUs assert that Zonal Deliverability Charge Hedges should relate to the timely designation of a long-term-firm resource and that granting a hedge to LSEs who pay to expand capacity across a constrained interface will create a perverse incentive to use constrained interfaces. Midwest TDUs also explain that the size of an import limit increase relates only tenuously to the size of a newly imported resource. Thus, tying Zonal Deliverability Charge Hedges to the size of the upgrade size would either unjustifiably confer a windfall to or expose an LSE to the Zonal Deliverability Charge. In addition, Midwest TDUs state that network resources that do not trigger network upgrades are not free-riders that should be subject to the Zonal Deliverability Charge in order to receive assured deliverability of their capacity resources. Rather, Midwest TDUs

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[436] *Id.* at 59 (citing Midwest TDUs Protest, Docket No. ER11-4081-000, at 27-28 (filed Sept. 15, 2011)).

[437] *Id.* (citing June 11 Order, 139 FERC ¶ 61,199 at P 135).

[438] *Id.* at 61-65.

[439] *Id.*at 61.

[440] *Id.* at 62.

reiterate their position that the rate for firm transmission service is designed to ensure deliverability.[441]

233. Midwest TDUs conclude that Zonal Deliverability Charge Hedges must be distributed "in proportion to the exposure to [Zonal Deliverability Charges] that is due to designated . . . long-term-firm network resources."[442] Midwest TDUs state that tying the availability and amount of Zonal Deliverability Charge Hedges to the funding of specific incremental network upgrades yields arbitrary results and has no valid basis. Midwest TDUs state that all network customers fund their allocated share of the entire MISO transmission system, whether they use more or less than their payment ratio of any particular network element. In return for LSEs' load ratio payments, Midwest TDUs contend that LSEs should receive either the full capacity value of their resources, or some fraction thereof that is in proportion to other LSEs located in the same zone.

c. Commission Determination

234. We deny Midwest TDUs' request for rehearing. We affirm the determination that Midwest TDUs' request for a hedge when zonal boundaries change is a collateral attack on the Commission's findings in the Locational Requirements Order and the Locational Requirements Compliance Order. Contrary to the requirements of those orders, Midwest TDUs' proposed complete hedge for all firm transmission capacity and resources would not recognize the impact of transmission constraints in resource planning.

235. We can find no basis for Midwest TDUs' claim that the Zonal Deliverability Charge Hedge is illusory. Per the tariff provision and processes in the Business Practices Manual, market participants must identify the network upgrade they are funding and the associated transmission service request in their application for the Zonal Deliverability Charge Hedge.[443] While it is true that a new network resource will only be evaluated for aggregate deliverability, this does not make the Zonal Deliverability Charge Hedge illusory. Rather, in the process of applying for firm transmission service from the new resource, an LSE can identify any network upgrades and thereby obtain a Zonal Deliverability Charge Hedge. Also, Midwest TDUs provide no basis for their claim that transmission service requests are unlikely to result in load-zone upgrades, and therefore we consider their position to be speculative.

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[441] *Id.* at 63-64.

[442] *Id.* at 65.

[443] *See* MISO Resource Adequacy Business Practices Manual, § 5.4.2.

236. Midwest TDUs are correct that MISO witness Hillman was referring to the Zonal Deliverability Charge Hedge, rather than the Zonal Deliverability Benefit as the Commission had concluded, in his discussion of hedging proportionate to transmission service payments. However, we find this error to have no significance for the Commission's determination in the June 11 Order and our affirmation of that determination in this order since the relation between the Zonal Deliverability Charge and transmission service payments played no role in the Commission's determination that the Zonal Deliverability Charge Hedge is reasonable. Rather, the basis for the Commission's determination that the Zonal Deliverability Charge Hedge is reasonable is because: (1) the hedge appropriately recognizes the economic value of new capacity that mitigates constraints, thereby improving the deliverability of resources used to serve peak demand in constrained zones; and (2) the hedge recognizes that market participants that fund network upgrades that increase import capability into a zone should have priority in receiving the financial benefit stemming from their investments.

237. We are not persuaded by Midwest TDUs' arguments in support of their position that Zonal Deliverability Charge Hedges should be distributed to all network resources in proportion to their exposure to the Zonal Deliverability Charge. The various deficiencies of the Zonal Deliverability Charge Hedge cited by Midwest TDUs, such as basing the hedge on network upgrades that increase the import limit into a zone, are needed to provide an incentive to improve deliverability into constrained zones. We consider the Zonal Deliverability Charge Hedge to be reasonable since improved deliverability will enhance reliability in peak demand periods. In contrast, Midwest TDUs' method of distributing the hedge will not enhance reliability since it provides no incentive for market participants to make the needed upgrades. Further, Midwest TDUs' distribution of hedges takes no account of deliverability and therefore defeats the purpose of the locational construct. For these reasons, we do not consider Midwest TDUs' method of tying the Zonal Deliverability Hedge to the resource MW – rather than the upgrade MW – to be reasonable.

238. Midwest TDUs justify the need to override these features and benefits of the MISO resource adequacy construct because LSEs need the certainty that the capacity value of their resources, including new resources, will be delivered. Inasmuch as Midwest TDUs' pleadings do not discuss any reliability benefits or other advantages of their method, we interpret Midwest TDUs' position to be that the Commission should accept their method because LSEs have a right to the full capacity value of their resources. We draw this conclusion based on their references to energy congestion hedges as the appropriate analogy for their capacity hedge method.[444] As discussed

[444] Midwest TDUs Request for Rehearing at 63.

above,[445] we find no basis in section 217 and Order No. 681 for a right to the capacity value of an LSE's resources.

239. We do not see any connection between the Zonal Deliverability Charge, and by inference the Zonal Deliverability Charge Hedge, and the transmission rate. As discussed,[446] the Zonal Deliverability Charge is not a transmission charge and therefore is not a payment for deliverability or compensation for planning, providing and operating the transmission system. Accordingly, we find no basis for Midwest TDUs' argument that in return for paying their load-ratio share of the costs of the transmission system, LSEs should receive the capacity value of their network resources.

4. Zonal Deliverability Benefit

a. June 11 Order

240. The Commission conditionally accepted MISO's proposal to offer market participants a Zonal Deliverability Benefit based on their *pro rata* share of demand within a zone. The Commission found it reasonable to allocate any excess debits, after Grandmother Agreements and the Zonal Deliverability Charge Hedge are funded, based on the relative share of each LSE's Planning Reserve Margin in the zone. The Commission stated that such an allocation ensures that the benefit is commensurate with the costs incurred for LSEs importing resources in the zone as well as providing a deliverability benefit to those LSEs that have managed their resource planning to recognize locational constraints. [447]

b. Requests for Rehearing

241. Midwest TDUs contend that the method of distributing revenues generated from the Zonal Deliverability Charge to LSEs would unfairly redistribute resources from transmission dependent utilities to large vertically-integrated utilities.[448] Midwest TDUs add that this redistribution is inconsistent with Order No. 888-A, in which, according to Midwest TDUs, the Commission "determined that the integrated network's transfer capabilities, including both its capability to import power from outside zones and its

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[445] *Supra* section VI.F.2.c.v.

[446] *Supra* section VI.F.2.c.i.

[447] June 11 Order, 139 FERC ¶ 61,199 at P 150.

[448] Midwest TDUs Request for Rehearing at 49-50.

capabilities to move power among sub-areas of a transmission provider's system, are all available to all network customers for first-come, first-served usage."[449]

c. Commission Determination

242. We deny Midwest TDUs' request for rehearing. We do not consider the *pro rata* allocation of the Zonal Deliverability Benefit to be an expropriation of the value of existing resource commitments of transmission dependent utilities, as Midwest TDUs claim. As discussed in sections VI.F.2.c and VI.F.3.c, existing resource commitments have no bearing on the price of reliability being paid at the load location. Accordingly, these commitments do not provide a basis for allocating excess credits in each zone.

243. The Zonal Deliverability Benefit is based on the difference between the resource costs paid by LSEs in a zone and the revenues paid to resources that cleared in the auction for any zone. Hence, as discussed in section VI.F.2.c, firm transmission service and the Commission's precedent on firm transmission rights are not the basis for locational market prices and the Zonal Deliverability Charge. Accordingly, Midwest TDUs' citations to Commission precedent on use of the transmission system by network customers are not relevant to the appropriate allocation of the zonal deliverability benefit.

G. Power Purchase Agreements as Capacity Resources

1. Seasonal Power Purchase Agreements

a. June 11 Order

244. In the June 11 Order, the Commission rejected Dairyland's request for clarification that seasonal power purchase agreements could qualify as capacity resources even if they do not meet the proposed definition of a diversity contract. The Commission stated that it had previously accepted the Tariff provisions regarding power purchase agreements in the Locational Requirements Order and the Locational Requirements Compliance Order. Therefore, the Commission rejected Dairyland's arguments as collateral attacks on the Commission's findings in those orders.[450]

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[449] *Id.* at 49 (citing Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,304-05).

[450] June 11 Order, 139 FERC ¶ 61,199 at P 339.

b. Request for Rehearing

245. Dairyland argues that that its requested clarification did not collaterally attack any Commission order.[451] Dairyland therefore renews its request for clarification.

246. Illinois Municipal requests that the Commission clarify that a power purchase agreement "that ends during the [P]lanning [Y]ear, or otherwise extends for only part of the [P]lanning [Y]ear, can be a qualified Capacity Resource if all of the other qualifications are met and that capacity will be replaced through an extension of the existing contract or under the terms of an otherwise qualifying new contract or generation ownership."[452] Although this argument was included in Illinois Municipal's protest, Illinois Municipal states that the Commission neglected to address the point in the June 11 Order. Illinois Municipal explains that section 69A.3.1.c of the Tariff allows a power purchase agreement to qualify as a Capacity Resource, but does not explicitly include an agreement for any term less than the Planning Year. Illinois Municipal argues that MISO's proposal is designed to ensure that capacity is available to meet expected forecasts. In this respect, Illinois Municipal claims that it "should not matter whether that capacity comes, in part, from one contract or another, or from a contract and a new facility, or any verifiable combination of contract, facility or demand response."[453] Furthermore, Illinois Municipal contends that allowing partial-year power purchase agreements to qualify may provide needed flexibility and encourage necessary capacity additions.

c. Commission Determination

247. While Dairyland characterizes its request as pertaining to the definition of Diversity Contracts, in fact it is asking, and Illinois Municipal is asking, for interpretation of the provisions applicable to power purchase agreements. As the Commission stated in the June 11 Order, these provisions were accepted in previous orders. Therefore, they are beyond the scope of this proceeding and for this reason we deny the rehearing requests.

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[451] Dairyland Request for Rehearing at 6-7.

[452] Illinois Municipal Request for Rehearing at 3-4.

[453] *Id.* at 4.

H. Load Forecasting in Retail Choice Areas

1. June 11 Order

248. In the June 11 Order, the Commission found unreasonable MISO's proposed default method for coincident peak demand allocation where an electric distribution company in a retail-choice region does not provide a procedure for assigning LSEs' obligations, and MISO and the electric distribution company cannot agree on an alternative method. Under MISO's proposed default methodology, MISO would apportion the daily capacity charges related to obligations arising from the planning reserve requirement during the Planning Year *pro rata* on a daily energy basis. The Commission explained that MISO's proposed default methodology was unreasonable because the methodology relied on energy data, rather than capacity data. Accordingly, the Commission directed MISO to use the peak load contribution methodology, which relies on capacity data, as its default methodology for assigning capacity obligations. In addition, with respect to entities that lack data necessary to use the peak load contribution methodology, the Commission directed MISO to use a daily peak load methodology. However, once MISO has acquired sufficient historical data to develop peak load contribution for each LSE, the Commission directed MISO to begin utilizing the peak load contribution methodology.[454]

2. Request for Rehearing

249. Coalition of MISO Customers argue that the Commission's holding is unduly discriminatory because it will result in the resource adequacy requirements of LSEs in retail choice states being calculated according to a different methodology than will be used for LSEs in non-retail choice states.[455] Additionally, Coalition of MISO Customers argue that the default of using a daily peak load methodology may result in an over-procurement or an under-procurement of capacity relative to the levels needed to meet a forecast coincident peak load.

250. Coalition of MISO Customers also argue that the June 11 Order fails to consider a just and reasonable alternative to approving two different methodologies for determining LSEs' resource adequacy obligations based on the location of the LSEs' service territories.[456] Coalition of MISO Customers point out that the Commission directs MISO

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[454] June 11 Order, 139 FERC ¶ 61,199 at PP 222-223.

[455] Coalition of MISO Customers Request for Rehearing at 4.

[456] *Id.* at 5.

to essentially collect data on LSEs until it gathers sufficient information to develop a peak load contribution for each LSE. Coalition of MISO Customers contend that MISO should use actual historical usage data presently in MISO's or the electric distribution company's possession for LSEs serving load in retail choice states. Coalition of MISO Customers assert that such a requirement would minimize the use of different methodologies for calculating resource adequacy obligations by requiring MISO to use historical data where available.[457]

3. Commission Determination

251. We deny Coalition of MISO Customers' request for rehearing. We find that the use of the daily peak load contribution methodology until sufficient data exists to use the peak load contribution methodology does not represent undue discrimination against LSEs in retail choice states. The difference in methodology is not undue because, as the Commission found in the June 11 Order, there may not be sufficient data to use the peak load contribution methodology initially in some instances. Requiring MISO to use available historical information, as Coalition of MISO Customers recommend, does nothing to resolve this data gap because MISO cannot force electric distribution companies to provide the necessary data.[458]

I. Energy Efficiency Resources

1. June 11 Order

252. In the June 11 Order, the Commission conditionally accepted MISO's proposal to include Energy Efficiency Resources as Planning Resources in its resource adequacy construct, subject to MISO's submission of tariff revisions to add to the Tariff the terms and conditions of service for Energy Efficiency Resources.[459] In response to concerns that the owners of Energy Efficiency Resources could be compensated twice, the Commission found that the Tariff "is clear that energy efficiency resources are treated as

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[457] *Id.* at 5-6.

[458] June 11 Order, 139 FERC ¶ 61,199 at P 215 (MISO also claims that it will be unable to obtain the necessary retail information to calculate forecasts using the peak load contribution because MISO cannot force them to provide the data).

[459] *Id.* PP 233-236.

resources and not calculated in the load forecast."[460] As a result, the Commission stated that double compensation is not allowable under the Tariff.

2. Request for Rehearing

253. Wisconsin Electric requests that the Commission clarify that the market participant that registers an Energy Efficiency Resource must be the market participant that also increases its reported Coincident Peak Demand.[461] Wisconsin Electric argues that if a market participant other than the market participant that registers an Energy Efficiency Resource is required to increase its reported Coincident Peak Demand, the owner of the resource would effectively be compensated twice.[462] According to Wisconsin Electric, the owner of the resource would be compensated twice—first, by not being required to purchase capacity from the LSE, and again, by selling the resource's capacity. Wisconsin Electric points out that in such a case, the utility would still be required to purchase the amount of capacity available from the Energy Efficiency Resource from the market.

254. In the alternative, Wisconsin Electric seeks rehearing of the June 11 Order to the extent that it would permit double compensation, as described above. Wisconsin Electric states that the Commission's failure to ensure against double compensation would be arbitrary, capricious and an abuse of discretion. Moreover, Wisconsin Electric asserts that such a determination would result in an unjust and unreasonable shifting of costs among market participants in violation of section 205 of the FPA.[463]

3. Commission Determination

255. We deny Wisconsin Electric's request for rehearing. We understand Wisconsin Electric's position to be that because retail customers can sell Energy Efficiency Resources and thereby receive double compensation—first, for the resource sale and second as a reduced payment to the utility—it considers MISO's Energy Efficiency Resource proposal to be unreasonable. To remedy this outcome, Wisconsin Electric proposes that only LSEs serving the service territory of the retail customer should be allowed to register Energy Efficiency Resources. We disagree. We do not consider it

[460] *Id.* P 234.

[461] Wisconsin Electric Request for Rehearing at 6.

[462] *Id.* at 4-5.

[463] *Id.* at 6-7.

reasonable to restrict the ownership or contractual rights to Energy Efficiency Resources to the LSE making the peak demand forecast. Entities other than LSEs, such as industrial customers, can own Energy Efficiency Resources and we see no reason to foreclose these entities from participation in MISO's resource adequacy plan. For this reason, we consider it to be unreasonable to bar market participants from offering Energy Efficiency Resources into MISO's resource adequacy plan.

J. Cost of New Entry

1. June 11 Order

256. In the June 11 Order, the Commission conditionally accepted MISO's proposal to set at CONE both the maximum price associated with Zonal Resource Credit offers and the auction clearing price where there is insufficient volume to cover the relevant zone's Local Clearing Requirement or Planning Reserve Margin Requirement.[464] The Commission explained that the existing process, which requires MISO to make a section 205 filing with its annual CONE determination, appropriately details the assumptions and methodologies used to derive the CONE estimate. The Commission required MISO to revise the definition of CONE to indicate that CONE represents the costs within a zone. Further, the Commission required MISO to propose tariff revisions that would require MISO to file its CONE estimate September 1 of each year.

2. Request for Rehearing

257. Illinois Municipal agrees that MISO is required to file any future CONE determination with the Commission pursuant to section 205 of the FPA. However, Illinois Municipal argues that "to the extent that the Commission is in this proceeding approving past practices for setting CONE values in the penalty context . . . it should grant rehearing and make clear it makes no such finding here."[465] Illinois Municipal contends that MISO's historical methods of estimating CONE are insufficient to determine CONE in light of the significance of CONE in setting capacity rates and charges under MISO's resource adequacy construct.

3. Commission Determination

258. We clarify that the Commission's determination in the June 11 Order was not accepting a method for setting CONE values. MISO's filing did not specify a CONE

[464] June 11 Order, 139 FERC ¶ 61,199 at PP 281, 288.

[465] Illinois Municipal Request for Rehearing at 8.

estimate, or a method for setting the zonal CONE values, and therefore the Commission's acceptance of the proposed CONE provision in the June 11 Order did not encompass such estimates or methods.

K. Behind the Meter Generation

1. Request for Rehearing

259. Illinois Municipal contends that the Commission failed to respond to its arguments pertaining to Behind the Meter Generation in the June 11 Order.[466] Illinois Municipal explains that such an oversight constitutes a failure of reasoned decision-making. According to Illinois Municipal, Behind the Meter Generation can qualify as a Capacity Resource. However, under the MISO Tariff, Behind the Meter Generation cannot be netted against an LSE's Coincident Peak Demand in the Forecast LSE Requirement calculation. Thus, Illinois Municipal states it is unclear whether, pursuant to section 69A.9 of the Tariff, an LSE can opt out for a portion of a particular load using its Behind the Meter Generation to do so. Illinois Municipal urges the Commission to require that the Tariff be revised to make two clarifications. First, Illinois Municipal states that the Tariff should make clear that an LSE can opt out for "a portion of the load of a member of a joint action agency."[467] Rather than opting out member-by-member, Illinois Municipal states that such a revision would allow joint action agencies to opt out of only part of the member's load. Second, Illinois Municipal requests that the Tariff be revised to clarify that a fixed resource adequacy plan "can be flexible enough to allow switching capacity alternatives." For example, Illinois Municipal explains that LSEs should be permitted to satisfy their resource adequacy requirements by using Behind the Meter Generation or capacity from a power purchase agreement, or both.

2. Commission Determination

260. We clarify that the opt-out provision and an LSE's plan for showing resource sufficiency are separate issues. When an LSE opts out for all or a portion of its peak load requirement with a fixed resource adequacy plan, it must show that there are sufficient resources to meet the peak load requirement of the fixed resource adequacy plan portion. For an LSE using Behind the Meter Generation, the LSE must list the Behind the Meter Generation resources as Capacity Resources - not as a load reduction. We see no need to make the tariff revisions requested by Illinois Municipal. The opt-out can be for a portion of the LSE's load, which could include Joint Action Agency loads. Also, there is

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[466] *Id.* at 10.

[467] *Id.* at 9.

no restriction on the resources (or power purchase agreements) used in a fixed resource adequacy plan. The requirement that Behind the Meter Generation be counted as a Capacity Resource is only a restriction pertaining to how this resource is accounted for in the Planning Reserve Margin Requirement calculation. There are no provisions in Module E-1 limiting the use or mix of resources listed in sections 69A.3.1 through 69A.3.6, and therefore there is no need to revise the Tariff.

The Commission orders:

(A) The requests for rehearing of the June 11 Order are denied, as discussed in the body of this order.

(B) The requests for clarification are granted, in part, as discussed in the body of this order.

By the Commission. Commissioner Honorable is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.